Panhandle Oil and Gas Inc.

2013 Annual Report

For defined terms used in this report please see

"Definitions" page of the attached Form 10-K.

To Our Fellow Shareholders

Fiscal 2013 provided both exceptional financial and operating results for the Company. Our team was able to not only record an 89% increase in net income over fiscal 2012, but also significantly increase oil, NGL and natural gas production and reserves. These results were achieved by the reinvestment of cash flow in high-quality drilling projects. Panhandle is in the enviable position of having very low debt coupled with strong cash flows, thus allowing the Company to deploy the capital necessary to take full advantage of all drilling opportunities on our fee mineral acreage that are expected to generate good rates of return. These prudent drilling investments continue to yield exceptional production and reserve growth for Panhandle.

2013 Highlights

- Recorded net income of $13,960,049, $1.67 per share, for 2013, an increase of 89% over 2012 net income.
- Generated cash from operating activities of $37.4 million, which fully funded all capital expenditures.
- Increased oil, NGL and natural gas sales revenues 48% over fiscal 2012 levels.
- Increased 2013 production to 13.0 Bcfe, a 22% increase over 2012 and the largest in Company history.

The Mineral Acreage Advantage

Economic Impact of Working Interest (W.I.) Participation on Mineral Acres

Typical Fayetteville Shale Well

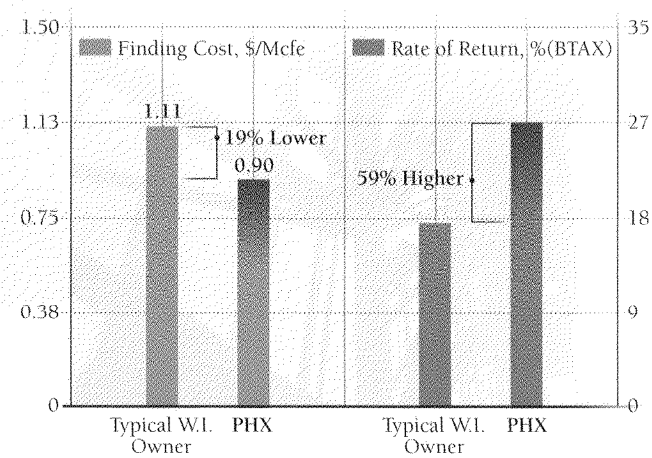
Assumptions

- PHX ownership – 5% W.I., 5% NRI
- Typical ownership – 5% W.I., 4.0625 NRI
- Reserves 3.0 Bcf
- Gross well cost – $2,700,000
- Wellhead prices – 10/24/13 NYMEX Strip, adjusted for basis

Fayetteville Well Results

- 19% Lower Finding Cost
- 59% Higher Rate of Return

This advantage applies to all plays in which Panhandle drills on owned mineral acres



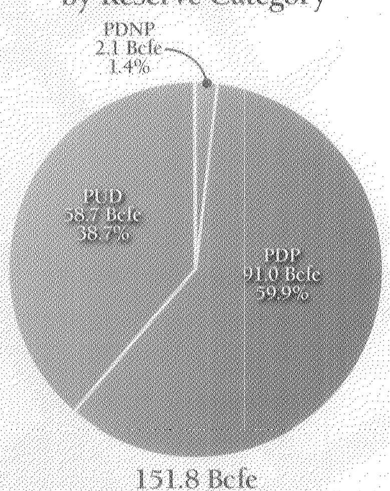
- Increased 2013 high value oil production 53% over 2012.
- Increased proved reserves 22% to 151.8 Bcfe, increased proved oil reserves 53% to 1.6 million barrels and increased proved NGL reserves 105% to 1.6 million barrels.
- Maintained an ultra-strong balance sheet with debt to equity of 8.6%.

Financial Review

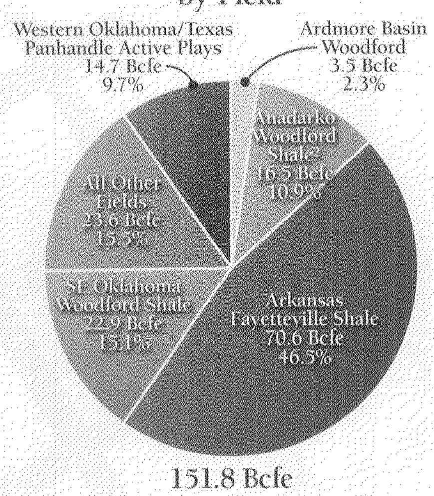
The attached FORM 10-K contains a complete discussion and analysis of the Company's financial results for 2013 on pages 26-36. A brief summary is provided in the three following paragraphs.

Panhandle recorded net income of $13,960,049, or $1.67 per share for the year. This compared to net income of $7,370,996, or $0.88 per share, for fiscal 2012. Net cash provided by operating activities increased 47% to $37,402,109 for fiscal 2013, versus 2012. Capital expenditures for drilling and equipping wells in fiscal 2013 totaled $26,765,785, providing in excess of $10 million of free cash flow. Debt was reduced by $6.6 million during the year.

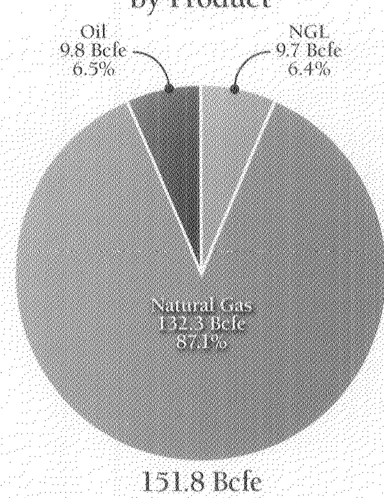
SEC Proved Reserves by Reserve Category



SEC Proved Reserves by Field



SEC Proved Reserves by Product

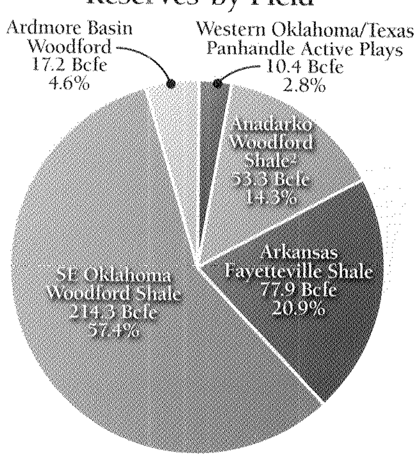


Total revenues for 2013 were $62,889,120, increasing 30% from $48,532,317 for 2012. Fiscal 2012 revenues included lease bonuses and rentals of $7,152,991, as compared to $938,846 in 2013. Oil, NGL and natural gas sales revenues increased $19,787,444, or 48%, to $60,605,878 in 2013, as compared to 2012 as a result of a 22% increase in Mcfe production and a 21% increase in the average per Mcfe sales price. The average sales price per Mcfe of production during 2013 was $4.68 compared to $3.86 in 2012 and was driven both by increased natural gas prices and expanding high value oil and NGL production.

Further improving 2013 financial results was a reduction in our cost structure (DD&A, LOE, production taxes and G&A) of 4.1%, from $3.41 per Mcfe to $3.27 per Mcfe in 2013.

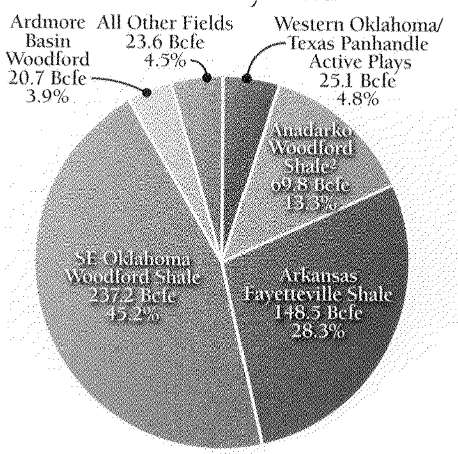
Oil production increased 53% in 2013 to 234,084 barrels from 153,143 barrels in 2012, and natural gas production increased 1,814,031 Mcf, or 20%, compared to 2012. Natural gas production volume increases were principally attributable to the development of the Company's Fayetteville Shale properties and natural gas production from wells drilled in oil and NGL rich plays.

Probable & Possible Reserves[1] by Field



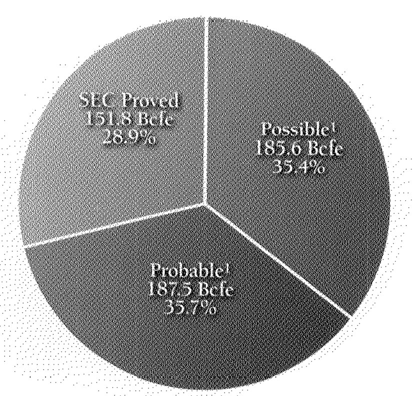
373.1 Bcfe

Proved, Probable and Possible Reserves by Field



524.9 Bcfe

Proved, Probable and Possible Reserves by Reserve Category



524.9 Bcfe

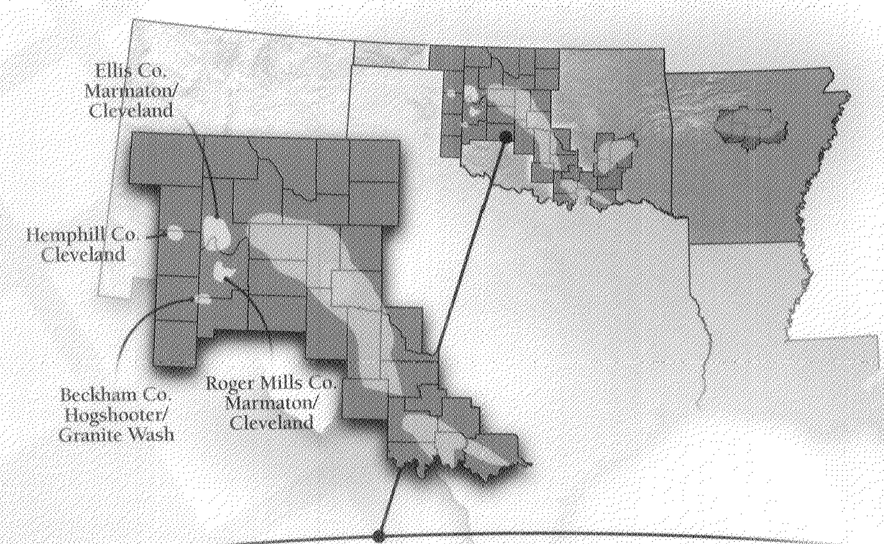
[1] Prepared in accordance with PRMS [2] Cana Core and Southern Anadarko Woodford

Drilling expenditures over the prior 24 months targeting oil and NGL rich plays, principally in Western Oklahoma and the Texas Panhandle and two southern Oklahoma Woodford shale plays, were responsible for the increased oil volumes. In addition, 111,897 barrels of NGL were sold in fiscal 2013, which was a 13% increase versus 2012.

Operational Highlights and Developments

The primary operational focus for Panhandle in 2013 was the development of oil and NGL rich properties in the Anadarko Basin of southern and western Oklahoma and the Texas Panhandle.

Approximately 58% of the Company's 2013 approved drilling capital expenditures were directed to this area. Another 18% of approved capital was directed to oil and NGL development drilling primarily in the Ardmore Basin of southern Oklahoma, the Permian Basin of west Texas and the Bakken in North Dakota. As a result of this oil and NGL focused activity, the Company's 2013 oil production reached a record high of 234,084 barrels, which was a 53% increase over 2012, and 2013 NGL production increased 13% over 2012 to a record high of 111,897 barrels. The Company's 2013 proven oil reserves increased 53% over 2012 to 1,643,303 barrels, while 2013 proven NGL reserves increased 105% over 2012 to 1,616,126 barrels, both being the highest in Company history.



Western Oklahoma/Texas Panhandle

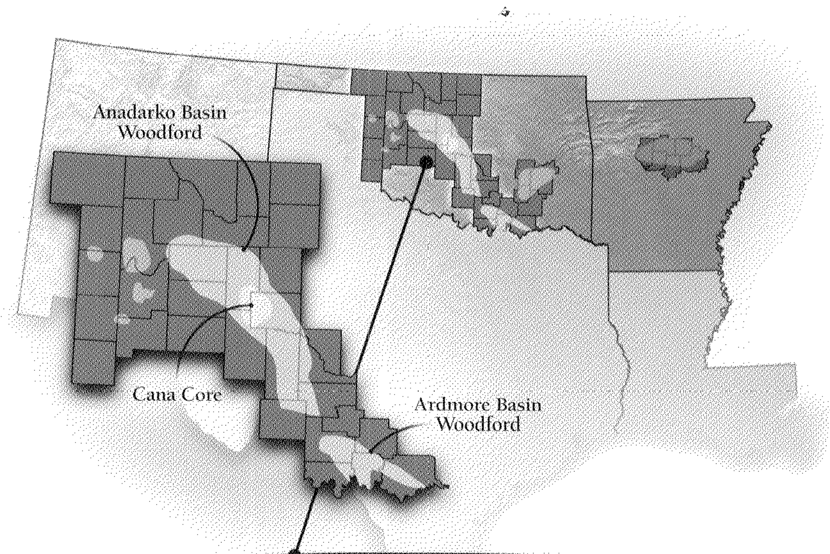
Natural gas production in 2013 also achieved a record high of 10.9 Bcf, which was a 20% increase over 2012, while proven natural gas reserves increased to a record 132.3 Bcf, a 17% increase over 2012.

Panhandle's 3P (proved, probable and possible) reserves grew 18.7% in 2013 to 525 Bcfe. The Company has continued to build a diverse opportunity set of over 4,500 undeveloped locations across multiple states, plays and basins for ongoing oil, NGL and natural gas production and reserve growth.

Panhandle is deploying capital, with the built-in economic advantage of drilling on owned mineral acreage, in many of the industry's best plays with the best operators in these plays. This strategy will allow the Company to provide excellent operational results on a consistent basis.

Southern & Western Oklahoma/ Texas Panhandle

The significant oil and NGL production and reserve growth generated by Panhandle in 2013 was primarily the result of horizontal development drilling in four conventional plays in western Oklahoma and the Texas Panhandle, as well as in the southern Oklahoma Woodford shale plays. The areas of focus were a Cleveland oil play in northern Hemphill County, Texas, two Marmaton/



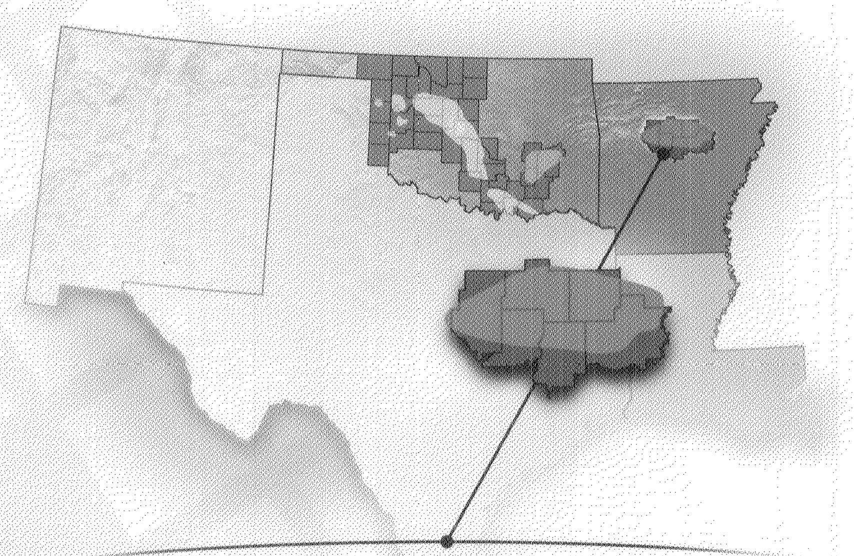
Western & Southern Oklahoma

Cleveland oil plays in Ellis and Roger Mills Counties, Oklahoma, the Hogshooter/Granite Wash oil play in Beckham County, Oklahoma, and the Woodford Shale oil plays in the southern Anadarko and Ardmore Basins of southern Oklahoma. In 2013, we participated in 88 gross working interest wells in these areas with an average NRI of 4.2% and had a royalty interest only in another 80 gross wells.

These areas hold significant ongoing oil and liquids rich development potential for the Company, with a total of 1,202 undeveloped proved, probable and possible locations with 3P reserves, net to the Company, of 71.3 Bcf of natural gas, 1,419,000 barrels of oil and 3,245,000 barrels of NGL. Key operators in this oil and NGL rich region continue to remain very active, and management anticipates a majority of the Company's 2014 capital investing will be dedicated to these areas.

Arkansas Fayetteville Shale

The Fayetteville Shale continued to be a very active development area for the Company in 2013. The Company allocated approximately 23% of its approved 2013 drilling and completion capital expenditures to this play, while participating in 128 gross working interest wells with an average NRI of 3.2%. Panhandle had a royalty interest only in another 84 wells drilled in the play.



Arkansas Fayetteville Shale

The Company has significant development potential remaining in this play with a total of 2,069 identified undeveloped proved, probable and possible locations containing undeveloped 3P reserves of 113.3 Bcf net to Panhandle.

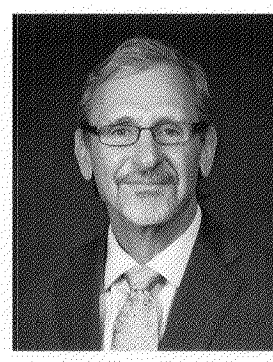
The core of the Fayetteville shale continues to be one of the lowest cost, dry natural gas resource plays in the United States, and the key operator in the area remains active in the development of the play. Management anticipates that the development of our holdings in this play will continue to be a significant part of our investment activity in 2014.

Looking Forward

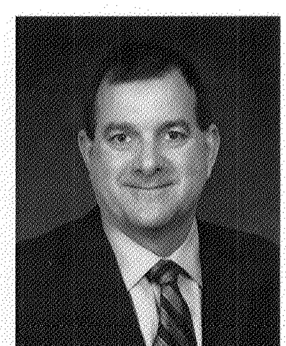
Panhandle's primary mission is to build additional value per share of stock through the allocation of capital to drilling and acquisition projects which are expected to maximize rates of return to the Company. Our principal method of accomplishing this goal is through drilling wells, on a non-operated basis, principally on owned fee mineral acreage.

We continue to accomplish this while maintaining a longer-term focus and a low-to-moderate risk profile for drilling and acquisition capital expenditures. This focus and discipline of strategy has served Panhandle well and, combined with the capital efficiency advantage of drilling wells on owned mineral acres, gives the Company the opportunity to continually deliver additional value per share.

We will continue to have the discipline to make wise investments of Company capital. Panhandle is in an enviable financial and operating position, and we will take full advantage of all opportunities which will allow the Company to continue the momentum that has been established.



Michael C. Coffman
President
Chief Executive Officer



Paul Blanchard
Senior Vice President
Chief Operating Officer

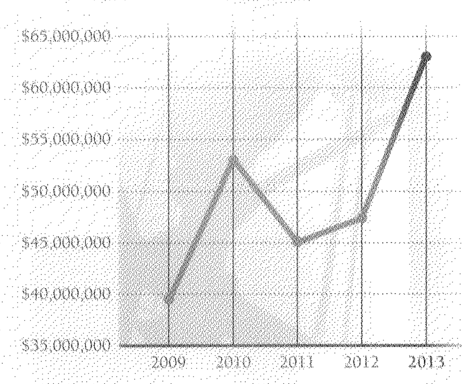
Panhandle Oil and Gas Inc.

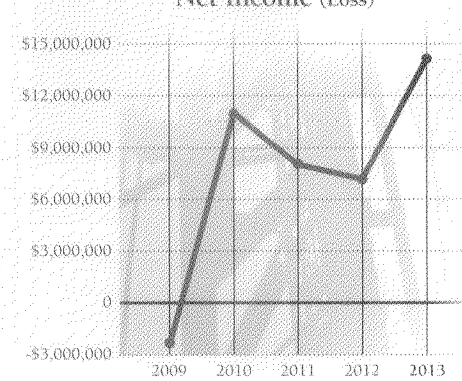
Financial & Operating Highlights

	2013	2012	2011
Revenue and Earnings			
Revenue	$ 62,889,120	$ 48,532,317	$ 44,976,651
Net Income (loss)	$ 13,960,049	$ 7,370,996	$ 8,493,912
Earnings (loss) per Share	$ 1.67	$ .88	$ 1.01
Average Shares Outstanding	8,356,904	8,360,931	8,393,890
Net Cash Provided by Operating Activities	$ 37,402,109	$ 25,371,196	$ 29,283,929
Costs Incurred In Oil and Gas Activities	$ 29,180,775	$ 46,193,825	$ 27,289,121
Debt	$ 8,262,256	$ 14,874,985	$ 0

	2013	2012	2011 (1)
Production			
MCFE Produced	12,962,215	10,583,440	8,922,503
Increase (Decrease) from Prior Year	22%	19%	0%
Average Sales Price per MCFE	$ 4.68	$ 3.86	$ 4.87
Barrels Oil Produced	234,084	153,143	104,141
Average Sales Price per Barrel	$ 91.56	$ 90.13	$ 88.00
MCF Natural Gas Produced	10,886,329	9,072,298	8,297,657
Average Sales Price per MCF	$ 3.31	$ 2.62	$ 4.13
Barrels NGL Produced	111,897	98,714	–
Average Sales Price per Barrel	$ 27.67	$ 33.23	–
Average Production Costs (per mcf equivalent) (2)	$ 1.06	$ 1.00	$ 1.11

(1) Proceeds from the sale of natural gas liquids have been included in natural gas sales and are reflected in the sales price per Mcf of natural gas for 2011. 2012 was the first year the Company produced sufficient volumes of NGL to warrant separate disclosure.
(2) Production costs include well operating costs, production taxes and handling, marketing and other fees paid on natural gas sales.





In 2013, Panhandle participated with a working interest in 243 wells and had a royalty interest in 286 wells that were either completed, drilling or testing at year end.

Working Interest Wells

Category	2013	2012	2011
Drilling	13	9	10
Testing	25	51	32
Producing	203	116	114
	(64 oil, 139 gas)	(27 oil, 89 gas)	(20 oil, 94 gas)
Dry Holes	2	1	2
Total	243	177	158

Royalty Interest Wells

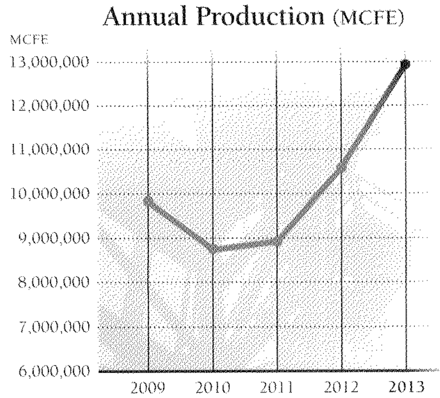
Category	2013	2012	2011
Drilling, Testing	15	15	6
Producing	271	242	202
	(68 oil, 203 gas)	(40 oil, 202 gas)	(29 oil, 173 gas)
Dry Holes	0	2	0
Total	286	259	208

Reserves & Production

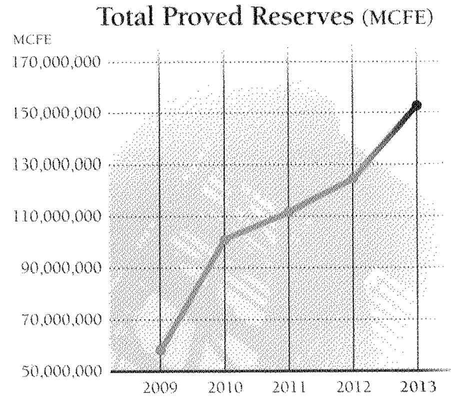
	2013	2012	2011
Reserves			
Proved Developed Reserves:			
Barrels of NGL (1)	764,321	494,160	386,774
Barrels of Oil	1,037,721	849,548	759,989
MCF of Gas	82,298,833	65,733,119	60,193,878
MCFE	93,111,085	73,795,367	67,074,456
Proved Undeveloped Reserves:			
Barrels of NGL (1)	851,805	294,582	404,874
Barrels of Oil	605,582	222,771	83,749
MCF of Gas	49,990,334	47,780,937	41,644,106
MCFE	58,734,656	50,885,055	44,575,844
Total Proved Reserves:			
Barrels of NGL (1)	1,616,126	788,742	791,648
Barrels of Oil	1,643,303	1,072,319	843,738
MCF of Gas	132,289,167	113,514,056	101,837,984
MCFE	151,845,741	124,680,422	111,650,300
Increase over prior year	22%	12%	8%
10% Discounted Estimated Future Net Cash Flows (before federal income taxes @ SEC pricing)			
Proved Developed	$125,186,445	$ 87,587,058	$106,464,138
Proved Undeveloped	$ 51,276,694	$ 27,151,132	$ 29,977,891
Total	$176,463,139	$114,738,190	$136,442,029
SEC Pricing			
NGL/Barrel	$ 27.28	$ 35.70	$ 38.91
Oil/Barrel	$ 89.06	$ 89.41	$ 90.28
Gas/MCF	$ 3.33	$ 2.51	$ 3.81

(1) Year end 2011 was the first year the Company had sufficient volumes of NGL to warrant reserve volumes disclosure. These NGL are associated with the continuing drilling activity in western Oklahoma and the Texas Panhandle, which includes many plays (horizontal Granite Wash, Hogshooter Wash, Cleveland, Marmaton, Tonkawa and the Anadarko Basin "Cana" Woodford Shale) producing significant volumes of NGL.

Annual Production (MCFE)



Total Proved Reserves (MCFE)



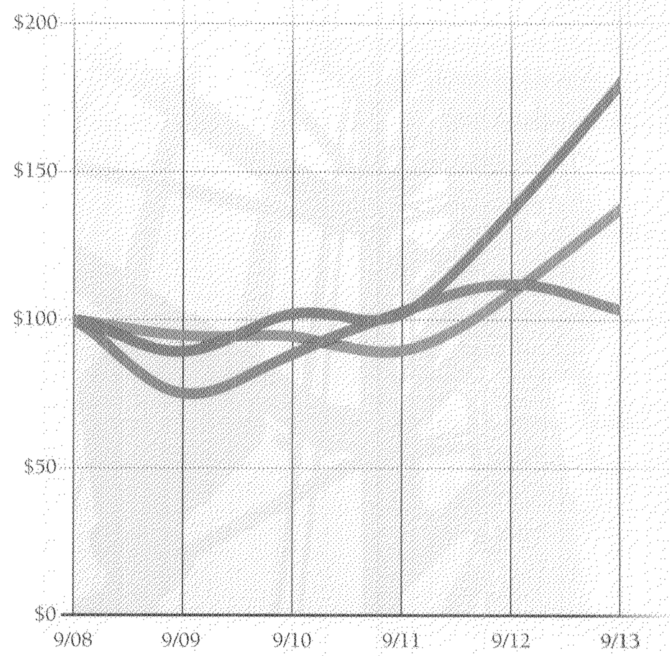
Panhandle Oil and Gas Inc.

Comparison of 5-Year Cumulative Total Return*

Among Panhandle Oil & Gas Inc., The S&P Smallcap 600 Index and The S&P Oil & Gas Exploration & Production Index

The graph to the right compares the cumulative 5-year total return to shareholders on Panhandle Oil & Gas Inc's common stock versus the cumulative total returns of the S&P Smallcap 600 Index and the S&P Oil & Gas Exploration & Production Index. The graph assumes that the value of the investment in the Company's common stock and in each of the indexes (including reinvestment of dividends) was $100 on 9/30/2008 and tracks it through 9/30/2013.

* $100 invested on 9/30/08 in stock or index-including reinvestment of dividends. Fiscal year ending September 30.



Securities Information

The Company's Class A Common Stock ("common stock") is listed on the New York Stock Exchange (symbol PHX). The following table sets forth the high and low trade prices of the common stock during the periods indicated.

Quarter Ended	High	Low
December 31, 2011	$ 36.00	$ 26.18
March 31, 2012	$ 33.74	$ 28.05
June 30, 2012	$ 30.57	$ 24.16
September 30, 2012	$ 33.49	$ 27.85
December 31, 2012	$ 31.70	$ 24.70
March 31, 2013	$ 30.63	$ 26.83
June 30, 2013	$ 31.12	$ 27.00
September 30, 2013	$ 32.86	$ 27.27

As of November 25, 2013, there were 1,474 holders of record of Panhandle's Class A common stock and approximately 3,700 beneficial owners.

SEC and NYSE Certifications

The Form 10-K, included herein, which was filed by the Company with the Securities and Exchange Commission (SEC) for the fiscal year ended September 30, 2013, includes, as exhibits, the certifications of our chief executive officer and chief financial officer required to be filed with the SEC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. The Company has also filed with the New York Stock Exchange (NYSE) the 2013 annual certification of its chief executive officer confirming that the Company has complied with the NYSE corporate governance listing standards pursuant to Section 303A.12(a) of those standards.

During the past two years, cash dividends have been declared and paid as follows on the Class A Common Stock:

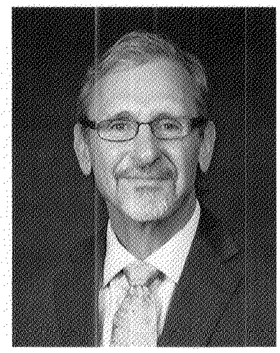
Date	Rate Per Share
December 2011	$ 0.07
March 2012	$ 0.07
June 2012	$ 0.07
September 2012	$ 0.07
December 2012	$ 0.07
March 2013	$ 0.07
June 2013	$ 0.07
September 2013	$ 0.07

While the Company expects to continue to pay dividends on its common stock, the payment of future cash dividends will depend upon, among other things, financial condition, funds from operations, the level of capital and development expenditures, future business prospects, contractual restrictions and any other factors considered relevant by the board of directors. The Company's credit facility also contains provisions limiting the amount of dividends that can be paid.

Stock Split History

May 1982	10-for-1
May 1999	3-for-1
February 2004	2-for-1
January 2006	2-for-1

Officers



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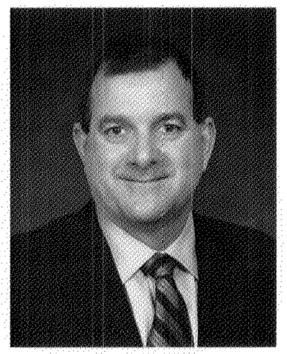

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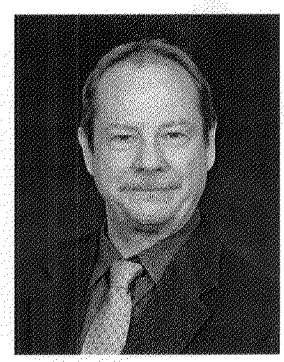


Ben Spriestersbach
Vice President, Land

Lonnie J. Lowry
Vice President
Chief Financial Officer, Secretary

Robb Winfield
Controller
Chief Accounting Officer

Corporate Headquarters

Grand Centre Building
5400 N. Grand Blvd.
Suite 300
Oklahoma City, OK 73112

Internet Address

Company financial information, public disclosures and other information are available through Panhandle's website at:
www.panhandleoilandgas.com

Counsel

Lon Foster III
Fellers, Snider, Blankenship, Bailey & Tippens, P.C.
Oklahoma City, Oklahoma

Stock Exchange

New York Stock Exchange
Symbol: PHX

Independent Registered Public Accounting Firm

Ernst & Young LLP
Oklahoma City, Oklahoma

Stock Transfer & Dividend Paying Agent

Standard U.S. postal mail:

Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078

Overnight/express delivery:

Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021

Toll free within U.S. and Canada
1-800-884-4225
Outside U.S. and Canada
1-781-575-2879

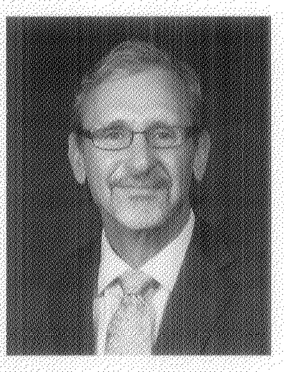
Website:

www.computershare.com

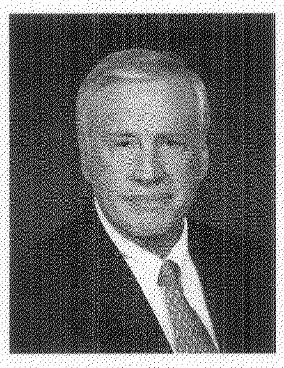
Email inquiry address for investors:

web.queries@computershare.com

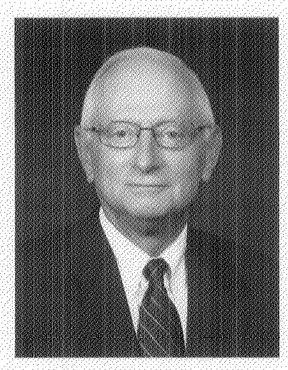
Board Of Directors



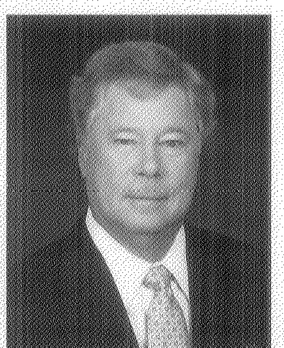
Michael C. Coffman
President
Chief Executive Officer



Duke R. Ligon
Attorney
(1) (3)

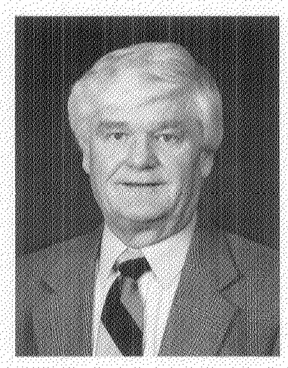


Robert O. Lorenz
Lead Independent Director
(1) (2)



Robert A. Reece
Attorney
(1) (3)

Robert E. Robotti
Robotti & Company, LLC
(2) (3)



Darryl G. Smette
Executive Vice President of Marketing & Midstream
Devon Energy Corporation
(1) (2)

H. Grant Swartzwelder
PetroGrowth Advisors
(2) (3)

(1) Member audit committee
(2) Member compensation committee
(3) Member governance and nominating committee

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

FORM 10-K

Panhandle
Oil and Gas Inc.

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED SEPTEMBER 30, 2013

Commission File Number: 001-31759

PANHANDLE OIL AND GAS INC.

(Exact name of registrant as specified in its charter)

OKLAHOMA	73-1055775
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Grand Centre, Suite 300, 5400 N. Grand Blvd., Oklahoma City, OK 73112
(Address of principal executive offices) (Zip code)

Registrant's telephone number: (405) 948-1560

Securities registered under Section 12(b) of the Act:

CLASS A COMMON STOCK (VOTING)	NEW YORK STOCK EXCHANGE
(Title of Class)	(Name of each exchange on which registered)

Securities registered under Section 12(g) of the Act:
(Title of Class)

CLASS B COMMON STOCK (NON-VOTING) $1.00 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in 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

Indicate by check mark whether the registrant (1) has 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.
X Yes ___ No

(Facing Sheet Continued)

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files.

X Yes ___ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the 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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer___ Accelerated filer X Non-accelerated filer___ Smaller reporting company___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

___ Yes X No

The aggregate market value of the voting stock held by non-affiliates of the registrant, computed by using the $28.65 per share closing price of registrant's Common Stock, as reported by the New York Stock Exchange at March 31, 2013, was $201,942,992. As of December 1, 2013, 8,231,254 shares of Class A Common Stock were outstanding.

Documents Incorporated By Reference

The information required by Part III of this Report, to the extent not set forth herein, is incorporated by reference from the registrant's Definitive Proxy Statement relating to the annual meeting of stockholders to be held on March 5, 2014, which definitive proxy statement will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Report relates.

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DEFINITIONS

The following defined terms are used in this report:

"Bbl" means barrel.

"Bcf" means billion cubic feet.

"Bcfe" means natural gas stated on a Bcf basis and crude oil and natural gas liquids converted to a billion cubic feet of natural gas equivalent by using the ratio of one million Bbl of crude oil or natural gas liquids to six Bcf of natural gas.

"Board" means board of directors.

"BTU" means British Thermal Units.

"CEGT" means Centerpoint Energy Gas Transmission's East pipeline in Oklahoma.

"CEO" means Chief Executive Officer.

"CFO" means Chief Financial Officer.

"Company" refers to Panhandle Oil and Gas Inc.

"COO" means Chief Operating Officer.

"DD&A" means depreciation, depletion and amortization.

"ESOP" refers to the Panhandle Oil and Gas Inc. Employee Stock Ownership and 401(k) Plan, a tax qualified, defined contribution plan.

"FASB" means the Financial Accounting Standards Board.

"G&A" means general and administrative costs.

"Independent Consulting Petroleum Engineer(s)" or **"Independent Consulting Petroleum Engineering Firm"** refers to DeGolyer and MacNaughton of Dallas, Texas.

"LOE" means lease operating expense.

"Mcf" means thousand cubic feet.

"Mcfd" means thousand cubic feet per day.

"Mcfe" means natural gas stated on an Mcf basis and crude oil and natural gas liquids converted to a thousand cubic feet of natural gas equivalent by using the ratio of one Bbl of crude oil or natural gas liquids to six Mcf of natural gas.

"Mmbtu" means million BTU.

"Mmcf" means million cubic feet.

"Mmcfe" means natural gas stated on an Mmcf basis and crude oil and natural gas liquids converted to a million cubic feet of natural gas equivalent by using the ratio of one thousand Bbl of crude oil or natural gas liquids to six Mmcf of natural gas.

"minerals", **"mineral acres"** or **"mineral interests"** refer to fee mineral acreage owned in perpetuity by the Company.

"NGL" means natural gas liquids.

"NYMEX" refers to the New York Mercantile Exchange.

"OPEC" refers to the Organization of Petroleum Exporting Countries.

"Panhandle" refers to Panhandle Oil and Gas Inc.

"PDP" means proved developed producing.

"PEPL" means Panhandle Eastern Pipeline Company's Texas/Oklahoma mainline.

"play" is a term applied to identified areas with potential oil, NGL and/or natural gas reserves.

"PUD" means proved undeveloped.

"PV-10" means estimated pre-tax present value of future net revenues discounted at 10% using SEC rules.

"royalty interest" refers to well interests in which the Company does not pay a share of the costs to drill, complete and operate a well, but receives a much smaller proportionate share (as compared to a working interest) of production.

"SEC" refers to the United States Securities and Exchange Commission.

"working interest" refers to well interests in which the Company pays a share of the costs to drill, complete and operate a well and receives a proportionate share of production.

Fiscal year references

All references to years in this report, unless otherwise noted, refer to the Company's fiscal year end of September 30. For example, references to 2012 mean the fiscal year ended September 30, 2012.

References to natural gas

References to 2010 natural gas reserves, production, sales and prices include associated NGL.

References to oil and natural gas properties inherently include NGL associated with such properties.

PART I

ITEM 1 BUSINESS

GENERAL

Panhandle Oil and Gas Inc. was founded in Range, Texas County, Oklahoma, in 1926, as Panhandle Cooperative Royalty Company and operated as a cooperative until 1979, when the Company merged into Panhandle Royalty Company, and its shares became publicly traded. On April 2, 2007, the Company's name was changed to Panhandle Oil and Gas Inc. The name change was made to clear up confusion as to whether the Company was a royalty trust. Panhandle has never been a royalty trust.

While operating as a cooperative, the Company distributed most of its net income to shareholders as cash dividends. Upon conversion to a public company in 1979, although still paying dividends, the Company began to retain a substantial part of its cash flow to participate with a working interest in the drilling of wells on its mineral acreage and to purchase additional mineral acreage. Several acquisitions of additional mineral acreage and small companies were made in the '80s and '90s, and the acquisition of Wood Oil Company, as a wholly owned subsidiary, was consummated in October 2001. Wood Oil Company was merged into Panhandle Oil and Gas Inc. effective July 1, 2011.

The Company is involved in the acquisition, management and development of non-operated oil and natural gas properties, including wells located on the Company's mineral and leasehold acreage. Panhandle's mineral and leasehold properties are located primarily in Arkansas, New Mexico, North Dakota, Oklahoma and Texas, with properties also located in several other states. The majority of the Company's oil, NGL and natural gas production is from wells located in Oklahoma and Arkansas.

In January 2006, the Company last split its Class A Common Stock on a two-for-one basis. In March 2007, the Company increased its authorized Class A Common Stock from 12 million shares to 24 million shares.

The Company's office is located at Grand Centre, Suite 300, 5400 N. Grand Blvd., Oklahoma City, OK 73112; telephone - (405) 948-1560; facsimile - (405) 948-2038. The Company's website is **www.panhandleoilandgas.com.**

The Company files periodic reports with the SEC on Forms 10-Q and 10-K. These forms, the Company's annual report to shareholders and current press releases are available free of charge through our website as soon as reasonably practicable after they are filed with the SEC or made available to the public. Also, the Company posts copies of its various corporate governance documents on the website. From time to time, the Company posts other important disclosures to investors in the "Press Release" or "Upcoming Events" section of the website, as allowed by SEC rules.

Materials filed with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet website at **www.sec.gov** that contains reports, proxy and information statements, and other information regarding the Company that has been filed electronically with the SEC, including this Form 10-K.

BUSINESS STRATEGY

Typically, most of Panhandle's revenues are derived from the production and sale of oil, NGL and natural gas (see Item 8 - "Financial Statements and Supplementary Data"). The Company's oil and natural gas properties, including its mineral acreage, leasehold acreage and working and royalty interests in producing wells are mainly in Oklahoma with other significant holdings in Arkansas, New Mexico, North Dakota and Texas (see Item 2 - "Properties"). Exploration and development of the Company's oil and natural gas properties are conducted in association with oil and natural gas exploration and production companies, primarily larger independent companies. The Company does not operate any of its oil and natural gas properties, but has been an active working interest participant for many years in wells drilled on the Company's mineral acres. The majority of the Company's recent drilling participations have been on properties in which the Company owns mineral acreage. Most of these wells are in unconventional plays located in Oklahoma, Arkansas and Texas.

PRINCIPAL PRODUCTS AND MARKETS

The Company's principal products, in order of revenue generated, are natural gas, crude oil and NGL. These products are sold to various purchasers, including pipeline and marketing companies, which service the areas where the Company's producing wells are located. Since the Company does not operate any of the wells in which it owns an interest, it relies on the operating expertise of numerous companies that operate wells in the areas where the Company owns interests. This includes expertise in the drilling and completion of new wells, producing well operations and, in most cases, the marketing or purchasing of production from the wells. Natural gas and NGL sales are principally handled by the well operator and are normally contracted on a monthly basis with third-party natural gas marketers and pipeline companies. Payment for natural gas and NGL sold is received by the Company from the well operator or the contracted purchaser. Crude oil sales are generally handled by the well operator and payment for oil sold is received by the Company from the well operator or from the crude oil purchaser.

Prices of oil, NGL and natural gas are dependent on numerous factors beyond the control of the Company, including competition, weather, international events and circumstances, supply and demand, actions taken by OPEC, and economic, political and regulatory developments. Since demand for natural gas is generally highest during winter months, prices received for the Company's natural gas production are subject to seasonal variations.

The Company enters into price risk management financial instruments (derivatives) to reduce the Company's exposure to short-term fluctuations in the price of oil and natural gas. The derivative contracts apply only to a portion of the Company's oil and natural gas production and provide only partial price protection against declines in oil and natural gas prices. These derivative contracts expose the Company to risk of financial loss and may limit the benefit of future increases in oil and natural gas prices. A more thorough discussion of these derivative contracts, including risk of financial loss, is contained in Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations."

COMPETITIVE BUSINESS CONDITIONS

The oil and natural gas industry is highly competitive, particularly in the search for new oil, NGL and natural gas reserves. Many factors affect Panhandle's competitive position and the market for its products, which are beyond its control. Some of these factors include the quantity and price of foreign oil imports; domestic supply of oil, NGL and natural gas; changes in prices received for oil, NGL and natural gas production; business and consumer demand for refined oil products, NGL and natural gas; and the effects of federal and state regulation of the exploration for, production of and sales of oil, NGL and natural gas. Changes in existing economic conditions, political developments, weather patterns and actions taken by OPEC and other oil-producing countries have a dramatic influence on the price Panhandle receives for its oil, NGL and natural gas production.

The Company does not operate any of the wells in which it has an interest; rather it relies on companies with greater resources, staff, equipment, research and experience for operation of wells both in the drilling and production phases. The Company's business strategy is to use its strong financial base and its mineral and leasehold acreage ownership, coupled with its own geologic and economic evaluations, either to elect to participate in drilling operations with these larger companies or to lease or farmout its mineral or leasehold acreage while retaining a royalty interest. This strategy allows the Company to compete effectively in drilling operations it could not undertake on its own due to financial and personnel limitations while maintaining low overhead costs.

SOURCES AND AVAILABILITY OF RAW MATERIALS

The existence of recoverable oil, NGL and natural gas reserves in commercial quantities is essential to the ultimate realization of value from the Company's mineral and leasehold acreage. These mineral and leasehold properties are essentially the raw materials to our business. The production and sale of oil, NGL and natural gas from the Company's properties are essential to provide the cash flow necessary to sustain the ongoing viability of the Company. The Company reinvests a portion of its cash flow to purchase oil and natural gas mineral and leasehold acreage to assure the continued availability of acreage with which to participate in exploration and development drilling operations and, subsequently, the production and sale of oil, NGL and natural gas. This participation in exploration, development and production activities and purchase of additional acreage is necessary to continue to supply the Company with the raw materials with which to generate additional cash flow. Mineral and leasehold acreage purchases are made from many owners. The Company does not rely on any particular companies or persons for the purchases of additional mineral and leasehold acreage.

MAJOR CUSTOMERS

The Company's oil, NGL and natural gas production is sold, in most cases, through its well operators to many different purchasers on a well-by-well basis. During 2013, sales through two separate well operators accounted for approximately 20% and 10% of the Company's total oil, NGL and natural gas sales. During 2012, sales through three separate well operators accounted for approximately 15%, 13% and 10% of the Company's total oil, NGL and natural gas sales. During 2011, sales through two separate well operators accounted for approximately 15% and 14% of the Company's total oil, NGL and natural gas sales. Generally, if one purchaser declines to continue purchasing the Company's production, several other purchasers can be located. Pricing is generally consistent from purchaser to purchaser.

PATENTS, TRADEMARKS, LICENSES, FRANCHISES AND ROYALTY AGREEMENTS

The Company does not own any patents, trademarks, licenses or franchises. Royalty agreements on wells producing oil, NGL and natural gas stemming from the Company's ownership of mineral acreage generate a portion of the Company's revenues. These royalties are tied to ownership of mineral acreage, and this ownership is perpetual, unless sold by the Company. Royalties are due and payable to the Company whenever oil, NGL or natural gas is produced and sold from wells located on the Company's mineral acreage.

REGULATION

All of the Company's well interests and non-producing properties are located onshore in the United States. Oil, NGL and natural gas production is subject to various taxes, such as gross production taxes and, in some cases, ad valorem taxes.

The State of Oklahoma and other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other regulations relating to the exploration for and production of oil, NGL and natural gas. These states also have regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties and the regulation of spacing, plugging and abandonment of wells. These regulations vary from state to state. As previously discussed, the Company relies on its well operators to comply with governmental regulations.

Various aspects of the Company's oil and natural gas operations are regulated by agencies of the federal government. Transportation of natural gas in interstate commerce is generally regulated by the Federal Energy Regulatory Commission ("FERC") pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 ("NGPA"). The intrastate transportation and gathering of natural gas (and operational and safety matters related thereto) may be subject to regulation by state and local governments.

FERC's jurisdiction over interstate natural gas sales was substantially modified by the NGPA under which FERC continued to regulate the maximum selling prices of certain categories of natural gas sold in "first sales" in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (the "Decontrol Act") deregulated natural gas prices for all "first sales" of natural gas. Because "first sales" include typical wellhead sales by producers, all natural gas produced from the Company's natural gas properties is sold at market prices, subject to the terms of any private contracts in effect. FERC's jurisdiction over natural gas transportation was not affected by the Decontrol Act.

Sales of natural gas are affected by intrastate and interstate natural gas transportation regulation. Beginning in 1985, FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. FERC intended these changes to foster competition by transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of natural gas transporters. As a result of the various omnibus rulemaking proceedings in the late 1980s and the individual pipeline restructuring proceedings of the early to mid-1990s, interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, FERC expanded the impact of open access regulations to intrastate commerce.

FERC has pursued other policy initiatives that have affected natural gas marketing. Most notable are: (1) permitting the large-scale divestiture of interstate pipeline-owned natural gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to the use of electronic bulletin boards and electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis; (4) further review of the role of the secondary market for released pipeline capacity and its relationship to open access service in the primary market; and (5) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services upon the pipeline's demonstration of lack of market control in the relevant service market.

As a result of these changes, sellers and buyers of natural gas have gained direct access to the particular pipeline services they need and are able to conduct business with a larger number of counter parties. These changes generally have improved the access to markets for natural gas while substantially increasing competition in the natural gas marketplace. The effect of future regulations by FERC and other regulatory agencies cannot be predicted.

Sales of oil are not regulated and are made at market prices. The price received from the sale of oil is affected by the cost of transporting it to market. Much of that transportation is through interstate common carrier pipelines. Effective January 1, 1995, FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. Over time, these regulations tend to increase the cost of transporting oil by interstate pipelines, although some annual adjustments may result in decreased rates for a given year. These regulations have generally been upheld on judicial review. Every five years, FERC will examine the relationship between the annual change in the applicable index and the actual cost changes experienced by the oil pipeline industry.

ENVIRONMENTAL MATTERS

As the Company is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local laws and regulations regarding environmental and ecological matters. Compliance with these laws and regulations may necessitate significant capital outlays; however, to date, the Company's cost of compliance has been immaterial. The Company does not believe the existence of these environmental laws, as currently written and interpreted, will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future events or changes in laws, or the interpretation of laws, governing our industry. Current discussions involving the governance of hydraulic fracturing in the future could have a material impact on the Company. Since the Company does not operate any wells in which it owns an interest, actual compliance with environmental laws is controlled by the well operators, with Panhandle being responsible for its proportionate share of the costs involved. As such, to its knowledge, the Company is not aware of any instances of non-compliance with existing laws and regulations. Absent an extraordinary event, any noncompliance is not likely to have a material adverse effect on the financial condition of the Company. Although the Company is not fully insured against all environmental risks, insurance coverage is maintained at levels which are customary in the industry.

EMPLOYEES

At September 30, 2013, Panhandle employed 21 people with five of the employees serving as executive officers. The President and CEO is also a director of the Company.

ITEM 1A RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating the Company's business and future prospects. If any of the following risk factors should occur, the Company's financial condition could be materially impacted and the holders of our securities could lose part or all of their investment in Panhandle. The risk factors described below are not exhaustive, and investors are encouraged to perform their own investigation with respect to the Company and its business. Investors should also read the other information in this Form 10-K, including the financial statements and related notes.

Uncertainty of economic conditions, worldwide and in the United States, may have a significant negative effect on operating results, liquidity and financial condition.

Effects of change in domestic and international economic conditions could include: (1) a decline in demand for oil, NGL and natural gas resulting in decreased oil, NGL and natural gas reserves due to curtailed drilling activity; (2) a decline in oil, NGL and natural gas prices; (3) risk of insolvency of well operators and oil, NGL and natural gas purchasers; (4) limited availability of certain insurance coverage; (5) limited access to derivative instruments; and (6) limited credit availability. A decline in reserves would lead to a decline in production, and either a production decline, or a decrease in oil, NGL and natural gas prices, would have a negative impact on the Company's cash flow, profitability and value.

Oil, NGL and natural gas prices are volatile. Volatility in these prices can adversely affect operating results and the price of the Company's common stock. This volatility also makes valuation of oil and natural gas producing properties difficult and can disrupt markets.

The supply of and demand for oil, NGL and natural gas impact the prices we realize on the sale of these commodities and, in turn, materially affect the Company's financial results. Oil, NGL and natural gas prices have historically been, and will likely continue to be, volatile. The prices for oil, NGL and natural gas are subject to wide fluctuation in response to a number of factors, including:

- worldwide economic conditions
- economic, political, regulatory and tax developments
- market uncertainty
- changes in the supply of and demand for oil, NGL and natural gas
- availability and capacity of necessary transportation and processing facilities
- commodity futures trading
- regional price differentials
- differing quality of oil produced (i.e., sweet crude versus heavy or sour crude)
- differing quality and NGL content of natural gas produced
- weather conditions
- the level of imports and exports of oil, NGL and natural gas
- political instability or armed conflicts in major oil and natural gas producing regions
- actions taken by OPEC
- competition from alternative sources of energy
- technological advancements affecting energy consumption and energy supply

Price volatility makes it difficult to budget and project the return on investment in exploration and development projects and to estimate with precision the value of producing properties that are owned or acquired by the Company. In addition, volatile prices often disrupt the market for oil and natural gas properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties. Revenues, results of operations, reserves and capital availability may fluctuate significantly as a result of variations in oil, NGL and natural gas prices and production performance.

Lower oil, NGL and natural gas prices may also trigger significant impairment write-downs on a portion of the Company's properties and negatively affect the Company's results of operations and its ability to borrow under its credit facility.

A substantial decline in oil, NGL and natural gas prices for a prolonged period of time would have a material adverse effect on the Company.

The Company's financial position, results of operations, access to capital and the quantities of oil, NGL and natural gas that may be economically produced would be negatively impacted if oil, NGL and natural gas prices decrease significantly for an extended period of time. The ways in which such price decreases could have a material negative effect include:

- cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves and maintain or increase production
- future undiscounted and discounted net cash flows from producing properties would decrease, possibly resulting in impairment expense that may be significant
- certain reserves may no longer be economic to produce, leading to lower proved reserves, production and cash flow
- access to sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable

The Company cannot control activities on properties it does not operate.

The Company does not operate any of the properties in which it has an interest and has very limited ability to exercise influence over the third-party operators of these properties. Our dependence on the third-party operators of our properties, and on the cooperation of other working interest owners in these properties, could negatively affect the following:

- the Company's return on capital used in drilling or property acquisition
- the Company's production and reserve growth rates
- capital required to drill and complete wells
- success and timing of drilling, development and exploitation activities on the Company's properties
- compliance with environmental, safety and other regulations
- lease operating expenses
- plugging and abandonment costs, including well-site restorations

Dependency on each operator's judgment, expertise and financial resources could result in unexpected future costs, lost revenues and/or capital restrictions to the extent they would cumulatively have a material adverse effect on the Company's financial position and results of operations.

The Company's derivative activities may reduce the cash flow received for oil and natural gas sales.

In order to manage exposure to price volatility on our oil and natural gas production, we enter into oil and natural gas derivative contracts for a portion of our expected production. Oil and natural gas price derivatives may limit the cash flow we actually realize and therefore reduce the Company's ability to fund future projects. None of our oil and natural gas price derivative contracts are designated as hedges for accounting purposes; therefore, we record all derivative contracts at fair value on our balance sheet. Accordingly, these fair values may vary significantly from period to period, materially affecting reported earnings. The fair value of our oil and natural gas derivative instruments outstanding as of September 30, 2013, was a net asset of $425,198.

There is risk associated with our derivative contracts that involves the possibility that counterparties may be unable to satisfy contractual obligations to us. If any counterparty to our derivative instruments were to default or seek bankruptcy protection, it could subject a larger percentage of our future oil and natural gas production to commodity price changes and could have a negative effect on our ability to fund future projects.

There are also risks of financial loss associated with derivative instruments if there is an increase in the differential between the underlying price of the derivative contract and the actual received price.

A more thorough discussion of these derivative contracts, including risk of financial loss, is contained in Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Lower oil, NGL and natural gas prices or negative adjustments to oil, NGL and natural gas reserves may result in significant impairment charges.

The Company has elected to utilize the successful efforts method of accounting for its oil and natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and development dry holes are capitalized and amortized by property using the unit-of-production method (the ratio of oil, NGL and natural gas volumes produced to total proved or proved developed reserves) as oil, NGL and natural gas are produced.

All long-lived assets, principally the Company's oil and natural gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset on our books may be greater than its future net cash flows. The need to test a property for impairment may result from declines in oil, NGL and natural gas sales prices or unfavorable adjustments to oil, NGL and natural gas reserves. Also, once assets are classified as held for sale, they are reviewed for impairment. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded. If an impairment charge is recognized, cash flow from operating activities is not impacted, but net income and, consequently, shareholders' equity are reduced. In periods when impairment charges are incurred, it could have a material adverse effect on our results of operations.

Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

It is not possible to measure underground accumulations of oil, NGL and natural gas with precision. Oil, NGL and natural gas reserve engineering requires subjective estimates of underground accumulations of oil, NGL and natural gas using assumptions concerning future prices of these commodities, future production levels, and operating and development costs. In estimating our reserves, we and our Independent Consulting Petroleum Engineering Firm make various assumptions with respect to many subject matters that may prove to be incorrect, including:

- future oil, NGL and natural gas prices
- production rates
- reservoir pressures, decline rates, drainage areas and reservoir limits
- interpretation of subsurface conditions including geological and geophysical data
- potential for water encroachment or mechanical failures
- levels and timing of capital expenditures, lease operating expenses, production taxes and income taxes, and availability of funds for such expenditures
- effects of government regulation

If these assumptions prove to be incorrect, our estimates of reserves, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly.

Our standardized measure of oil and natural gas reserves is calculated using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month individual product prices for each month within the 12-month period prior to September 30 held flat over the life of the properties and operating costs in effect as of the date of estimation, less future estimated development, production and income tax expenses, and is discounted at 10% per annum to reflect the timing of future net revenue in accordance with the rules and regulations of the SEC. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates made for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates and the timing of development expenditures. Further, our lack of knowledge of all individual well information known to the well operators such as incomplete well stimulation efforts, restricted production rates for various reasons and up to date well production data, etc. may cause differences in our reserve estimates.

Because PUD's, under SEC reporting rules, may only be recorded if the wells they relate to are scheduled to be drilled within five years of the date of recording, the removal of PUD's that are not developed within this five year period may be required. Removals of this nature may significantly reduce the quantity and present value of the Company's oil, NGL and natural gas reserves.

Because forward-looking prices and costs are not used to estimate discounted future net cash flows from our estimated proved reserves, the standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil, NGL and natural gas reserves.

The timing of both our production and our incurrence of expenses in connection with the development and production of our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor used when calculating discounted future net cash flows in compliance with the FASB statement on oil and natural gas producing activities disclosures may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company, or the oil and natural gas industry in general.

Failure to find or acquire additional reserves will cause reserves and production to decline materially from their current levels.

The rate of production from oil and natural gas properties generally declines as reserves are depleted. The Company's proved reserves will decline materially as reserves are produced except to the extent that the Company acquires additional properties containing proved reserves, conducts additional successful exploration and development drilling, successfully applies new technologies or identifies additional behind-pipe zones (different productive zones within existing producing well bores) or secondary recovery reserves.

Drilling for oil and natural gas invariably involves unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient reserves to return a profit after deducting drilling, operating and other costs. In addition, wells that are profitable may not achieve a targeted rate of return. The Company relies on third-party operators' interpretation of seismic data and other advanced technologies in identifying prospects and in conducting exploration and development activities. Nevertheless, prior to drilling a well, the seismic data and other technologies used do not allow operators to know conclusively whether oil, NGL or natural gas is present in commercial quantities.

Cost factors can adversely affect the economics of any project, and ultimately the cost of drilling, completing and operating a well is controlled by well operators and existing market conditions. Further, drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions
- title problems
- pressure or irregularities in formations
- equipment failures or accidents
- fires, explosions, blowouts and surface cratering
- lack of availability to market production via pipelines or other transportation
- adverse weather conditions
- environmental hazards or liabilities
- governmental regulations

- cost and availability of drilling rigs, equipment and services
- expected sales price to be received for oil, NGL or natural gas produced from the wells

Oil and natural gas drilling and producing operations involve various risks.

The Company is subject to all the risks normally incident to the operation and development of oil and natural gas properties, including:

- well blowouts, cratering, explosions and human related accidents
- mechanical, equipment and pipe failures
- adverse weather conditions and natural disasters
- civil disturbances and terrorist activities
- oil, NGL and natural gas price reductions
- environmental risks stemming from the use, production, handling and disposal of water, waste materials, hydrocarbons and other substances into the air, soil or water
- title problems
- limited availability of financing
- marketing related infrastructure, transportation and processing limitations
- regulatory compliance issues

As a non-operator, we are dependent on third-party operators and the contractors they hire for operational safety, environmental safety and compliance with regulations of governmental authorities.

The Company maintains insurance against many potential losses or liabilities arising from well operations in accordance with customary industry practices and in amounts believed by management to be prudent. However, this insurance does not protect the Company against all risks. For example, the Company does not maintain insurance for business interruption, acts of war or terrorism. Additionally, pollution and environmental risks generally are not fully insurable. These risks could give rise to significant uninsured costs that could have a material adverse effect on the Company's business condition and financial results.

Debt level and interest rates may adversely affect our business.

The Company has a credit facility with Bank of Oklahoma (BOK) which consists of a revolving loan with a limit in the amount of $80,000,000. As of September 30, 2013, the Company had a balance of $8,262,256 drawn on the facility. The facility has a current borrowing base of $35,000,000, is secured by certain of the Company's properties and contains certain restrictive covenants.

Should the Company incur substantial indebtedness under its credit facility to fund capital projects or for other reasons, there is risk of it adversely affecting our business operations as follows:

- cash flows from operating activities required to service indebtedness may not be available for other purposes
- covenants contained in the Company's borrowing agreement may limit our ability to borrow additional funds, pay dividends and make certain investments
- any limitation on the borrowing of additional funds may affect our ability to fund capital projects and may also affect how we will be able to react to economic and industry changes
- a significant increase in the interest rate on our credit facility will limit funds available for other purposes
- changes in prevailing interest rates may affect the Company's capability to meet its debt service requirements, as its credit facility bears interest at floating rates

The borrowing base of our corporate revolving bank credit facility is subject to periodic redetermination and is based in part on oil, NGL and natural gas prices. A lowering of our borrowing base because of lower oil, NGL or natural gas prices, or for other reasons, could require us to repay indebtedness in excess of the newly established borrowing base, or we might need to further secure the debt with additional collateral. Our ability to meet any debt obligations depends on our future performance. General business, economic, financial and product pricing conditions, along with other factors, affect our future performance, and many of these factors are beyond our control. In addition, our failure to comply with the restrictive covenants relating to our credit facility could result in a default, which could adversely affect our business, financial condition and results of operations.

Future legislative or regulatory changes may result in increased costs and decreased revenues, cash flows and liquidity.

Companies that operate wells in which Panhandle owns a working interest are subject to extensive federal, state and local regulation. Panhandle, as a working interest owner, is therefore indirectly subject to these same regulations. New or changed laws and regulations such as those described below could have a material adverse effect on our business.

Federal Income Taxation

Proposals to repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses, if enacted, would increase and accelerate the Company's payment of federal income taxes. As a result, these changes would decrease the Company's cash flows available for developing its oil and natural gas properties.

Hydraulic Fracturing

The vast majority of oil and natural gas wells drilled in recent years have been, and future wells are expected to be, hydraulically fractured as a part of the process of completing the wells and putting them on production. This is true of the wells drilled in which the Company owns an interest. Hydraulic fracturing is a process that involves pumping water, sand and additives at high pressure into rock formations to stimulate oil and natural gas production. In developing plays where hydraulic fracturing, which requires large volumes of water, is necessary for successful development, the demand for water may exceed the supply. A lack of readily available water or a significant increase in the cost of water could cause delays or increased completion costs.

In addition to water, hydraulic fracturing fluid contains chemical additives designed to optimize production. Well operators are being required in certain states to disclose the components of these additives. Additional states and the federal government may follow with similar requirements or may restrict the use of certain additives. This could result in more costly or less effective development of wells.

Efforts to regulate hydraulic fracturing are increasing at the local, state and federal level. Several new regulations are being considered, including limiting water withdrawals and usage, limiting water disposition, restricting which additives may be used, implementing state-wide hydraulic fracturing moratoriums and temporary or permanent bans in certain environmentally sensitive areas. Public sentiment against hydraulic fracturing and shale gas production has become more vocal, which could result in more stringent permitting and compliance requirements. Consequences of these actions could potentially increase capital, compliance and operating costs significantly, as well as delay or halt the further development of oil and gas reserves on the Company's properties.

Any of the above factors could have a material adverse effect on our financial position, results of operations or cash flows.

Climate Change

Studies have suggested that emission of certain gases, commonly referred to as "greenhouse gases," may be impacting the earth's climate. Methane, a primary component of natural gas, and carbon dioxide, a by-product of burning oil and natural gas, are examples of greenhouse gases. The U.S. Congress and various states have been evaluating, and in some cases implementing, climate-related legislation and other regulatory initiatives that restrict emissions of greenhouse gases. In December 2009, the Environmental Protection Agency (EPA) issued findings that methane and carbon dioxide present a health and safety issue such that they should be regulated under the Clean Air Act.

In November 2010, the EPA finalized its greenhouse gas reporting requirements for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule requires annual reporting to the EPA of greenhouse gas emissions by such regulated facilities.

On April 17, 2012, the EPA issued final rules that established new air emission controls for crude oil and natural gas production and natural gas processing operations. The final rules require the use of reduced emission completions or "green completions" on all hydraulically-fractured wells completed or re-fractured after January 1, 2015. These rules may require the installation of new equipment to control emissions and other modifications by the third-party operators of wells in which we own an interest. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs.

These and any further restrictions resulting from federal or state legislation or regulations may have an effect on our ability to produce oil and natural gas, as well as the demand for oil, NGL and natural gas. Such changes may result in additional compliance obligations that could cumulatively have a material adverse effect on our financial condition, financial results and cash flows.

Shortages of oilfield equipment, services, qualified personnel and resulting cost increases could adversely affect results of operations.

The demand for qualified and experienced field personnel, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, NGL and natural gas prices, resulting in periodic shortages. When demand for rigs and equipment increases due to an increase in the number of wells being drilled, there have been shortages of drilling rigs, hydraulic fracturing equipment and personnel and other oilfield equipment. Higher oil, NGL and natural gas prices generally stimulate increased demand for, and result in increased prices of, drilling rigs, crews and associated supplies, equipment and services. These shortages or price increases could negatively affect the ability to drill wells and conduct ordinary operations by the operators of the Company's wells, resulting in an adverse effect on the Company's financial condition, cash flow and operating results.

Competition in the oil and natural gas industry is intense, and most of our competitors have greater financial and other resources than we do.

We compete in the highly competitive areas of oil and natural gas acquisition, development, exploration and production. We face intense competition from both major and independent oil and natural gas companies to acquire desirable producing properties, new properties for future exploration and human resource expertise necessary to effectively develop properties. We also face similar competition in obtaining sufficient capital to maintain drilling rights in all drilling units.

A substantial number of our competitors have financial and other resources significantly greater than ours and some of them are fully integrated oil and natural gas companies. These companies are able to pay more for development prospects and productive oil and natural gas properties and are able to define, evaluate, bid for, purchase and subsequently drill a greater number of properties and prospects than our financial or human resources permit, potentially reducing our ability to participate in drilling on certain of our acreage as a working interest owner. Our ability to develop and exploit our oil and natural gas properties and to acquire additional quality properties in the future will depend upon our ability to successfully evaluate, select and acquire suitable properties and join in drilling with reputable operators in this highly competitive environment.

Significant capital expenditures are required to replace our reserves and conduct our business.

The Company funds acquisition, exploration, development and production activities primarily through cash flows from operations and, to a lesser extent, borrowings under its credit facility. The timing and amount of capital necessary to carry out these activities can vary significantly as a result of product price fluctuations, property acquisitions, drilling results and the availability of drilling rigs, equipment, well services and transportation capacity.

Cash flows from operations and access to capital are subject to a number of variables, including the Company's:

- amount of proved reserves
- volume of oil, NGL and natural gas produced
- received prices for oil, NGL and natural gas sold
- ability to acquire and produce new reserves
- ability to obtain financing

We may have limited ability to obtain the capital required to sustain our operations at current levels if our borrowing base under our credit facility is lowered as a result of decreased revenues, lower product prices, declines in reserves or for other reasons. Failure to sustain operations at current levels could have a material adverse effect on our financial condition, cash flow and results of operations.

We may be subject to information technology system failures, network disruptions, cyber-attacks or other breaches in data security.

Power, telecommunication or other system failures due to hardware or software malfunctions, computer viruses, vandalism, terrorism, natural disasters, fire, human error or by other means could significantly affect the Company's ability to conduct its business. Though we have implemented complex network security measures, stringent internal controls and maintain offsite backup of all crucial electronic data, there cannot be absolute assurance that a form of system failure or data security breach will not have a material adverse effect on our financial condition and operations results.

ITEM 1B UNRESOLVED STAFF COMMENTS

None

ITEM 2 PROPERTIES

At September 30, 2013, Panhandle's principal properties consisted of (1) perpetual ownership of 255,300 net mineral acres, held principally in Arkansas, New Mexico, North Dakota, Oklahoma, Texas and six other states; (2) leases on 18,331 net acres primarily in Oklahoma: and (3) working interests, royalty interests or both in 6,105 producing oil and natural gas wells and 53 wells in the process of being drilled or completed.

Consistent with industry practice, the Company does not have current abstracts or title opinions on all of its mineral acreage and, therefore, cannot be certain that it has unencumbered title to all of these properties. In recent years, a few insignificant challenges have been made against the Company's fee title to its acreage.

The Company pays ad valorem taxes on minerals owned in eleven states.

ACREAGE

Mineral Interests Owned

The following table of mineral acreage owned reflects, in each respective state, the number of net and gross acres, net and gross producing acres, net and gross acres leased, and net and gross acres open (unleased) as of September 30, 2013.

State	Net Acres	Gross Acres	Net Acres Producing (1)	Gross Acres Producing (1)	Net Acres Leased to Others (2)	Gross Acres Leased to Others (2)	Net Acres Open (3)	Gross Acres Open (3)
Arkansas	11,992	51,055	7,089	25,989	1,722	5,468	3,181	19,598
Colorado	8,217	39,080	-	-	-	-	8,217	39,080
Florida	3,832	8,212	-	-	-	-	3,832	8,212
Kansas	3,082	11,816	144	1,200	-	-	2,938	10,616
Montana	1,008	17,947	-	-	-	-	1,008	17,947
New Mexico	57,374	174,300	1,381	7,205	160	320	55,833	166,775
North Dakota	11,179	64,286	170	2,036	20	160	10,989	62,090
Oklahoma	113,568	952,072	41,336	332,851	4,152	31,675	68,080	587,546
South Dakota	1,825	9,300	-	-	-	-	1,825	9,300
Texas	43,196	360,349	8,412	74,337	1,225	5,099	33,559	280,913
Other	27	262	-	-	-	-	27	262
Total:	**255,300**	**1,688,679**	**58,532**	**443,618**	**7,279**	**42,722**	**189,489**	**1,202,339**

(1) "Producing" represents the mineral acres in which Panhandle owns a royalty or working interest in a producing well.
(2) "Leased" represents the mineral acres owned by Panhandle that are leased to third parties but not producing.
(3) "Open" represents mineral acres owned by Panhandle that are not leased or in production.

Leases

The following table reflects net mineral acres leased from others, lease expiration dates, and net leased acres held by production as of September 30, 2013.

State	Net Acres	Net Acres Expiring					Net Acres Held by Production
		2014	2015	2016	2017	2018	
Arkansas	1,738	118	91	-	27	4	1,498
Kansas	2,117	-	-	-	-	-	2,117
Oklahoma	12,873	233	20	-	-	-	12,620
Other	1,603	-	-	-	-	-	1,603
TOTAL	18,331	351	111	-	27	4	17,838

PROVED RESERVES

The following table summarizes estimates of proved reserves of oil, NGL and natural gas held by Panhandle as of September 30, 2013. All proved reserves are located onshore within the United States and are principally made up of small interests in 6,105 wells, which are predominately located in the Mid-Continent region. Other than this report, the Company's reserve estimates are not filed with any other federal agency.

	Barrels of Oil	Barrels of NGL	Mcf of Natural Gas	Mcfe
Net Proved Developed Reserves				
September 30, 2013	1,037,721	764,321	82,298,833	93,111,085
September 30, 2012	849,548	494,160	65,733,119	73,795,367
September 30, 2011	759,989	386,774	60,193,878	67,074,456
Net Proved Undeveloped Reserves				
September 30, 2013	605,582	851,805	49,990,334	58,734,656
September 30, 2012	222,771	294,582	47,780,937	50,885,055
September 30, 2011	83,749	404,874	41,644,106	44,575,844
Net Total Proved Reserves				
September 30, 2013	1,643,303	1,616,126	132,289,167	151,845,741
September 30, 2012	1,072,319	788,742	113,514,056	124,680,422
September 30, 2011	843,738	791,648	101,837,984	111,650,300

The 27.2 Bcfe increase in total proved reserves from 2012 to 2013 is a combination of the following factors:

- Negative performance revisions of 5.8 Bcfe, which consists of 8.8 Bcfe of positive proved developed revisions principally due to better than projected well performance attributable to properties in Arkansas and Oklahoma and 14.6 Bcfe of negative proved undeveloped revisions principally attributable to the removal of dry gas reserves which are no longer projected to be developed within 5 years from the date they were added to the proved undeveloped reserves.

- Positive pricing revisions of 3.4 Bcfe due to proved developed wells (3.1 Bcfe) and proved undeveloped locations (.3 Bcfe) reaching their economic limits later than previously projected, thus adding reserves, resulting from higher natural gas prices.

- Proved developed reserve additions of 8.1 Bcfe principally resulting from:

  a) The Company's participation in ongoing development of conventional oil, NGL and natural gas plays utilizing horizontal drilling, including the Cleveland and Granite Wash plays in western Oklahoma and the Texas Panhandle, as well as the Marmaton and Hogshooter Wash plays in western Oklahoma.

  b) The Company's participation in ongoing development of unconventional natural gas plays utilizing horizontal drilling, including the Arkansas Fayetteville Shale and, to a much lesser extent, the Southeastern Oklahoma Woodford Shale.

  c) The Company's participation in ongoing development of unconventional oil, NGL and natural gas plays utilizing horizontal drilling in the Anadarko Basin Woodford Shale and Ardmore Basin Woodford Shale in western and southern Oklahoma.

- PUD additions of 32.8 Bcfe principally in the Fayetteville Shale play in Arkansas, the Anadarko Basin Woodford Shale and Ardmore Basin Woodford Shale in western and southern Oklahoma and the Cleveland and Granite Wash plays in western Oklahoma and the Texas Panhandle, as well as the Marmaton and Hogshooter Wash plays in western Oklahoma. These additions are the result of reservoir delineation proved by continuing drilling and well performance data in each of the referenced plays.

- Property purchases of 1.7 Bcfe primarily in the Fayetteville Shale play in Arkansas.

- Production of 13.0 Bcfe.

The following details the changes in proved undeveloped reserves for 2013 (Mcfe):

Beginning proved undeveloped reserves	50,885,055
Proved undeveloped reserves transferred to proved developed	(12,124,203)
Revisions	(14,309,809)
Extensions and discoveries	32,806,004
Purchases	1,477,609
Ending proved undeveloped reserves	58,734,656

The beginning PUD reserves were 50.9 Bcfe. A total of 12.1 Bcfe (24% of the beginning balance) were transferred to proved developed producing during 2013. The 14.3 Bcfe of negative revisions to PUD reserves consist of a positive pricing revision of 0.3 Bcfe offset by a 14.6 Bcfe (29% of the beginning balance) negative performance revision in 2013 as the result of removal of dry gas reserves which are no longer projected to be developed within 5 years from the date they were added. A total of 26.7 Bcfe (53% of the beginning balance) of PUD reserves were moved out of the category during 2013 as either the result of being transferred to proved developed or removed because they were no longer projected to be developed within 5 years from the date they were added to the proved undeveloped reserves. Only 21 PUD locations from 2009, representing 1% of total 2013 PUD reserves remain in the PUD category. We anticipate that all the Company's PUD locations will be drilled and converted to PDP within five years of the date they were added. However, PUD locations and associated reserves which are no longer projected to be drilled within 5 years from the date they were added to the proved undeveloped reserves will be removed as revisions at the time that determination is made and in the event that there are undrilled PUD locations at the end of the five-year period, it is our intent to remove the reserves associated with those locations from our proved reserves as revisions.

The determination of reserve estimates is a function of testing and evaluating the production and development of oil and natural gas reservoirs in order to establish a production decline curve. The established production decline curves, in conjunction with oil and natural gas prices, development costs, production taxes and operating expenses, are used to estimate oil and natural gas reserve quantities and associated future net cash flows. As information is processed regarding the development of individual reservoirs and as market conditions change, over time estimated reserve quantities and future net cash flows will change as well. Estimated reserve quantities and future net cash flows are affected by changes in product prices. These prices have varied substantially in recent years and are expected to vary substantially from current pricing in the future.

In January 2010, the FASB updated its oil and natural gas estimation and disclosure requirements to align its requirements with the SEC's modernized oil and natural gas reporting rules, which were effective for annual reports on Form 10_K for fiscal years ending on or after December 31, 2009. The update included the following changes: (1) permitting use of new technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; (2) enabling companies to additionally disclose their probable and possible reserves to investors, in addition to their proved reserves; (3) allowing previously excluded resources, such as oil sands, to be classified as oil and natural gas reserves rather than mining reserves; (4) requiring companies to report the independence and qualifications of a preparer or auditor, based on current Society of Petroleum Engineers criteria; (5) requiring the filing of reports for companies that rely on a third party to prepare reserve estimates or conduct a reserve audit; and (6) requiring companies to report oil and natural gas reserves using an average price based upon the prior 12-month period, rather than year-end prices. The update was applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and was effective for entities with annual reporting periods ending on or after December 31, 2009. Effective September 30, 2010, the Company adopted the new requirements. See Note 11 to the financial statements in Item 8 - "Financial Statements and Supplementary Data" for disclosures regarding our oil and natural gas reserves.

Proved oil and natural gas reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations - prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves, which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection), are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserve estimate, if the extraction is by means not involving a well.

Undeveloped oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

The independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas, calculated the Company's oil, NGL and natural gas reserves as of September 30, 2013, 2012 and 2011 (see Exhibits 23 and 99).

The Company's net proved oil, NGL and natural gas reserves (including certain undeveloped reserves described above) are located onshore in the United States. All studies have been prepared in accordance with regulations prescribed by the Securities and Exchange Commission. The reserve estimates were based on economic and operating conditions existing at September 30, 2013, 2012 and 2011. Since the determination and valuation of proved reserves is a function of testing and estimation, the reserves presented should be expected to change as future information becomes available.

ESTIMATED FUTURE NET CASH FLOWS

Set forth below are estimated future net cash flows with respect to Panhandle's net proved reserves (based on the estimated units set forth above in Proved Reserves) for the year indicated, and the present value of such estimated future net cash flows, computed by applying a 10% discount factor as required by SEC rules and regulations. As of September 30, 2010, the Company adopted the SEC Rule, *Modernization of Oil and Gas Reporting Requirements*. In accordance with the SEC rule, the estimated future net cash flows were computed using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month individual product prices for each month within the 12-month period prior to September 30 held flat over the life of the properties and applied to future production of proved reserves less estimated future development and production expenditures for these reserves. The amounts presented are net of operating costs and production taxes levied by the respective states. Prices used for determining future cash flows from oil, NGL and natural gas as of September 30, 2013, 2012 and 2011 were as follows: $89.06/Bbl, $27.28/Bbl, $3.33/Mcf; $89.41/Bbl, $35.70/Bbl, $2.51/Mcf; $90.28/Bbl, $38.91/Bbl, $3.81/Mcf, respectively. These future net cash flows based on SEC pricing rules should not be construed as the fair market value of the Company's reserves. A market value determination would need to include many additional factors, including anticipated oil, NGL and natural gas price and production cost increases or decreases, which could affect the economic life of the properties.

Estimated Future Net Cash Flows

	9/30/2013	9/30/2012	9/30/2011
Proved Developed	$ 239,353,059	$ 165,036,044	$ 211,851,992
Proved Undeveloped	123,822,641	72,851,862	91,232,949
Income Tax Expense	(131,397,192)	(83,543,516)	(107,111,317)
Total Proved	$ 231,778,508	$ 154,344,390	$ 195,973,624

10% Discounted Present Value of Estimated Future Net Cash Flows

	9/30/2013	9/30/2012	9/30/2011
Proved Developed	$ 125,186,445	$ 87,587,058	$ 106,464,138
Proved Undeveloped	51,276,694	27,151,132	29,977,891
Income Tax Expense	(74,788,243)	(47,323,902)	(58,059,595)
Total Proved	$ 101,674,896	$ 67,414,288	$ 78,382,434

OIL, NGL AND NATURAL GAS PRODUCTION

The following table sets forth the Company's net production of oil, NGL and natural gas for the fiscal periods indicated.

	Year Ended 9/30/2013	Year Ended 9/30/2012	Year Ended 9/30/2011 (1)
Bbls - Oil	234,084	153,143	104,141
Bbls - NGL	111,897	98,714	*
Mcf - Natural Gas	10,886,329	9,072,298	8,297,657
Mcfe	12,962,215	10,583,440	8,922,503

(1) Natural gas production includes NGL volumes.

AVERAGE SALES PRICES AND PRODUCTION COSTS

The following tables set forth unit price and cost data for the fiscal periods indicated.

Average Sales Price	Year Ended 9/30/2013	Year Ended 9/30/2012	Year Ended 9/30/2011 (1)
Per Bbl, Oil	$ 91.56	$ 90.13	$ 88.00
Per Bbl, NGL	$ 27.67	$ 33.23	*
Per Mcf, Natural Gas	$ 3.31	$ 2.62	$ 4.13
Per Mcfe	$ 4.68	$ 3.86	$ 4.87

(1) Proceeds from the sale of NGL have been included in natural gas sales and are therefore included in the price per Mcf of natural gas.

* The Company reported NGL reserves for the first time in its 2011 year-end reserve report. Increased drilling activity over the last two years in several western Oklahoma plays which produce significant NGL has resulted in meaningful NGL reserves and production for the Company. These reserve and production increases necessitated inclusion of NGL in the 2011 year-end reserve calculation and 2012 production volumes. In quarters prior to 2012, all NGL sales revenues were included with natural gas sales revenues.

Average Production (lifting) Costs	Year Ended 9/30/2013	Year Ended 9/30/2012	Year Ended 9/30/2011
(Per Mcfe)			
Well Operating Costs (1)	$ 0.92	$ 0.86	$ 0.95
Production Taxes (2)	0.14	0.14	0.16
	$ 1.06	$ 1.00	$ 1.11

(1) Includes actual well operating costs, compression, handling and marketing fees paid on natural gas sales and other minor expenses associated with well operations.
(2) Includes production taxes only.

Approximately 30% of the Company's oil, NGL and natural gas revenue is generated from royalty payments received on its mineral acreage. Royalty interests bear no share of the operating costs on those producing wells.

GROSS AND NET PRODUCTIVE WELLS AND DEVELOPED ACRES

The following table sets forth Panhandle's gross and net productive oil and natural gas wells as of September 30, 2013. Panhandle owns either working interests, royalty interests or both in these wells. The Company does not operate any wells.

	Gross Working Interest Wells	Net Working Interest Wells	Gross Royalty Only Wells	Total Gross Wells
Oil	242	15.61	1,009	1,251
Natural Gas	1,796	85.11	3,058	4,854
Total	2,038	100.72	4,067	6,105

Panhandle's average interest in royalty interest only wells is 0.84%. Panhandle's average interest in working interest wells is 4.94% working interest and 4.80% net revenue interest.

Information on multiple completions is not available from Panhandle's records, but the number is not believed to be significant. With regard to Gross Royalty Only Wells, some of these wells are in multi-well unitized fields. In such cases, the Company's ownership in each unitized field is counted as one gross well as the Company does not have access to the actual well count in all of these unitized fields.

As of September 30, 2013, Panhandle owned 443,618 gross developed mineral acres and 58,532 net developed mineral acres. Panhandle has also leased from others 139,717 gross developed acres containing 17,838 net developed acres.

UNDEVELOPED ACREAGE

As of September 30, 2013, Panhandle owned 1,245,061 gross and 196,768 net undeveloped mineral acres, and leases on 6,923 gross and 493 net undeveloped acres.

DRILLING ACTIVITY

The following net productive development, exploratory and purchased wells and net dry development, exploratory and purchased wells in which the Company had either a working interest, a royalty interest or both were drilled and completed during the fiscal years indicated.

	Net Productive Working Interest Wells	Net Productive Royalty Interest Wells	Net Dry Working Interest Wells
Development Wells			
Fiscal years ended:			
September 30, 2013	7.405905	1.532470	0.003906
September 30, 2012	5.376408	1.225832	0.093438
September 30, 2011	2.573391	0.907650	0.062188
Exploratory Wells			
Fiscal years ended:			
September 30, 2013	-- 0 --	0.079589	0.048446
September 30, 2012	0.298974	0.090654	0.531250
September 30, 2011	0.510643	0.372957	0.007813
Purchased Wells			
Fiscal years ended:			
September 30, 2013	-- 0 --	0.218122	-- 0 --
September 30, 2012	4.300626	0.231430	-- 0 --
September 30, 2011	-- 0 --	0.235058	-- 0 --

PRESENT ACTIVITIES

The following table sets forth the gross and net oil and natural gas wells drilling or testing as of September 30, 2013, in which Panhandle owns either a working interest, a royalty interest or both. These wells were not producing at September 30, 2013.

	Gross Wells	Net Wells
Oil	26	0.91
Natural Gas	27	1.02

OTHER FACILITIES

The Company has a lease on 12,369 square feet for its office in Oklahoma City, Oklahoma, which ends April 30, 2015.

SAFE HARBOR STATEMENT

This report, including information included in, or incorporated by reference from, future filings by the Company with the SEC, as well as information contained in written material, press releases and oral statements, contains, or may contain, certain statements that are "forward-looking statements," within the meaning of the federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events or developments which are expected to, or anticipated will, or may, occur in the future, are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts" and similar expressions are used to identify forward-looking statements.

These forward-looking statements include, among others, such things as: the amount and nature of our future capital expenditures; wells to be drilled or reworked; prices for oil, NGL and natural gas; demand for oil, NGL and natural gas; estimates of proved oil, NGL and natural gas reserves; development and infill drilling potential; drilling prospects; business strategy; production of oil, NGL and natural gas reserves; and expansion and growth of our business and operations.

These statements are based on certain assumptions and analyses made by the Company in light of experience and perception of historical trends, current conditions and expected future developments as well as other factors believed appropriate in the circumstances. However, whether actual results and development will conform to our expectations and predictions is subject to a number of risks and uncertainties, which could cause actual results to differ materially from our expectations.

One should not place undue reliance on any of these forward-looking statements. The Company does not currently intend to update forward-looking information and to release publicly the results of any future revisions made to forward-looking statements to reflect events or circumstances, which reflect the occurrence of unanticipated events, after the date of this report.

In order to provide a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made, the following discussion outlines certain factors that in the future could cause results for 2014 and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of the Company.

Commodity Prices. The prices received for oil, NGL and natural gas production have a direct impact on the Company's revenues, profitability and cash flows as well as the ability to meet its projected financial and operational goals. The prices for crude oil, NGL and natural gas are dependent on a number of factors beyond the Company's control, including: the demand for oil, NGL and natural gas; weather conditions in the continental United States (which can greatly influence the demand for natural gas at any given time as well as the price we receive for such natural gas); and the ability of current distribution systems in the United States to effectively meet the demand for oil, NGL and natural gas at any given time, particularly in times of peak demand which may result because of adverse weather conditions.

Oil prices are sensitive to foreign influences based on political, social or economic factors, any one of which could have an immediate and significant effect on the price and supply of oil. In addition, prices of both natural gas and oil are becoming more and more influenced by trading on the commodities markets, which has, at times, increased the volatility associated with these prices.

Uncertainty of Oil, NGL and Natural Gas Reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond the Company's control. The oil, NGL and natural gas reserve data included in this report represents only an estimate of these reserves. Oil and natural gas reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil, NGL and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGL and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas and assumptions concerning future oil, NGL and natural gas prices, future operating costs, severance and excise taxes, development costs, and workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil, NGL and natural gas and estimates of the future net cash flows from oil, NGL and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, oil, NGL and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues and expenditures with respect to oil, NGL and natural gas reserves will vary from estimates, and those variances can be material.

The Company does not operate any of the properties in which it has an interest and has very limited ability to exercise influence over operations for these properties or their associated costs. Dependence on the operator and other working interest owners for these projects and the limited ability to influence operations and associated costs could materially and adversely affect the realization of targeted returns on capital in drilling or acquisition activities and targeted production growth rates.

The information regarding discounted future net cash flows included in this report is not necessarily the current market value of the estimated oil, NGL and natural gas reserves attributable to the Company's properties. As required by the SEC, the estimated discounted future net cash flows from proved oil, NGL and natural gas reserves are determined based on the fiscal year's 12-month average of the first-day-of-the-month individual product prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows are also affected, in part, by the amount and timing of oil, NGL and natural gas production, supply and demand for oil, NGL and natural gas and increases or decreases in consumption.

In addition, the 10% discount factor required by the SEC used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and the risks associated with operations of the oil and natural gas industry in general.

ITEM 3 LEGAL PROCEEDINGS

There were no material legal proceedings involving Panhandle on September 30, 2013, or at the date of this report.

ITEM 4 MINE SAFETY DISCLOSURES

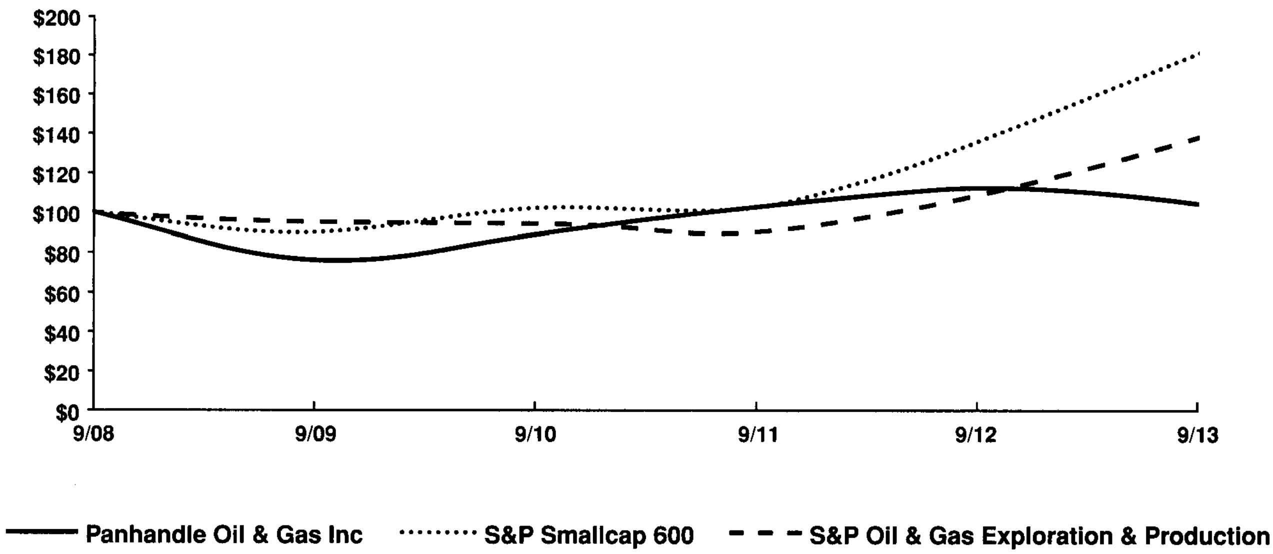
Not applicable.

PART II

ITEM 5 MARKET FOR COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Panhandle Oil & Gas Inc, the S&P Smallcap 600 Index, and the S&P Oil & Gas Exploration & Production Index



*$100 invested on 9/30/08 in stock or index, including reinvestment of dividends.
Fiscal year ending September 30.

The above graph compares the 5-year cumulative total return provided shareholders on our Class A Common Stock ("Common Stock") relative to the cumulative total returns of the S&P Smallcap 600 Index and the S&P Oil & Gas Exploration & Production Index. An investment of $100 (with reinvestment of all dividends) is assumed to have been made in our Common Stock and in each of the indexes on September 30, 2008, and its relative performance is tracked through September 30, 2013.

Since July 22, 2008, the Company's Common Stock has been listed and traded on the New York Stock Exchange (symbol PHX). The following table sets forth the high and low trade prices of the Common Stock during the periods indicated:

Quarter Ended	High	Low
December 31, 2011	$ 36.00	$ 26.18
March 31, 2012	$ 33.74	$ 28.05
June 30, 2012	$ 30.57	$ 24.16
September 30, 2012	$ 33.49	$ 27.85
December 31, 2012	$ 31.70	$ 24.70
March 31, 2013	$ 30.63	$ 26.83
June 30, 2013	$ 31.12	$ 27.00
September 30, 2013	$ 32.86	$ 27.27

At November 25, 2013, there were 1,474 holders of record of Panhandle's Class A Common Stock and approximately 3,700 beneficial owners.

During the past two years, the Company has paid quarterly dividends of $.07 per share on its Common Stock. Approval by the Company's Board is required before the declaration and payment of any dividends.

While the Company anticipates it will continue to pay dividends on its Common Stock, the payment and amount of future cash dividends will depend upon, among other things, financial condition, funds from operations, the level of capital and development expenditures, future business prospects, contractual restrictions and any other factors considered relevant by the Board.

The Company's credit facility also contains a provision limiting the paying or declaring of a cash dividend during any fiscal year to 20% of net cash flow provided by operating activities from the Statement of Cash Flows of the preceding 12-month period. See Note 4 to the financial statements in Item 8 - "Financial Statements and Supplementary Data" for a further discussion of the credit facility.

Upon approval by the shareholders of the Company's 2010 Restricted Stock Plan on March 11, 2010, the Board approved the purchase of the Company's Common Stock, from time to time, equal to the aggregate number of shares of Common Stock awarded pursuant to the Company's 2010 Restricted Stock Plan, contributed by the Company to its ESOP and credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors. The Board's approval included an initial authorization to purchase up to $1.5 million of Common Stock, with a provision for subsequent authorizations without specific action by the Board. As the amount of Common Stock purchased under any authorization reaches $1.5 million, another $1.5 million is automatically authorized for Common Stock purchases unless the Board determines otherwise. Pursuant to these resolutions adopted by the Board, the purchase of additional $1.5 million increments of the Company's Common Stock became authorized and approved effective March 29, 2011, March 14, 2012, and June 26, 2013. The shares are held in treasury and are accounted for using the cost method. There were no Common Stock purchases in the fourth quarter of fiscal year 2013. At September 30, 2013, and September 30, 2012, 10,907 and 10,660 (respectively) treasury shares were contributed to the Company's ESOP on behalf of the ESOP participants.

ITEM 6 SELECTED FINANCIAL DATA

The following table summarizes financial data of the Company for its last five fiscal years and should be read in conjunction with Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Financial Statements of the Company, including the Notes thereto, included elsewhere in this report.

	As of and for the year ended September 30,				
	2013	2012	2011	2010	2009
Revenues					
Oil, NGL and natural gas sales	$ 60,605,878	$ 40,818,434	$ 43,469,130	$ 44,068,947	$ 37,421,688
Lease bonuses and rentals	938,846	7,152,991	352,757	1,120,674	188,906
Gains (losses) on derivative contracts	611,024	73,822	734,299	6,343,661	(661,828)
Income from partnerships	733,372	487,070	420,465	405,134	323,848
	62,889,120	48,532,317	44,976,651	51,938,416	37,272,614
Costs and expenses					
Lease operating expense	11,861,403	9,141,970	8,441,754	8,193,319	7,696,026
Production taxes	1,834,840	1,449,537	1,456,755	1,446,545	1,201,209
Exploration costs	9,795	979,718	1,025,542	1,583,773	711,582
Depreciation, depletion and amortization	21,945,768	19,061,239	14,712,188	19,222,123	28,168,933
Provision for impairment	530,670	826,508	1,728,162	605,615	2,464,520
Loss (gain) on asset sales, int. & other	(785,401)	39,493	(68,325)	(1,028,148)	(2,677,407)
Gen. and administrative	6,801,996	6,388,856	5,994,663	5,594,499	4,866,044
Bad debt expense (recovery)	-	-	-	-	(185,272)
	42,199,071	37,887,321	33,290,739	35,617,726	42,245,635
Income (loss) before provision (benefit) for income taxes	20,690,049	10,644,996	11,685,912	16,320,690	(4,973,021)
Provision (benefit) for income taxes	6,730,000	3,274,000	3,192,000	4,901,000	(2,568,000)
Net income (loss)	$ 13,960,049	$ 7,370,996	$ 8,493,912	$ 11,419,690	$ (2,405,021)
Basic and diluted earnings (loss) per share	$ 1.67	$ 0.88	$ 1.01	$ 1.36	$ (0.29)
Dividends declared per share	$ 0.28	$ 0.28	$ 0.28	$ 0.28	$ 0.28
Weighted average shares outstanding					
Basic and diluted	8,356,904	8,360,931	8,393,890	8,422,387	8,397,337
Net cash provided by (used in):					
Operating activities	$ 37,402,109	$ 25,371,195	$ 29,283,929	$ 27,806,475	$ 37,710,606
Investing activities	$ (26,364,675)	$ (38,288,959)	$ (27,200,816)	$ (9,845,516)	$ (36,322,992)
Financing activities	$ (10,154,362)	$ 11,394,864	$ (4,173,372)	$ (13,003,609)	$ (1,643,414)
Total assets	$ 147,838,430	$ 135,186,730	$ 111,424,193	$ 105,124,839	$ 108,549,632
Long-term debt	$ 8,262,256	$ 14,874,985	$ -	$ -	$ 10,384,722
Shareholders' equity	$ 95,655,486	$ 83,852,146	$ 78,802,317	$ 73,581,996	$ 64,122,343

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

BUSINESS OVERVIEW

The Company's principal line of business is to explore for, develop, produce and sell oil, NGL and natural gas. Results of operations are dependent primarily upon: reserve quantities and associated exploration and development costs in finding new reserves; production quantities and related production costs; and oil, NGL and natural gas sales prices.

Natural gas production was 20% higher in 2013 than in 2012. This production increase is the combined effect of added natural gas production from wells put on production during the first half of 2013 in the Fayetteville Shale and associated natural gas production from ongoing development on the Company's mineral and leasehold acreage in the following oil and NGL rich plays:

- Horizontal Granite Wash and Hogshooter in western Oklahoma and the Texas Panhandle
- Horizontal Cleveland in western Oklahoma and the Texas Panhandle
- Horizontal Marmaton in western Oklahoma
- Horizontal Tonkawa in western Oklahoma
- Horizontal Anadarko Basin Woodford Shale in western Oklahoma
- Horizontal Ardmore Basin Woodford Shale in southern Oklahoma

Development in these plays has also resulted in a 53% and a 13% increase in 2013 oil and NGL production, respectively, as compared to 2012.

As of September 30, 2013, the Company owned an average 3.6% net revenue interest in 53 wells that were drilling or testing. As these wells begin producing and other scheduled wells are drilled and completed in the abovementioned plays, the Company anticipates fiscal 2014 oil and NGL production will increase over that of 2013, while 2014 natural gas production is expected to remain relatively flat to 2013.

The increased production of oil, NGL and natural gas in 2013, and higher natural gas and oil prices, partially offset by lower NGL prices, resulted in a 48% increase in revenues from the sale of oil, NGL and natural gas. Based on recent forward strip pricing for 2014, the Company expects 2014 average natural gas prices to be slightly higher (approximately $3.40 per Mcf), oil prices to be lower (approximately $88.00 per Bbl) and NGL prices to remain flat (approximately $28.00 per Bbl) to their corresponding average prices in 2013.

The Company's proved developed oil, NGL and natural gas reserves increased in 2013, compared to 2012, by 19.3 Bcfe, or 26%. The increase is due primarily to successful drilling activities.

Management currently expects drilling on the Company's acreage to result in capital expenditures for oil and natural gas activities of approximately $33 million during 2014. The Company will also continue to evaluate opportunities to acquire mineral acreage or producing properties. Acquisitions, if any, will be financed by a combination of available cash and the bank credit facility.

The Company had no off balance sheet arrangements during 2013 or prior years.

The following table reflects certain operating data for the periods presented:

	For the Year Ended September 30,				
	2013	Percent Incr. or (Decr.)	2012	Percent Incr. or (Decr.)	2011
Production:					
Oil (Bbls)	234,084	53%	153,143	47%	104,141
NGL (Bbls)	111,897	13%	98,714	-	*
Natural Gas (Mcf)	10,886,329	20%	9,072,298	9%	8,297,657
Mcfe	12,962,215	22%	10,583,440	19%	8,922,503
Average Sales Price:					
Oil (per Bbl)	$ 91.56	2%	$ 90.13	2%	$ 88.00
NGL (per Bbl)	$ 27.67	-17%	$ 33.23	-	*
Natural Gas (Mcf) (1)	$ 3.31	26%	$ 2.62	-37%	$ 4.13
Mcfe	$ 4.68	21%	$ 3.86	-21%	$ 4.87

(1) Proceeds from the sale of NGL in 2011 were included in natural gas sales, and were therefore included in the price per Mcf of natural gas.

* The Company reported NGL reserves for the first time in its 2011 year-end reserve report. Increased drilling activity over the last few years in several western Oklahoma plays which produce significant NGL has resulted in meaningful NGL reserves and production for the Company. These reserve and production increases necessitated inclusion of NGL in the 2011 year-end reserve calculation and 2012 production volumes. In quarters prior to 2012, all NGL sales revenues were included with natural gas sales revenues.

RESULTS OF OPERATIONS

Fiscal Year 2013 Compared to Fiscal Year 2012

Overview

The Company recorded net income of $13,960,049, or $1.67 per share, in 2013, compared to net income of $7,370,996, or $0.88 per share, in 2012. Revenues increased in 2013 primarily due to higher oil and natural gas sales volumes and prices, partially offset by decreased lease bonuses received.

Expenses increased due to higher DD&A, LOE and G&A in 2013, partially offset by decreases in the provision for impairment and exploration costs and increases in other miscellaneous income. Significant well additions, through drilling, in 2013 increased production volumes, resulting in higher DD&A and LOE in 2013.

Oil, NGL and Natural Gas Sales

Oil, NGL and natural gas sales increased $19,787,444 or 48% for 2013, as compared to 2012. The increase was due to increased oil volumes of 53%, increased natural gas volumes of 20%, increased natural gas prices of 26% and a 2% increase in oil prices in 2013.

The oil and NGL production increase is primarily the result of horizontal drilling in the Marmaton/Cleveland, Hogshooter and Granite Wash in western Oklahoma, horizontal Cleveland drilling in the Texas Panhandle and horizontal Woodford Shale drilling in the Anadarko and Ardmore Basins in southern Oklahoma. To a lesser extent, focused drilling in the Permian Basin in West Texas, the Bakken in North Dakota and the Mississippian in northern Oklahoma contributed to the oil and NGL production increase. The natural gas production increase was primarily driven by horizontal development drilling in the Arkansas Fayetteville Shale and natural gas production associated with the aforementioned oil and NGL drilling activity.

Production by quarter for 2013 and 2012 was as follows (Mcfe):

	2013	2012
First quarter	3,008,365	2,559,524
Second quarter	3,245,411	2,654,485
Third quarter	3,229,800	2,649,351
Fourth quarter	3,478,639	2,720,080
Total	12,962,215	10,583,440

Lease Bonus and Rentals

Lease bonuses and rentals decreased $6,214,145 in 2013. The decrease was mainly due to the Company leasing partial rights on 2,743 net mineral acres in Roger Mills County, Oklahoma, for $4.8 million and leasing 2,431 net acres in the horizontal Mississippian play in northern Oklahoma for $1.7 million in 2012. There were no large leases of the Company's mineral acreage in 2013.

Gains (Losses) on Derivative Contracts

Realized and unrealized gains and losses are scheduled below:

Gains (Losses) on Derivative Contracts	2013	2012
Realized	$ 13,555	$ 462,033
Unrealized	597,469	(388,211)
Total	$ 611,024	$ 73,822

The increase in gains was mainly due to the natural gas collars and natural gas fixed price swaps being more beneficial in 2013, as NYMEX gas futures have fallen below the floor of the collars and the fixed gas prices of the swaps. As of September 30, 2013, the Company's natural gas fixed price swaps have expiration dates of October, November and December 2013; the natural gas costless collar contracts have expiration dates of December 2013 and April 2014; the oil costless collar contracts have expiration dates of December 2013 and June 2014 and the oil fixed price swaps have an expiration date of December 2013.

Lease Operating Expenses (LOE)

LOE increased $2,719,433 or 30% in 2013. LOE costs per Mcfe of production increased from $.86 in 2012 to $.92 in 2013. The total LOE increase is primarily related to increased field operating costs of $726,095 in 2013 compared to 2012. Field operating costs increased mainly due to the large addition in the number of wells drilled in 2013. Field operating costs were $.40 per Mcfe in 2013 compared to $.42 per Mcfe in 2012, a 5% decrease. This decrease in rate is principally the result of fewer well workovers performed in 2013.

The increase in LOE related to field operating costs was also coupled with an increase in handling fees (primarily gathering, transportation and marketing costs) on natural gas of $1,993,338 in 2013, as compared to 2012. On a per Mcfe basis, these fees were up $.07 due to higher natural gas prices. Handling fees are mainly charged as a percent of natural gas sales, but can also be charged based on natural gas production volumes.

Exploration Costs

Exploration costs were $9,795 in 2013, compared to $979,718 in 2012, a $969,923 decrease. During 2013, leasehold impairment and expired leasehold totaled $70,638, compared to $377,942 during 2012, a $307,304 decrease. The decline was driven by lower provisions for expected lease expirations in 2013, as compared to 2012. Charges on three exploratory dry holes totaled $601,776 during 2012; whereas, in 2013 the Company had no exploratory dry holes and received a net credit adjustment of $60,843 for exploratory dry hole costs incurred in previous years.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased $2,884,529 or 15% in 2013. DD&A per Mcfe was $1.69 in 2013, compared to $1.80 in 2012. DD&A increased $4,284,278 due to oil, NGL and natural gas production volumes increasing 22% in the 2013 period, compared to the 2012 period. An offsetting decrease of $1,399,749 was caused by an $.11 decrease in the DD&A rate. This rate decrease is principally due to positive performance and price revisions increasing ultimate reserves at September 30, 2013, for a significant number of wells.

Provision for Impairment

The provision for impairment decreased $295,838 in 2013, as compared to 2012. During 2013, impairment of $530,670 was recorded on five small fields in Oklahoma and Texas. These fields have one to a few wells and are more susceptible to impairment when a well in the field experiences downward reserve revisions, or when a newly completed well with low reserves is added to one of these fields. During the 2012 period, impairment of $826,508 was recorded on twelve small fields in Oklahoma.

Loss (Gain) on Asset Sales, Interest and Other

Loss (Gain) on Asset Sales, Interest and Other was a net gain of $785,401 in 2013, as compared to a net loss of $39,493 in 2012. The gain in 2013 was mainly the result of a class action lawsuit settlement of approximately $604,000 related to the underpayment of royalty revenues.

General and Administrative Costs (G&A)

G&A increased $413,140 or 6% in 2013. The increase is primarily related to increases in the following expense categories: personnel $442,013 and technical consulting $111,832. These were partially offset by decreases in legal fees, Board fees and other expenses of $140,705 in 2013. The increase in 2013 personnel related expenses was largely the result of restricted stock expense increases of $353,044. The increase in technical consulting in 2013 was principally due to increased engineering analysis to evaluate potential acquisitions. The decrease in legal expenses was a result of lower acquisition activity in 2013. The decrease in Board fees was the result of fewer members in 2013.

Provision (Benefit) for Income Taxes

The 2013 provision for income taxes of $6,730,000 was based on a pre-tax income of $20,690,049, as compared to a provision for income taxes of $3,274,000 in 2012, based on a pre-tax income of $10,644,996. The effective tax rate for 2013 was 33%, compared to an effective tax rate for 2012 of 31%. The 2013 effective tax rate increase of 2% was due to pre-tax income increasing 94% from 2012 to 2013, while the excess percentage depletion allowance (which is a permanent tax benefit) increased only 25% over the same period. This resulted in a greater proportion of pre-tax income being subject to income tax and thus increased the effective tax rate. The Company's utilization of excess percentage depletion decreases the provision for income taxes. The benefit of excess percentage depletion is not directly related to the amount of recorded income or loss. Accordingly, in cases where the recorded income or loss is relatively small, the proportional effect of the excess percentage depletion on the effective tax rate may become significant.

Fiscal Year 2012 Compared to Fiscal Year 2011

Overview

The Company recorded net income of $7,370,996, or $0.88 per share, in 2012, compared to net income of $8,493,912, or $1.01 per share, in 2011. Revenues increased in 2012 primarily due to increased lease bonuses and higher oil and natural gas sales volumes, partially offset by lower natural gas prices.

Expenses increased due to higher DD&A, LOE and G&A in 2012, partially offset by decreases in the provision for impairment and exploration costs. Significant well additions through acquisition and drilling in 2012 increased production volumes and lifting costs, resulting in higher DD&A and LOE in 2012.

Oil, NGL and Natural Gas Sales

Oil, NGL and natural gas sales revenues decreased $2,650,696 or 6% for 2012, as compared to 2011. The decrease was due to lower natural gas prices of 37%, partially offset by increased oil volumes of 47%, increased natural gas volumes of 9% and a 2% increase in oil prices in 2012.

The oil production increase was due to continued drilling in western Oklahoma oily plays such as the horizontal Granite Wash, Cleveland, Tonkawa, Marmaton, Anadarko Basin Woodford Shale and other plays in Oklahoma, West Texas, Texas Panhandle and southeastern New Mexico. The natural gas production increase was mainly a result of production attributable to the acquisition in the Fayetteville Shale in Arkansas that the Company completed effective October 25, 2011. As of September 30, 2012, the Company owned an average 3.6% net revenue interest in 62 wells that were drilling or testing.

Production by quarter for 2012 and 2011 was as follows (Mcfe):

	2012	2011
First quarter	2,559,524	2,208,218
Second quarter	2,654,485	2,152,011
Third quarter	2,649,351	2,129,160
Fourth quarter	2,720,080	2,433,114
Total	10,583,440	8,922,503

Lease Bonus and Rentals

Lease bonuses and rentals increased $6,800,234 in 2012. The increase was mainly due to the Company leasing 2,743 net mineral acres in Roger Mills County, Oklahoma, for $4.8 million. The rights leased were from the surface to 100 feet below the base of the Virgilian (commonly referred to as the Tonkawa). The Company also leased 2,431 net mineral acres in the horizontal Mississippian play in northern Oklahoma for $1.7 million. There were no large leases of the Company's mineral acreage in 2011.

Gains (Losses) on Derivative Contracts

Realized and unrealized gains and losses are scheduled below:

Gains (Losses) on Derivative Contracts	2012	2011
Realized	$ 462,033	$ 2,138,685
Unrealized	(388,211)	(1,404,386)
Total	$ 73,822	$ 734,299

The decrease in gains was mainly due to the natural gas basis protection swaps being less beneficial in 2012, as the basis differentials between NYMEX and CEGT and PEPL declined significantly. As of September 30, 2012, the Company's natural gas basis protection swaps had an expiration date of December 2012; the natural gas costless collar contracts had expiration dates of October 2012 and January 2013; the oil costless collar contracts had an expiration date of December 2012.

Lease Operating Expenses (LOE)

LOE increased $700,216 or 8% in 2012. LOE costs per Mcfe of production decreased from $.95 in 2011 to $.86 in 2012. The total LOE increase was primarily related to increased field operating costs of $487,388 in 2012 compared to 2011. Field operating costs increased mainly due to the large addition of wells through acquisition and drilling in 2012. Field operating costs were $.42 per Mcfe in 2012 compared to $.44 per Mcfe in 2011, a 5% decrease. This decrease in rate was principally the result of fewer well workovers performed in 2012.

The increase in LOE related to field operating costs was also coupled with an increase in handling fees (primarily gathering, transportation and marketing costs) on natural gas of $212,828 in 2012, as compared to 2011. On a per Mcfe basis, these fees were down $.06 due to lower natural gas prices and the addition of significant oil production, which is unencumbered by these fees. Handling fees are mainly charged as a percent of natural gas sales but can also be charged based on natural gas production volumes.

Exploration Costs

Exploration costs were $979,718 in 2012 compared to $1,025,542 in 2011, a $45,824 decrease. During 2012, leasehold impairment and expired leasehold totaled $377,942 compared to $482,491 during 2011, a $104,549 decrease. The decline was driven by lower provisions for expected lease expirations in 2012, as compared to 2011. Charges on three exploratory dry holes totaled $601,776 during 2012; whereas, in 2011 the Company incurred exploratory dry hole costs on two wells totaling $543,051.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased $4,349,051 or 30% in 2012. DD&A per Mcfe was $1.80 in 2012 compared to $1.65 in 2011. DD&A increased $2,738,695 due to oil, NGL and natural gas production volumes increasing 19% in the 2012 period compared to the 2011 period. The remaining increase of $1,610,356 was caused by a $.15 increase in the DD&A rate. This rate increase is mainly due to negative price revisions reducing ultimate reserves on a significant number of wells in reserves reported at September 30, 2012, as well as higher finding cost experienced in oil and liquids-rich areas where the Company is drilling and has had new wells come on line.

Provision for Impairment

The provision for impairment decreased $901,654 in 2012, as compared to 2011. During 2012, impairment of $826,508 was recorded on twelve small fields in Oklahoma. These fields have one to a few wells and are more susceptible to impairment when a well in the field experiences downward reserve revisions, or when a newly completed well with low reserves is added to one of these fields. During the 2011 period, impairment of $1,728,162 was recorded on nine small fields in Oklahoma and Texas.

General and Administrative Costs (G&A)

G&A increased $394,193 or 7% in 2012. The increase is primarily related to increases in the following expense categories: personnel $419,166 and legal fees $118,245. These were partially offset by decreases in technical consulting, Board fees, company insurance and other expenses of $143,218 in 2012. The increase in 2012 personnel related expenses was the result of additional employees and annual increases in salaries and bonuses totaling $206,806, restricted stock expense increase of $178,441 and higher ESOP expense of $25,475. The increase in legal expenses resulted from increased acquisition activity and a quiet title defense settlement in 2012.

Provision (Benefit) for Income Taxes

The 2012 provision for income taxes of $3,274,000 was based on a pre-tax income of $10,644,996, as compared to a provision for income taxes of $3,192,000 in 2011, based on a pre-tax income of $11,685,912. The effective tax rate for 2012 was 31%, compared to an effective tax rate for 2011 of 27%. The 2012 effective tax rate increase of 4% was due to increased state income taxes of $553,926, partially offset by an excess percentage depletion benefit increase of $112,524. The 2012 state income tax increase was a result of significantly higher lease bonus income in Oklahoma, combined with lower intangible drilling cost deductions from Oklahoma taxable income. The Company's utilization of excess percentage depletion (which is a permanent tax benefit) decreases the provision for income taxes. The benefit of excess percentage depletion is not directly related to the amount of recorded income or loss. Accordingly, in cases where the recorded income or loss is relatively small, the proportional effect of the excess percentage depletion on the effective tax rate may become significant.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2013, the Company had positive working capital of $7,504,588, as compared to positive working capital of $3,995,103 at September 30, 2012.

Liquidity

Cash and cash equivalents were $2,867,171 as of September 30, 2013, compared to $1,984,099 at September 30, 2012, an increase of $883,072. Cash flows for the 12 months ended September 30 are summarized as follows:

Net cash provided (used) by:

	2013	2012	Change
Operating activities	$ 37,402,109	$ 25,371,196	$ 12,030,913
Investing activities	(26,364,675)	(38,288,960)	11,924,285
Financing activities	(10,154,362)	11,394,864	(21,549,226)
Increase (decrease) in cash and cash equivalents	$ 883,072	$ (1,522,900)	$ 2,405,972

Operating activities:

Net cash provided by operating activities increased $12,030,913 during 2013, as compared to 2012, the result of the following:

- Receipts of oil, NGL and natural gas sales (net of production taxes and gathering, transportation and marketing costs) increased $11,844,281.
- Increased receipts from partnership distributions of $316,418 combined with lower income tax payments of $505,466.
- Decreased net realized gains on derivative contracts of $448,478.
- Increased cash expenditures for field related LOE of $435,800.

Investing activities:

Net cash used in investing activities decreased $11,924,285 during 2013, as compared to 2012, due to:

- A decrease in cash used to acquire properties of $19,360,371 ($18.8 million was used in the first quarter of 2012 to acquire producing properties, leasehold and mineral acreage in Arkansas).
- Lower lease bonus payments received during 2013 of $1,023,368, compared to $7,265,808 during 2012, which decreased cash provided by investing activities by $6,242,440.
- Higher drilling and completion activity during 2013 increased capital expenditures by $1,618,479.

Financing activities:

2013 net cash used in financing activities was $10,154,362, as compared to net cash provided by financing activities in 2012 of $11,394,864, resulting in a net increase of $21,549,226 of cash used in financing activities. This change is the result of the following:

- The Company financed the first quarter 2012 acquisition of producing properties and leasehold in Arkansas by utilizing its bank credit facility and cash. For fiscal 2012, cash provided by financing activities through net borrowings was $14,874,985. For fiscal 2013, cash used in financing activities to reduce outstanding borrowings was $6,612,729. The combined effect is a decrease in cash provided by financing activities of $21,487,714.

Capital Resources

Capital expenditures to drill and complete wells increased $1,618,479 (6%) in 2013, as compared to 2012. Oil and NGL rich plays in western Oklahoma and the Texas Panhandle account for the majority of 2013 drilling activity. Other active areas include the Arkansas Fayetteville Shale (dry natural gas), southern Oklahoma Woodford Shale (oil and NGL rich), Permian Basin of West Texas (oil and NGL rich) and Bakken Shale in North Dakota (oil).

Drilling continues to be active in the following oil and NGL rich plays where the Company owns mineral and leasehold acreage:

- Horizontal Granite Wash and Hogshooter in western Oklahoma and the Texas Panhandle
- Horizontal Cleveland in western Oklahoma and the Texas Panhandle
- Horizontal Marmaton in western Oklahoma
- Horizontal Tonkawa in western Oklahoma
- Horizontal Anadarko Basin Woodford Shale in western Oklahoma
- Horizontal Ardmore Basin Woodford Shale in southern Oklahoma

In addition to the $26,765,785 of capital expenditures for drilling and completion projects in 2013, mineral acreage in the Arkansas Fayetteville Shale and the southeast Oklahoma Woodford Shale was acquired for $783,750. Management continues to evaluate opportunities to acquire additional production or acreage.

Management currently expects to incur approximately $33 million of capital expenditures for drilling and completion projects during 2014. The shift of capital outlays more toward oil and NGL rich plays and less toward plays for dry natural gas is expected to result in increased oil and NGL production volumes in 2014, with expectations that natural gas production will level off. As experienced previously, the timing of new wells coming on line may cause intermittent increases or decreases in oil, NGL and natural gas production from quarter to quarter.

Since the Company is not the operator of any of its oil and natural gas properties, it is extremely difficult for us to precisely predict levels of future participation in the drilling and completion of new wells and associated capital expenditures.

Production of oil, NGL and natural gas increased 22% on an Mcfe basis during 2013, as compared to 2012. The production increase was the result of new production coming on line which exceeded the natural production decline of existing wells. We expect 2014 production volumes to exceed that of 2013 as drilling will result in new production coming on line throughout 2014.

Panhandle's oil sales price has averaged 93% of NYMEX oil price during 2013. Based on this correlation, and NYMEX oil futures prices, we expect the Company's average oil sales price for 2014 to approximate $88.00 per barrel. For 2013, NGL sales prices averaged 30% of NYMEX oil price; this would correlate to an average NGL sales price for 2014 of approximately $28.00 per barrel, which is also in line with management's expectations.

For 2013, Panhandle's natural gas sales price averaged 94% of NYMEX natural gas price. Based on NYMEX natural gas futures prices, management expects the Company's average natural gas sales price for 2014 to approximate $3.40 per Mcf.

With continued oil and natural gas price volatility, management continues to evaluate opportunities for product price protection through additional hedging of the Company's future oil and natural gas production. See Note 1 to the financial statements included in Item 8 - "Financial Statements and Supplementary Data" for a complete list of the Company's outstanding derivative contracts.

The use of the Company's cash provided by operating activities and resultant change to cash is summarized in the table below:

	Twelve months ended 9/30/2013
Cash provided by operating activities	$ 37,402,109
Cash used for:	
Capital expenditures - drilling and completion of wells	26,765,785
Quarterly dividends of $.07 per share	2,326,995
Treasury stock purchases	1,214,638
Net principal payments on credit facility	6,612,729
Other investing activities	(401,110)
Net cash used	36,519,037
Net increase (decrease) in cash	$ 883,072

Outstanding borrowings on the credit facility at September 30, 2013, were $8,262,256.

Looking forward, the Company expects to fund overhead costs, capital additions related to the drilling and completion of wells, treasury stock purchases and dividend payments primarily from cash provided by operating activities and cash on hand. As management evaluates opportunities to acquire additional assets, additional borrowings utilizing our bank credit facility could be necessary. Also, during times of oil, NGL and natural gas price decreases, or increased capital expenditures, it may be necessary to utilize the credit facility further in order to fund these expenditures. The Company has availability ($26,737,744 at September 30, 2013) under its revolving credit facility and is in compliance with its debt covenants (current ratio, debt to EBITDA and dividends as a percent of operating cash flow). While the Company believes the availability could be increased (if needed) by placing more of the Company's properties as security under the revolving credit facility, increases are at the discretion of the bank.

Based on expected capital expenditure levels and anticipated cash provided by operating activities for 2014, the Company has sufficient liquidity to fund its ongoing operations and, combined with availability under its credit facility, to fund acquisitions.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has a credit facility with Bank of Oklahoma (BOK) consisting of a revolving loan with a limit in the amount of $80,000,000, which is subject to a semi-annual borrowing base determination. The current borrowing base is $35,000,000 and is secured by certain of the Company's properties with a carrying value of $40,042,933 at September 30, 2013. The revolving loan matures on November 30, 2017. Borrowings under the revolving loan are due at maturity. The revolving loan bears interest at the BOK prime rate plus a range of 0.375% to 1.125%, or 30 day LIBOR plus a range of 1.875% to 2.625% annually. The election of BOK prime or LIBOR is at the Company's discretion. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the loan value of the Company's oil and natural gas properties is advanced.

Determinations of the borrowing base are made semi-annually, whenever BOK believes there has been a material change in the value of the Company's oil and natural gas properties or upon reasonable request by the Company. The loan agreement contains customary covenants, which, among other things, require periodic financial and reserve reporting and limit the Company's incurrence of indebtedness, liens, dividends and acquisitions of treasury stock and require the Company to maintain certain financial ratios. At September 30, 2013, the Company was in compliance with these covenants.

The table below summarizes the Company's contractual obligations and commitments as of September 30, 2013:

	Payments due by period				
Contractual Obligations and Commitments	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$ 8,262,256	$ -	$ 8,262,256	$ -	$ -
Building lease	$ 323,141	$ 204,089	$ 119,052	$ -	$ -

At September 30, 2013, the Company's derivative contracts were in a net asset position of $425,198. The ultimate settlement amounts of the derivative contracts are unknown because they are subject to continuing market risk. Please read Item 7A - "Quantitative and Qualitative Disclosures about Market Risk" and Note 1 to the financial statements included in Item 8 - "Financial Statements and Supplementary Data" for additional information regarding the derivative contracts.

As of September 30, 2013, the Company's asset retirement obligations were $2,393,190. Asset retirement obligations represent the Company's share of the future expenditures to plug and abandon the wells in which the Company owns a working interest when the oil, NGL and natural gas reserves are depleted. These amounts were not included in the schedule above due to the uncertainty of timing of the obligations. Please read Note 1 to the financial statements included in Item 8 - "Financial Statements and Supplementary Data" for additional information regarding the Company's asset retirement obligations.

CRITICAL ACCOUNTING POLICIES

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by the Company generally do not change the Company's reported cash flows or liquidity. Existing rules must be interpreted and judgments made on how the specifics of a given rule apply to the Company.

The more significant reporting areas impacted by management's judgments and estimates are crude oil, NGL and natural gas reserve estimation; derivative contracts; impairment of assets; oil, NGL and natural gas sales revenue accruals; refundable production taxes and provision for income tax. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, consultants and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known. The oil, NGL and natural gas sales revenue accrual is particularly subject to estimate inaccuracies due to the Company's status as a non-operator on all of its properties. As such, production and price information obtained from well operators is substantially delayed. This causes the estimation of recent production and prices used in the oil, NGL and natural gas revenue accrual to be subject to future change.

Oil, NGL and Natural Gas Reserves

Management considers the estimation of the Company's crude oil, NGL and natural gas reserves to be the most significant of its judgments and estimates. These estimates affect the unaudited standardized measure disclosures included in Note 11 to the financial statements in Item 8 - "Financial Statements and Supplementary Data," as well as DD&A and impairment calculations. Changes in crude oil, NGL and natural gas reserve estimates affect the Company's calculation of DD&A, asset retirement obligations and assessment of the need for asset impairments. On an annual basis, with a semi-annual update, the Company's Independent Consulting Petroleum Engineer, with assistance from Company staff, prepares estimates of crude oil, NGL and natural gas reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. Between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing prices which are updated through the current period. In accordance with the SEC rules, the reserve estimates were based on average individual product prices during the 12-month period prior to September 30 determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. Based on the Company's 2013 DD&A, a 10% change in the DD&A rate per Mcfe would result in a corresponding $2,194,577 annual change in DD&A expense. Crude oil, NGL and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. However, projected future crude oil, NGL and natural gas pricing assumptions are used by management to prepare estimates of crude oil, NGL and natural gas reserves and future net cash flows used in asset impairment assessments and in formulating management's overall operating decisions.

Successful Efforts Method of Accounting

The Company has elected to utilize the successful efforts method of accounting for its oil and natural gas exploration and development activities. This means exploration expenses, including geological and geophysical costs, non-producing lease impairment, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized by property using the unit-of-production method (the ratio of oil, NGL and natural gas volumes produced to total proved or proved developed reserves is used to amortize the remaining asset basis on each producing property) as oil, NGL and natural gas is produced. The Company's exploratory wells are all on-shore and primarily located in the Mid-Continent area. Generally, expenditures on exploratory wells comprise less than 10% of the Company's total expenditures for oil and natural gas properties. This accounting method may yield significantly different operating results than the full cost method.

Derivative Contracts

The Company has entered into oil and natural gas costless collar contracts, oil and natural gas fixed swap contracts and natural gas basis protection swaps. These instruments are intended to reduce the Company's exposure to short-term fluctuations in the price of oil and natural gas. Collar contracts set a fixed floor price and a fixed ceiling price and provide payments to the Company if the index price falls below the floor or require payments by the Company if the index price rises above the ceiling. Fixed swap contracts set a fixed price and provide for payments to the Company if the index price is below the fixed price, or require payments by the Company if the index price is above the fixed price. Basis protection swaps are derivatives that guarantee a price differential to NYMEX for natural gas from a specified delivery point (CEGT and PEPL historically). The Company receives a payment from the counterparty if the price differential is greater than the agreed terms of the contract and pays the counterparty if the price differential is less than the agreed terms of the contract. These contracts cover only a portion of the Company's oil and natural gas production and provide only partial price protection against declines in oil and natural gas prices. These derivative instruments expose the Company to risk of financial loss and may limit the benefit of future increases in prices. All of the Company's derivative contracts are with Bank of Oklahoma and are secured.

The Company is required to recognize all derivative instruments as either assets or liabilities in the balance sheet at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. At September 30, 2013, the Company had no derivative contracts designated as cash flow hedges, and therefore, changes in the fair value of derivatives are reflected in earnings.

Impairment of Assets

All long-lived assets, principally oil and natural gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than its estimated future net cash flows. The evaluations involve significant judgment since the results are based on estimated future events, such as inflation rates; future sales prices for oil, NGL and natural gas; future production costs; estimates of future oil, NGL and natural gas reserves to be recovered and the timing thereof; economic and regulatory climates and other factors. The Company estimates future net cash flows on its oil and natural gas properties utilizing differentially adjusted forward pricing curves for oil, NGL and natural gas and a discount rate in line with the discount rate we believe is most commonly used by the market participants (10% for all periods presented). The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to oil, NGL and natural gas reserves. A significant reduction in oil, NGL and natural gas prices (which are reviewed quarterly) or a decline in reserve volumes (which are re-evaluated semi-annually) would likely lead to additional impairment that may be material to the Company. Any assets held for sale are reviewed for impairment when the Company approves the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded.

Non-producing oil and natural gas leases are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties' costs, which the Company believes will not be transferred to proved properties over the remaining lives of the leases. Impairment loss is charged to exploration costs when recognized. As of September 30, 2013, the remaining carrying cost of non-producing oil and natural gas leases was $285,752.

Oil, NGL and Natural Gas Sales Revenue Accrual

The Company does not operate its oil and natural gas properties and, therefore, receives actual oil, NGL and natural gas sales volumes and prices (in the normal course of business) over a month later than the information is available to the operators of the wells. This being the case, on wells with greater significance to the Company, the most current available production data is gathered from the appropriate operators, and oil, NGL and natural gas index prices local to each well are used to estimate the accrual of revenue on these wells. Timely obtaining production data on all other wells from the operators is not feasible; therefore, the Company utilizes past production receipts and estimated sales price information to estimate its accrual of revenue on all other wells each quarter. The oil, NGL and natural gas sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil, NGL and natural gas. These variables could lead to an over or under accrual of oil, NGL and natural gas sales at the end of any particular quarter. Based on past history, the Company's estimated accrual has been materially accurate.

Income Taxes

The estimation of the amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations, as well as the completion of complex calculations, including the determination of the Company's percentage depletion deduction, if any. To calculate the exact excess percentage depletion allowance, a well-by-well calculation is, and can only be, performed at the end of each fiscal year. During interim periods, an estimate is made taking into account historical data and current pricing. The Company has certain state net operating loss carry forwards (NOLs) that are recognized as tax assets when assessed as more likely than not to be utilized before their expiration dates. Criteria such as expiration dates, future excess state depletion and reversing taxable temporary differences are evaluated to determine whether the NOLs are more likely than not to be utilized before they expire. If any NOLs are determined to no longer be more likely than not to be utilized, then a valuation allowance is recognized to reduce the tax benefit of such NOLs. Although the Company's management believes its tax accruals are adequate, differences may occur in the future depending on the resolution of pending and new tax matters.

Refundable Production Taxes Accrual

The State of Oklahoma allows for refunds of production taxes on wells that are horizontally drilled. In order to qualify as a horizontally drilled well, the well must have been completed in a manner which encounters and subsequently produces from a geological formation at an angle in excess of seventy degrees from vertical and which laterally penetrates a minimum of one hundred and fifty feet into the pay zone of the formation. An operator has 18 months after a given tax year to file the appropriate forms with the Oklahoma Tax Commission requesting the refund of production taxes. The refund is limited to 48 months from first sales or well payout, whichever comes first. Horizontal drilling in Oklahoma over the past four years has resulted in the addition of numerous wells that qualify for the Oklahoma horizontal exemption, thus increasing the Company's oil, NGL and natural gas sales subject to the accrual.

The Company does not operate any of its oil and natural gas properties and thus must rely on oil, NGL and natural gas sales and drilling information from the operators. The Company utilizes payment remittances from operators to estimate its refundable production tax accrual at the end of each quarterly period. The refundable production tax accrual can be impacted by many variables, including subsequent revenue adjustments received from operators and an operator's failure to file timely with the Oklahoma Tax Commission requesting refunds. These variables could lead to an over or under accrual of production taxes at the end of any particular period. Based on historical experience, the estimated accrual has been materially accurate.

During the 2010 legislative session, the Oklahoma State Legislature passed House Bill 2432, which provided for the deferral of the payment of certain gross production tax rebates by the Oklahoma Tax Commission for the 12-month production periods ending June 30, 2010, (tax year 2010) and June 30, 2011, (tax year 2011) for horizontally drilled wells. These deferred payments are being paid out over a period of three years beginning July 1, 2012. As a concession to producers for accepting the three-year deferral period, the State of Oklahoma, beginning with July 1, 2012, production, reduced the production tax rate rather than pay rebates in future periods. As such, the latest production date in the refundable production tax accrual is June 30, 2011.

The above description of the Company's critical accounting policies is not intended to be an all-inclusive discussion of the uncertainties considered and estimates made by management in applying generally accepted accounting principles and policies. Results may vary significantly if different policies were used or required and if new or different information becomes known to management.

ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk

Oil, NGL and natural gas prices historically have been volatile, and this volatility is expected to continue. Uncertainty continues to exist as to the direction of oil, NGL and natural gas price trends, and there remains a wide divergence in the opinions held in the industry. Being primarily a natural gas producer, the Company is more significantly impacted by changes in natural gas prices than by changes in oil or NGL prices. Longer term natural gas prices will be determined by the supply of and demand for natural gas as well as the prices of competing fuels, such as crude oil and coal. The market price of oil, NGL and natural gas in 2014 will impact the amount of cash generated from operating activities, which will in turn impact the level of the Company's capital expenditures and production. Excluding the impact of the Company's 2014 natural gas derivative contracts (see below), based on the Company's estimated natural gas volumes for 2014, the price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $1,100,000 for operating revenue. Based on the Company's estimated oil volumes for 2014, the price sensitivity in 2014 for each $1.00 per barrel change in wellhead oil is approximately $300,000 for operating revenue.

Commodity Price Risk

The Company periodically utilizes derivative contracts to reduce its exposure to unfavorable changes in natural gas and oil prices. The Company does not enter into these derivatives for speculative or trading purposes. All of our outstanding derivative contracts are with Bank of Oklahoma and are secured. These arrangements cover only a portion of the Company's production and provide only partial price protection against declines in natural gas and oil prices. These derivative contracts may expose the Company to risk of financial loss and limit the benefit of future increases in prices. For the Company's natural gas fixed price swaps, a change of $.10 in the NYMEX Henry Hub forward strip prices would result in a change to pre-tax operating income of approximately $49,000. For the Company's oil fixed price swaps, a change of $1.00 in the NYMEX WTI forward strip prices would result in a change to pre-tax operating income of approximately $16,000. For the Company's natural gas collars, a change of $.10 in the basis differential from NYMEX Henry Hub forward strip pricing would result in a change to pre-tax operating income of approximately $107,000. For the Company's oil collars, a change of $1.00 in the basis differential from NYMEX WTI forward strip prices would result in a change to pre-tax operating income of approximately $44,000.

Financial Market Risk

Operating income could also be impacted, to a lesser extent, by changes in the market interest rates related to the Company's credit facility. The revolving loan bears interest at the BOK prime rate plus from 0.375% to 1.125%, or 30 day LIBOR plus from 1.875% to 2.625%. At September 30, 2013, the Company had $8,262,256 outstanding under this facility. At this point, the Company does not believe that its liquidity has been materially affected by the debt market uncertainties noted in the last few years and the Company does not believe that its liquidity will be impacted in the near future.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Annual Report on Internal Control Over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934 (the "Exchange Act") as a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2013. In making this assessment, the Company's management used the criteria set forth in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, management has concluded that, as of September 30, 2013, the Company's internal control over financial reporting was effective based on those criteria.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. This report appears on the following page.

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Stockholders of
Panhandle Oil and Gas Inc.

We have audited Panhandle Oil and Gas Inc.'s internal control over financial reporting as of September 30, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Panhandle Oil and Gas Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Panhandle Oil and Gas Inc. maintained, in all material respects, effective internal control over financial reporting as of September 30, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the balance sheets of Panhandle Oil and Gas Inc. as of September 30, 2013 and 2012, and the related statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2013 and our report dated December 11, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 11, 2013

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Panhandle Oil and Gas Inc.

We have audited the accompanying balance sheets of Panhandle Oil and Gas Inc. (the Company) as of September 30, 2013 and 2012, and the related statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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 financial statements referred to above present fairly, in all material respects, the financial position of Panhandle Oil and Gas Inc. at September 30, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Panhandle Oil and Gas Inc.'s internal control over financial reporting as of September 30, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated December 11, 2013, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 11, 2013

Panhandle Oil and Gas Inc.
Balance Sheets

	September 30, 2013	September 30, 2012
Assets		
Current Assets:		
Cash and cash equivalents	$ 2,867,171	$ 1,984,099
Oil, NGL and natural gas sales receivables	13,720,761	8,349,865
Refundable income taxes	-	325,715
Refundable production taxes	662,051	585,454
Deferred income taxes	-	121,900
Derivative contracts	425,198	-
Other	129,998	255,812
Total current assets	17,805,179	11,622,845
Properties and equipment at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	304,889,145	275,997,569
Non-producing oil and natural gas properties	8,932,905	10,150,561
Furniture and fixtures	737,368	668,004
	314,559,418	286,816,134
Less accumulated depreciation, depletion and amortization	(186,641,291)	(165,199,079)
Net properties and equipment	127,918,127	121,617,055
Investments	1,574,642	1,034,870
Refundable production taxes	540,482	911,960
Total assets	$ 147,838,430	$ 135,186,730

(Continued on next page)

See accompanying notes.

Panhandle Oil and Gas Inc.
Balance Sheets

	September 30, 2013	September 30, 2012
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts payable	$ 8,409,634	$ 6,447,692
Derivative contracts	-	172,271
Deferred income taxes	127,100	-
Income taxes payable	751,992	-
Accrued liabilities and other	1,011,865	1,007,779
Total current liabilities	10,300,591	7,627,742
Long-term debt	8,262,256	14,874,985
Deferred income taxes	31,226,907	26,708,907
Asset retirement obligations	2,393,190	2,122,950
Stockholders' equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized, 8,431,502 issued at September 30, 2013 and 2012	140,524	140,524
Capital in excess of par value	2,587,838	2,020,229
Deferred directors' compensation	2,756,526	2,676,160
Retained earnings	96,454,449	84,821,395
	101,939,337	89,658,308
Treasury stock, at cost; 200,248 shares at September 30, 2013, and 181,310 shares at September 30, 2012	(6,283,851)	(5,806,162)
Total stockholders' equity	95,655,486	83,852,146
Total liabilities and stockholders' equity	$ 147,838,430	$ 135,186,730

See accompanying notes.

Panhandle Oil and Gas Inc.
Statements of Operations

	Year ended September 30,		
	2013	2012	2011
Revenues:			
Oil, NGL and natural gas sales	$ 60,605,878	$ 40,818,434	$ 43,469,130
Lease bonuses and rentals	938,846	7,152,991	352,757
Gains (losses) on derivative contracts	611,024	73,822	734,299
Income from partnerships	733,372	487,070	420,465
	62,889,120	48,532,317	44,976,651
Costs and expenses:			
Lease operating expenses	11,861,403	9,141,970	8,441,754
Production taxes	1,834,840	1,449,537	1,456,755
Exploration costs	9,795	979,718	1,025,542
Depreciation, depletion and amortization	21,945,768	19,061,239	14,712,188
Provision for impairment	530,670	826,508	1,728,162
Loss (gain) on asset sales, interest and other	(785,401)	39,493	(68,325)
General and administrative	6,801,996	6,388,856	5,994,663
	42,199,071	37,887,321	33,290,739
Income (loss) before provision (benefit) for income taxes	20,690,049	10,644,996	11,685,912
Provision (benefit) for income taxes	6,730,000	3,274,000	3,192,000
Net income (loss)	$ 13,960,049	$ 7,370,996	$ 8,493,912
Basic and diluted earnings per common share:			
Net income (loss)	$ 1.67	$ 0.88	$ 1.01

See accompanying notes.

Panhandle Oil and Gas Inc.
Statements of Stockholders' Equity

	Class A voting Common Stock Shares	Class A voting Common Stock Amount	Capital in Excess of Par Value	Deferred Directors' Compensation	Retained Earnings	Treasury Shares	Treasury Stock	Total
Balances at September 30, 2010	8,431,502	$ 140,524	$ 1,816,365	$ 2,222,127	$ 73,599,733	(120,560)	$ (4,196,753)	$ 73,581,996
Purchase of treasury stock	-	-	-	-	-	(65,481)	(1,851,290)	(1,851,290)
Issuance of treasury shares to ESOP	-	-	(44,340)	-	-	10,710	348,183	303,843
Restricted stock awards	-	-	152,482	-	-	-	-	152,482
Common shares to be issued to directors for services	-	-	-	443,456	-	-	-	443,456
Dividends declared ($.28 per share)	-	-	-	-	(2,322,082)	-	-	(2,322,082)
Net income	-	-	-	-	8,493,912	-	-	8,493,912
Balances at September 30, 2011	8,431,502	$ 140,524	$ 1,924,507	$ 2,665,583	$ 79,771,563	(175,331)	$ (5,699,860)	$ 78,802,317
Purchase of treasury stock	-	-	-	-	-	(38,771)	(1,158,957)	(1,158,957)
Issuance of treasury shares to ESOP	-	-	(14,391)	-	-	10,660	341,333	326,942
Restricted stock awards	-	-	330,923	-	-	-	-	330,923
Distribution of deferred directors' compensation	-	-	(220,810)	(406,770)	-	22,132	711,322	83,742
Common shares to be issued to directors for services	-	-	-	417,347	-	-	-	417,347
Dividends declared ($.28 per share)	-	-	-	-	(2,321,164)	-	-	(2,321,164)
Net income	-	-	-	-	7,370,996	-	-	7,370,996
Balances at September 30, 2012	8,431,502	$ 140,524	$ 2,020,229	$ 2,676,160	$ 84,821,395	(181,310)	$ (5,806,162)	$ 83,852,146
Purchase of treasury stock	-	-	-	-	-	(42,206)	(1,214,638)	(1,214,638)
Issuance of treasury shares to ESOP	-	-	(33,812)	-	-	10,907	342,262	308,450
Restricted stock awards	-	-	683,968	-	-	-	-	683,968
Distribution of deferred directors' compensation	-	-	(82,547)	(297,154)	-	12,361	394,687	14,986
Common shares to be issued to directors for services	-	-	-	377,520	-	-	-	377,520
Dividends declared ($.28 per share)	-	-	-	-	(2,326,995)	-	-	(2,326,995)
Net income	-	-	-	-	13,960,049	-	-	13,960,049
Balances at September 30, 2013	8,431,502	$ 140,524	$ 2,587,838	$ 2,756,526	$ 96,454,449	(200,248)	$ (6,283,851)	$ 95,655,486

See accompanying notes.

Panhandle Oil and Gas Inc.
Statements of Cash Flows

	Year ended September 30,		
	2013	2012	2011
Operating Activities			
Net income (loss)	$ 13,960,049	$ 7,370,996	$ 8,493,912
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	21,945,768	19,061,239	14,712,188
Impairment	530,670	826,508	1,728,162
Provision for deferred income taxes	4,767,000	1,802,000	1,878,000
Exploration costs	9,795	979,718	1,025,542
Gain from leasing fee mineral acreage	(936,701)	(7,146,299)	(352,642)
Net (gain) loss on sales of assets	(208,750)	(122,504)	2,112
Income from partnerships	(733,372)	(487,070)	(420,465)
Distributions received from partnerships	917,718	601,300	553,382
Common stock contributed to ESOP	308,450	326,942	303,843
Common stock (unissued) to Directors' Deferred Compensation Plan	377,520	417,347	443,456
Restricted stock awards	683,968	330,923	152,482
Cash provided (used) by changes in assets and liabilities:			
Oil, NGL and natural gas sales receivables	(5,370,896)	461,539	251,598
Fair value of derivative contracts	(597,469)	388,211	1,404,386
Refundable income taxes	325,715	28,531	(354,246)
Refundable production taxes	294,881	85,926	(124,621)
Other current assets	73,508	(108,098)	317,370
Accounts payable	298,191	585,912	72,119
Other non-current assets	-	308	-
Income taxes payable	751,992	-	(922,136)
Accrued liabilities	4,072	(32,233)	119,487
Total adjustments	23,442,060	18,000,200	20,790,017
Net cash provided by operating activities	37,402,109	25,371,196	29,283,929

(Continued on next page)

Panhandle Oil and Gas Inc.
Statements of Cash Flows (continued)

	Year ended September 30,		
	2013	2012	2011
Investing Activities			
Capital expenditures, including dry hole costs	$ (26,765,785)	$ (25,147,306)	$ (22,739,908)
Acquisition of working interest properties	-	(17,399,052)	(185,125)
Acquisition of minerals and overrides	(783,750)	(2,745,069)	(4,620,315)
Proceeds from leasing fee mineral acreage	1,023,368	7,265,808	389,807
Investments in partnerships	(724,118)	(481,904)	(46,213)
Proceeds from sales of assets	870,610	134,821	938
Excess tax benefit on stock-based compensation	15,000	83,742	-
Net cash used in investing activities	(26,364,675)	(38,288,960)	(27,200,816)
Financing Activities			
Borrowings under debt agreement	11,569,652	43,475,443	-
Payments of loan principal	(18,182,381)	(28,600,458)	-
Purchases of treasury stock	(1,214,638)	(1,158,957)	(1,851,290)
Payments of dividends	(2,326,995)	(2,321,164)	(2,322,082)
Net cash provided by (used in) financing activities	(10,154,362)	11,394,864	(4,173,372)
Increase (decrease) in cash and cash equivalents	883,072	(1,522,900)	(2,090,259)
Cash and cash equivalents at beginning of year	1,984,099	3,506,999	5,597,258
Cash and cash equivalents at end of year	$ 2,867,171	$ 1,984,099	$ 3,506,999
Supplemental Disclosures of Cash Flow Information			
Interest paid (net of capitalized interest)	$ 157,558	$ 127,970	$ -
Income taxes paid, net of refunds received	$ 870,295	$ 1,356,706	$ 2,584,172
Supplemental schedule of noncash investing and financing activities:			
Additions and revisions, net, to asset retirement obligations	$ 161,065	$ 279,075	$ 113,506
Gross additions to properties and equipment	$ 29,261,285	$ 46,201,308	$ 27,310,016
Net (increase) decrease in accounts payable for properties and equipment additions	(1,711,750)	(909,881)	235,332
Capital expenditures, including dry hole costs	$ 27,549,535	$ 45,291,427	$ 27,545,348

See accompanying notes.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Since its formation, the Company has been involved in the acquisition and management of fee mineral acreage and the exploration for, and development of, oil and natural gas properties, principally involving drilling wells located on the Company's mineral acreage. Panhandle's mineral properties and other oil and natural gas interests are all located in the United States, primarily in Arkansas, New Mexico, North Dakota, Oklahoma and Texas. The Company is not the operator of any wells. The Company's oil, NGL and natural gas production is from interests in 6,105 wells located principally in Oklahoma and Arkansas. Approximately 60% of oil, NGL and natural gas revenues were derived from the sale of natural gas in 2013. Approximately 84% of the Company's total sales volumes in 2013 were derived from natural gas. Substantially all the Company's oil, NGL and natural gas production is sold through the operators of the wells. The Company from time to time disposes of certain non-material, non-core or small-interest oil and natural gas properties in the normal course of business.

Use of Estimates

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts and disclosures reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Of these estimates and assumptions, management considers the estimation of crude oil, NGL and natural gas reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as DD&A and impairment calculations. On an annual basis, with a semi-annual update, the Company's Independent Consulting Petroleum Engineer, with assistance from the Company, prepares estimates of crude oil, NGL and natural gas reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. For DD&A purposes, and as required by the guidelines and definitions established by the SEC, the reserve estimates were based on average individual product prices during the 12-month period prior to September 30 determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. For impairment purposes, projected future crude oil, NGL and natural gas prices as estimated by management are used. Crude oil, NGL and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Projected future crude oil, NGL and natural gas pricing assumptions are used by management to prepare estimates of crude oil, NGL and natural gas reserves used in formulating management's overall operating decisions.

The Company does not operate its oil and natural gas properties and, therefore, receives actual oil, NGL and natural gas sales volumes and prices (in the normal course of business) over a month later than the information is available to the operators of the wells. This being the case, on wells with greater significance to the Company, the most current available production data is gathered from the appropriate operators, and oil, NGL and natural gas index prices local to each well are used to estimate the accrual of revenue on these wells. Timely obtaining production data on all other wells from the operators is not

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

feasible; therefore, the Company utilizes past production receipts and estimated sales price information to estimate its accrual of revenue on all other wells each quarter. The oil, NGL and natural gas sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil, NGL and natural gas. These variables could lead to an over or under accrual of oil, NGL and natural gas sales at the end of any particular quarter. Based on past history, the Company's estimated accrual has been materially accurate.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in short-term investments with original maturities of three months or less.

Oil, NGL and Natural Gas Sales and Natural Gas Imbalances

The Company sells oil, NGL and natural gas to various customers, recognizing revenues as oil, NGL and natural gas is produced and sold. Charges for compression, marketing, gathering and transportation of natural gas are included in lease operating expenses.

The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has underproduced or overproduced its ownership percentage in a property. Under this method, a receivable or liability is recorded to the extent that an underproduced or overproduced position in a well cannot be recouped through the production of remaining reserves. At September 30, 2013 and 2012, the Company had no material natural gas imbalances.

Accounts Receivable and Concentration of Credit Risk

Substantially all of the Company's accounts receivable are due from purchasers of oil, NGL and natural gas or operators of the oil and natural gas properties. Oil, NGL and natural gas sales receivables are generally unsecured. This industry concentration has the potential to impact our overall exposure to credit risk, in that the purchasers of our oil, NGL and natural gas and the operators of the properties we have an interest in may be similarly affected by changes in economic, industry or other conditions. During 2013 and 2012, we did not recognize a reserve for bad debt expense.

Oil and Natural Gas Producing Activities

The Company follows the successful efforts method of accounting for oil and natural gas producing activities. Intangible drilling and other costs of successful wells and development dry holes are capitalized and amortized. The costs of exploratory wells are initially capitalized, but charged against income if and when the well is determined to be nonproductive. Oil and natural gas mineral and leasehold costs are capitalized when incurred.

Non-producing oil and natural gas leases are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties' costs, which the Company believes will not be transferred to proved properties over the remaining lives of the leases. Impairment loss is charged to exploration costs when recognized. As of September 30, 2013, the remaining carrying cost of non-producing oil and natural gas leases was $285,752.

It is common business practice in the petroleum industry for drilling costs to be prepaid before spudding a well. The Company frequently fulfills these prepayment requirements with cash payments, but at times will utilize letters of credit to meet these obligations. As of September 30, 2013, the Company had no outstanding letters of credit.

Leasing of Mineral Rights

When the Company leases its mineral acreage to third-party exploration and production companies, it retains a royalty interest in any future revenues from the production and sale of oil, NGL or natural gas, and often receives an up-front, non-refundable, cash payment (lease bonus) in addition to the retained royalty interest. A royalty interest does not bear any portion of the cost of drilling, completing or operating a well; these costs are borne by the working interest owner. The Company sometimes leases only a portion of its mineral acres in a tract and retains the right to participate as a working interest owner with the remainder.

The Company recognizes revenue from mineral lease bonus payments when it has received an executed lease agreement with the exploration company transferring the rights to explore for and produce any oil or natural gas they may find within the term of the lease, the payment has been collected, and the Company has no obligation to refund the payment. The Company accounts for its lease bonuses in accordance with the guidance set forth in ASC 932, and it recognizes the lease bonus as a cost recovery with any excess above the mineral basis being treated as a gain. The excess of lease bonus above the mineral basis is shown in the lease bonuses and rentals line item on the Company's Statements of Operations.

Derivatives

The Company has entered into fixed swap contracts, basis protection swaps and costless collar contracts. These instruments are intended to reduce the Company's exposure to short-term fluctuations in the price of oil and natural gas. Collar contracts set a fixed floor price and a fixed ceiling price and provide payments to the Company if the index price falls below the floor or require payments by the Company if the index price rises above the ceiling. Fixed swap contracts set a fixed price and provide payments to the Company if the index price is below the fixed price, or require payments by the Company if the index price is above the fixed price. Basis protection swaps are derivatives that guarantee a price differential to NYMEX for natural gas from a specified delivery point (CEGT and PEPL historically). The Company receives a payment from the counterparty if the price differential is greater than the agreed terms of the contract and pays the counterparty if the price differential is less than the agreed terms of the contract. These contracts cover only a portion of the Company's oil and natural gas production and provide only partial price protection against declines in oil and natural gas prices. These

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

derivative instruments expose the Company to risk of financial loss and may limit the benefit of future increases in prices. All of the Company's derivative contracts are with Bank of Oklahoma and are secured. The derivative instruments have settled or will settle based on the prices below, which are adjusted for location differentials and tied to certain pipelines.

Derivative contracts in place as of September 30, 2012
(prices below reflect the Company's net price from the listed pipelines)

Contract period	Production volume covered per month	Indexed Pipeline	Fixed price
Natural gas basis protection swaps			
January - December 2012	50,000 Mmbtu	CEGT	NYMEX -$.29
January - December 2012	**40,000 Mmbtu**	**CEGT**	**NYMEX -$.30**
January - December 2012	50,000 Mmbtu	PEPL	NYMEX -$.29
January - December 2012	**50,000 Mmbtu**	**PEPL**	**NYMEX -$.30**
Natural gas costless collars			
March - October 2012	50,000 Mmbtu	NYMEX Henry Hub	$2.50 floor/$3.25 ceiling
April - October 2012	**120,000 Mmbtu**	**NYMEX Henry Hub**	**$2.50 floor/$3.10 ceiling**
April - October 2012	60,000 Mmbtu	NYMEX Henry Hub	$2.50 floor/$3.20 ceiling
April - October 2012	**50,000 Mmbtu**	**NYMEX Henry Hub**	**$2.50 floor/$3.20 ceiling**
April - October 2012	50,000 Mmbtu	NYMEX Henry Hub	$2.50 floor/$3.45 ceiling
April - October 2012	**50,000 Mmbtu**	**NYMEX Henry Hub**	**$2.50 floor/$3.30 ceiling**
August - October 2012	50,000 Mmbtu	NYMEX Henry Hub	$2.50 floor/$3.30 ceiling
November 2012 - January 2013	**150,000 Mmbtu**	**NYMEX Henry Hub**	**$3.00 floor/$3.70 ceiling**
November 2012 - January 2013	150,000 Mmbtu	NYMEX Henry Hub	$3.00 floor/$3.70 ceiling
November 2012 - January 2013	**50,000 Mmbtu**	**NYMEX Henry Hub**	**$3.00 floor/$3.65 ceiling**
Oil costless collars			
January - December 2012	2,000 Bbls	NYMEX WTI	$90 floor/$105 ceiling
February - December 2012	**3,000 Bbls**	**NYMEX WTI**	**$90 floor/$110 ceiling**
May - December 2012	2,000 Bbls	NYMEX WTI	$90 floor/$114 ceiling

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Derivative contracts in place as of September 30, 2013
(prices below reflect the Company's net price from the listed pipelines)

Contract period	Production volume covered per month	Indexed pipeline	Fixed price
Natural gas costless collars			
February - December 2013	80,000 Mmbtu	NYMEX Henry Hub	$3.75 floor/$4.25 ceiling
February - December 2013	**50,000 Mmbtu**	**NYMEX Henry Hub**	**$3.75 floor/$4.30 ceiling**
February - December 2013	100,000 Mmbtu	NYMEX Henry Hub	$3.75 floor/$4.05 ceiling
November 2013 - April 2014	**160,000 Mmbtu**	**NYMEX Henry Hub**	**$4.00 floor/$4.55 ceiling**
Natural gas fixed price swaps			
March - October 2013	100,000 Mmbtu	NYMEX Henry Hub	$3.505
March - October 2013	**70,000 Mmbtu**	**NYMEX Henry Hub**	**$3.400**
April - December 2013	40,000 Mmbtu	NYMEX Henry Hub	$3.655
May - November 2013	**100,000 Mmbtu**	**NYMEX Henry Hub**	**$4.320**
Oil costless collars			
March - December 2013	3,000 Bbls	NYMEX WTI	$90.00 floor/$102.00 ceiling
March - December 2013	**4,000 Bbls**	**NYMEX WTI**	**$90.00 floor/$101.50 ceiling**
May - December 2013	2,000 Bbls	NYMEX WTI	$90.00 floor/$97.50 ceiling
January - June 2014	**4,000 Bbls**	**NYMEX WTI**	**$90.00 floor/$101.50 ceiling**
Oil fixed price swaps			
September - December 2013	4,000 Bbls	NYMEX WTI	$105.250

The Company has elected not to complete the documentation requirements necessary to permit these derivative contracts to be accounted for as cash flow hedges. The Company's fair value of derivative contracts was a net asset of $425,198 as of September 30, 2013, and a net liability of $172,271 as of September 30, 2012. Realized and unrealized gains and (losses) are scheduled below:

Gains (losses) on natural gas derivative contracts	Fiscal year ended 9/30/2013	9/30/2012	9/30/2011
Realized	$ 13,555	$ 462,033	$ 2,138,685
Increase (decrease) in fair value	597,469	(388,211)	(1,404,386)
Total	$ 611,024	$ 73,822	$ 734,299

The fair value amounts recognized for the Company's derivative contracts executed with the same counterparty under a master netting arrangement may be offset. The Company has the choice to offset or not, but that choice must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

of default on or termination of any one contract. Offsetting the fair values recognized for the derivative contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Balance Sheets. The Company has chosen to present the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following table summarizes and reconciles the Company's derivative contracts' fair values at a gross level back to net fair value presentation on the Company's Condensed Balance Sheets at September 30, 2013, and September 30, 2012. The Company adopted the accounting guidance requiring additional disclosures for balance sheet offsetting of assets and liabilities effective January 1, 2013. The Company has offset all amounts subject to master netting agreements in the Company's Condensed Balance Sheets at September 30, 2013, and September 30, 2012.

	9/30/2013 Fair Value (a) Commodity Contracts		9/30/2012 Fair Value (a) Commodity Contracts	
	Current Assets	Current Liabilities	Current Assets	Current Liabilities
Gross amounts recognized	$ 665,099	$ 239,901	$ 51,530	$ 223,801
Offsetting adjustments	(239,901)	(239,901)	(51,530)	(51,530)
Net presentation on Condensed Balance Sheets	$ 425,198	$ -	$ -	$ 172,271

(a) See Fair Value Measurements section for further disclosures regarding fair value of financial instruments.

The fair value of derivative assets and derivative liabilities is adjusted for credit risk only if the impact is deemed material. The impact of credit risk was immaterial for all periods presented.

Fair Value Measurements

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs include the following: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active; (iii) inputs other than quoted prices that are observable for the asset or liability; or (iv) inputs that are derived principally from, or corroborated by, observable market data by correlation or other means. Level 3 inputs are unobservable inputs for the financial asset or liability.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis.

	Fair Value Measurement at September 30, 2013			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative Contracts - Swaps	$ -	$ 182,296	$ -	$ 182,296
Derivative Contracts - Collars	$ -	$ -	$ 242,902	$ 242,902

	Fair Value Measurement at September 30, 2012			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative Contracts - Swaps	$ -	$ (75,334)	$ -	$ (75,334)
Derivative Contracts - Collars	$ -	$ -	$ (96,937)	$ (96,937)

Level 2 - Market Approach - The fair values of the Company's natural gas swaps are based on a third-party pricing model which utilizes inputs that are either readily available in the public market, such as natural gas curves, or can be corroborated from active markets. These values are based upon future prices, time to maturity and other factors. These values are then compared to the values given by our counterparties for reasonableness.

Level 3 - The fair values of the Company's costless collar contracts are based on a pricing model which utilizes inputs that are unobservable or not readily available in the public market. These values are based upon future prices, volatility, time to maturity and other factors. These values are then compared to the values given by our counterparties for reasonableness.

The significant unobservable inputs for Level 3 derivative contracts include unpublished forward prices of oil and natural gas, market volatility and credit risk of counterparties. Changes in these inputs will impact the fair value measurement of our derivative contracts. An increase (decrease) in the forward prices and volatility of oil and natural gas prices will decrease (increase) the fair value of oil and natural gas derivatives, and adverse changes to our counterparties' creditworthiness will decrease the fair value of our derivatives.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The following table represents quantitative disclosures about unobservable inputs for Level 3 Fair Value Measurements.

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value September 30, 2013
Oil Collars	Oil price volatility curve	0% - 17.56%	10.27%	$ (233,041)
Natural Gas	Natural gas price volatility curve	0% - 19.67%	12.00%	$ 475,943

A reconciliation of the Company's derivative contracts classified as Level 3 measurements is presented below.

	Derivatives
Balance of Level 3 as of October 1, 2012	$ (96,937)
Total gains or (losses) - realized and unrealized:	
Included in earnings	
Realized	242,435
Unrealized	97,404
Included in other comprehensive income (loss)	-
Purchases, issuances and settlements	-
Transfers in and out of Level 3	-
Balance of Level 3 as of September 30, 2013	$ 242,902

The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

	Year Ended September 30,			
	2013		2012	
	Fair Value	Impairment	Fair Value	Impairment
Producing Properties	$ 356,855	$ 530,670	$ 1,301,951	$ 826,508 (a)

(a) At the end of each quarter, the Company assessed the carrying value of its producing properties for impairment. This assessment utilized estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of future oil, NGL and natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs and an applicable discount rate commensurate with risk of the underlying cash flow estimates. These assessments identified certain properties with carrying value in excess of their calculated fair values.

At September 30, 2013, and September 30, 2012, the fair value of financial instruments approximated their carrying amounts. Financial instruments include long-term debt, which the valuation is classified as Level 3 and is based on a valuation technique that requires inputs that are both unobservable and significant to the overall fair value measurement. The fair value measurement of our long-term debt is valued using a discounted cash flow model that calculates the present value of future

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

cash flows pursuant to the terms of the debt agreements and applies estimated current market interest rates. The estimated current market interest rates are based primarily on interest rates currently being offered on borrowings of similar amounts and terms. In addition, no valuation input adjustments were considered necessary relating to nonperformance risk for the debt agreements.

Depreciation, Depletion, Amortization and Impairment

Depreciation, depletion and amortization of the costs of producing oil and natural gas properties are generally computed using the unit-of-production method primarily on an individual property basis using proved or proved developed reserves, as applicable, as estimated by the Company's Independent Consulting Petroleum Engineer. The Company's capitalized costs of drilling and equipping all development wells and those exploratory wells that have found proved reserves are amortized on a unit-of-production basis over the remaining life of associated proved developed reserves. Lease costs are amortized on a unit-of-production basis over the remaining life of associated total proved reserves. Depreciation of furniture and fixtures is computed using the straight-line method over estimated productive lives of five to eight years.

Non-producing oil and natural gas properties include non-producing minerals, which had a net book value of $4,702,285 and $5,374,868 at September 30, 2013 and 2012, respectively, consisting of perpetual ownership of mineral interests in several states, with 91% of the acreage in Arkansas, New Mexico, North Dakota, Oklahoma and Texas. As mentioned, these mineral rights are perpetual and have been accumulated over the 87-year life of the Company. There are approximately 196,768 net acres of non-producing minerals in more than 6,818 tracts owned by the Company. An average tract contains approximately 29 acres, and the average cost per acre is $43. Since inception, the Company has continually generated an interest in several thousand oil and natural gas wells using its ownership of the fee mineral acres as an ownership basis. There continues to be significant drilling activity each year on these mineral interests. Non-producing minerals are being amortized straight-line over a 33-year period. These assets are considered a long-term investment by the Company, as they do not expire (as do oil and natural gas leases). Given the above, it was concluded that a long-term amortization was appropriate and that 33 years, based on past history and experience, was an appropriate period. Due to the fact that the minerals consist of a large number of properties, whose costs are not individually significant, and because virtually all are in the Company's core operating areas, the minerals are being amortized on an aggregate basis.

The Company recognizes impairment losses for long-lived assets when indicators of impairment are present and the undiscounted cash flows are not sufficient to recover the assets' carrying amount. The impairment loss is measured by comparing the fair value of the asset to its carrying amount. Fair values are based on discounted cash flow as estimated by the Company's Independent Consulting Petroleum Engineer. The Company's estimate of fair value of its oil and natural gas properties at September 30, 2013, is based on the best information available as of that date, including estimates of forward oil, NGL and natural gas prices and costs. The Company's oil and natural gas properties were reviewed for impairment on a field-by-field basis, resulting in the recognition of impairment provisions of $530,670, $826,508 and $1,728,162, respectively, for 2013, 2012 and 2011. A significant reduction in oil, NGL and natural gas prices or a decline in reserve volumes would likely lead to additional impairment in future periods that may be material to the Company.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Capitalized Interest

During 2013, 2012 and 2011, interest of $121,418, $129,172 and $0, respectively, was included in the Company's capital expenditures. Interest of $157,558, $127,970 and $0, respectively, was charged to expense during those periods. Interest is capitalized using a weighted average interest rate based on the Company's outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using unit-of-production method.

Investments

Insignificant investments in partnerships and limited liability companies (LLC) that maintain specific ownership accounts for each investor and where the Company holds an interest of 5% or greater, but does not have control of the partnership or LLC, are accounted for using the equity method of accounting.

Asset Retirement Obligations

The Company owns interests in oil and natural gas properties, which may require expenditures to plug and abandon the wells when the oil, NGL and natural gas reserves in the wells are depleted. The fair value of legal obligations to retire and remove long-lived assets is recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, this cost is capitalized by increasing the carrying amount of the related properties and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties and equipment is depreciated over the useful life of the remaining asset. The Company does not have any assets restricted for the purpose of settling the asset retirement obligations.

The following table shows the activity for the years ended September 30, 2013 and 2012, relating to the Company's asset retirement obligations:

	2013	2012
Asset Retirement Obligations as of beginning of the year	$ 2,122,950	$ 1,843,875
Accretion of Discount	122,391	121,112
New Wells Placed on Production	167,609	184,027
Wells Sold or Plugged	(19,760)	(26,064)
Asset Retirement Obligations as of end of the year	$ 2,393,190	$ 2,122,950

Environmental Costs

As the Company is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local provisions regarding environmental and ecological matters. Compliance with these laws may necessitate significant capital outlays; however, to date the Company's cost of compliance has been insignificant. The Company does not believe the existence of current environmental laws or interpretations thereof will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future effects on the Company of new laws or interpretations thereof. Since the Company does not operate any wells where it owns an interest, actual

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

compliance with environmental laws is controlled by others, with Panhandle being responsible for its proportionate share of the costs involved. Panhandle carries liability insurance and pollution control coverage. However, all risks are not insured due to the availability and cost of insurance.

Environmental liabilities, which historically have not been material, are recognized when it is probable that a loss has been incurred and the amount of that loss is reasonably estimable. Environmental liabilities, when accrued, are based upon estimates of expected future costs. At September 30, 2013 and 2012, there were no such costs accrued.

Earnings (Loss) Per Share of Common Stock

Earnings (loss) per share is calculated using net income (loss) divided by the weighted average number of common shares outstanding, plus unissued, vested directors' deferred compensation shares during the period.

Share-based Compensation

The Company recognizes current compensation costs for its Deferred Compensation Plan for Non-Employee Directors (the "Plan"). Compensation cost is recognized for the requisite directors' fees as earned and unissued stock is added to each director's account based on the fair market value of the stock at the date earned. The Plan's structure is that upon retirement, termination or death of the director or upon a change in control of the Company, the shares accrued under the Plan will be issued to the director.

In accordance with guidance on accounting for employee stock ownership plans, the Company records as expense the fair market value of the stock at the time of contribution into its ESOP.

Restricted stock awards to certain officers provide for cliff vesting at the end of three or five years from the date of the awards. The fair value of the awards is ratably expensed over the vesting period in accordance with accounting guidance.

Income Taxes

The estimation of amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations, as well as the completion of complex calculations, including the determination of the Company's percentage depletion deduction. Although the Company's management believes its tax accruals are adequate, differences may occur in the future depending on the resolution of pending and new tax regulations. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of the Company's assets and liabilities.

The threshold for recognizing the financial statement effect of a tax position is when it is more likely than not, based on the technical merits, that the position will be sustained by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not to be realized upon ultimate settlement with a taxing authority. The Company files income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Subject to statutory

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

exceptions that allow for a possible extension of the assessment period, the Company is no longer subject to U.S. federal, state, and local income tax examinations for fiscal years prior to 2010.

The Company includes interest assessed by the taxing authorities in interest expense and penalties related to income taxes in general and administrative expense on its Statements of Operations. For fiscal September 30, 2013, 2012 and 2011, the Company recorded interest and penalties of $927, $0 and $21,000, respectively. The Company does not believe it has any significant uncertain tax positions.

New Accounting Standards

In December 2011, the Financial Accounting Standards Board issued "Balance Sheet: Disclosures about Offsetting Assets and Liabilities." The new standard requires entities to disclose information about financial instruments and derivative instruments that are either offset on the balance sheet or are subject to a master netting arrangement, including providing both gross information and net information for recognized assets and liabilities, the net amounts presented on an entity's balance sheet and a description of the rights of offset associated with these assets and liabilities. The new standard is applicable for all entities that have financial instruments and derivative instruments shown using a net presentation on an entity's balance sheet or are subject to a master netting arrangement. The new standard is effective for interim and annual reporting periods for fiscal years beginning on or after January 1, 2013, and should be applied retrospectively for all periods presented. The Company adopted this new standard effective January 1, 2013.

Other accounting standards that have been issued or proposed by the FASB, or other standards-setting bodies, that do not require adoption until a future date are not expected to have a material impact on the financial statements upon adoption.

2. COMMITMENTS

The Company leases office space in Oklahoma City, Oklahoma, under the terms of an operating lease expiring in April 2015. Future minimum rental payments under the terms of the lease are $204,089 in 2014 and $119,052 in 2015. Total rent expense incurred by the Company was $200,782 in 2013, $204,011 in 2012 and $204,089 in 2011.

3. INCOME TAXES

The Company's provision (benefit) for income taxes is detailed as follows:

3. INCOME TAXES (CONTINUED)

	2013	2012	2011
Current:			
Federal	$ 1,813,000	$ 1,452,000	$ 1,266,000
State	150,000	20,000	48,000
	1,963,000	1,472,000	1,314,000
Deferred:			
Federal	4,003,000	1,126,000	1,982,000
State	764,000	676,000	(104,000)
	4,767,000	1,802,000	1,878,000
	$ 6,730,000	$ 3,274,000	$ 3,192,000

The difference between the provision (benefit) for income taxes and the amount which would result from the application of the federal statutory rate to income before provision (benefit) for income taxes is analyzed below for the years ended September 30:

	2013	2012	2011
Provision (benefit) for income taxes at statutory rate	$ 7,241,517	$ 3,725,749	$ 4,090,069
Percentage depletion	(1,059,303)	(846,040)	(733,516)
State income taxes, net of federal provision (benefit)	572,650	464,677	(92,989)
State net operating loss valuation allowance (release)	-	(31,000)	31,000
Other	(24,864)	(39,386)	(102,564)
	$ 6,730,000	$ 3,274,000	$ 3,192,000

Deferred tax assets and liabilities, resulting from differences between the financial statement carrying amounts and the tax basis of assets and liabilities, consist of the following at September 30:

3. INCOME TAXES (CONTINUED)

	2013	2012
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$ 33,557,515	$ 30,320,765
Derivative contracts	165,402	-
	33,722,917	30,320,765
Deferred tax assets:		
State net operating loss carry forwards, net of valuation allowance of $0 in 2013 and 2012	782,785	1,008,271
AMT credit carry forwards	-	1,189,053
Deferred directors' compensation	1,021,717	990,455
Restricted stock expense	426,788	-
Statutory depletion carry forwards	-	415,958
Other	137,620	130,021
	2,368,910	3,733,758
Net deferred tax liabilities	$ 31,354,007	$ 26,587,007

At September 30, 2013, the Company had an income tax benefit of $782,785 related to Oklahoma state income tax net operating loss (OK NOL) carry forwards expiring from 2028 to 2031. There is no valuation allowance for the OK NOL's as management believes they will be utilized before they expire.

4. LONG-TERM DEBT

The Company has a credit facility with Bank of Oklahoma (BOK) consisting of a revolving loan in the amount of $80,000,000, which is subject to a semi-annual borrowing base determination, wherein BOK applies their own current pricing forecast and an 8% discount rate to the Company's proved reserves as calculated by the Company's Independent Consulting Petroleum Engineering Firm. When applying the discount rate, BOK also applies an advance rate percentage to all proved non-producing and proved undeveloped reserves. The facility has a borrowing base of $35,000,000 and is secured by certain of the Company's properties with a carrying value of $40,042,933 at September 30, 2013. The facility matures on November 30, 2017. The interest rate is based on BOK prime plus from 0.375% to 1.125%, or 30 day LIBOR plus from 1.875% to 2.625%. The election of BOK prime or LIBOR is at the Company's discretion. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the loan value of the Company's oil and natural gas properties is advanced. The interest rate spread from BOK prime or LIBOR will be charged based on the percent of the value advanced of the calculated loan value of the Company's oil and natural gas properties. At September 30, 2013, the effective interest rate was 2.36%.

The Company's debt is recorded at the carrying amount on its balance sheet. The carrying amount of the Company's revolving credit facility approximates fair value because the interest rates are reflective of market rates.

4. LONG-TERM DEBT (CONTINUED)

Since the bank charges a customary non-use fee of 0.25% annually of the unused portion of the borrowing base, the Company has not requested the bank to increase its borrowing base beyond $35,000,000. Determinations of the borrowing base are made semi-annually or whenever the bank, in its sole discretion, believes that there has been a material change in the value of the oil and natural gas properties. While the Company believes the availability could be increased (if needed) by placing more of the Company's properties as security under the revolving credit facility, increases are at the discretion of the bank. The loan agreement contains customary covenants which, among other things, require periodic financial and reserve reporting and limit the Company's incurrence of indebtedness, liens, dividends and acquisitions of treasury stock, and require the Company to maintain certain financial ratios. At September 30, 2013, the Company was in compliance with the covenants of the BOK agreement.

5. SHAREHOLDERS' EQUITY

Upon approval by the shareholders of the Company's 2010 Restricted Stock Plan on March 11, 2010, the Board approved purchase of up to $1.5 million of the Company's Common Stock, from time to time, equal to the aggregate number of shares of Common Stock awarded pursuant to the Company's 2010 Restricted Stock Plan, contributed by the Company to its ESOP and credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors. The Board's approval included an initial authorization to purchase up to $1.5 million of Common Stock, with a provision for subsequent authorizations without specific action by the Board. As the amount of Common Stock purchased under any authorization reaches $1.5 million, another $1.5 million is automatically authorized for Common Stock purchases unless the Board determines otherwise. Pursuant to these resolutions adopted by the Board, the purchase of additional $1.5 million increments of the Company's Common Stock became authorized and approved effective March 29, 2011, March 14, 2012, and June 26, 2013. As of September 30, 2013, $4,516,267 had been spent under the current program to purchase 158,784 shares. The shares are held in treasury and are accounted for using the cost method. On September 30 each year, treasury shares contributed to the Company's ESOP on behalf of the ESOP participants were 10,907 in 2013, 10,660 in 2012 and 10,710 in 2011.

6. EARNINGS PER SHARE

The following table sets forth the computation of earnings per share.

	Year ended September 30,		
	2013	2012	2011
Numerator for basic and diluted earnings per share:			
Net income (loss)	$ 13,960,049	$ 7,370,996	$ 8,493,912
Denominator for basic and diluted earnings per share - weighted average shares (including for 2013, 2012 and 2011, unissued, vested directors' shares of 116,112, 114,596 and 122,728, respectively)	8,356,904	8,360,931	8,393,890

7. EMPLOYEE STOCK OWNERSHIP PLAN

The Company's ESOP was established in 1984 and is a tax qualified, defined contribution plan that serves as the Company's sole retirement plan for all its employees. Company contributions are made at the discretion of the Board and, to date, all contributions have been made in shares of Company Common Stock. The Company contributions are allocated to all ESOP participants in proportion to their compensation for the plan year, and 100% vesting occurs after three years of service. Any shares that do not vest are treated as forfeitures and are distributed among other vested employees. For contributions of Common Stock, the Company records as expense the fair market value of the stock at the time of contribution. The 259,060 shares of the Company's Common Stock held by the plan, as of September 30, 2013, are allocated to individual participant accounts, are included in the weighted average shares outstanding for purposes of earnings-per-share computations and receive dividends.

Contributions to the plan consisted of:

Year	Shares	Amount
2013	10,907	$ 308,450
2012	10,660	$ 326,942
2011	10,710	$ 303,843

8. DEFERRED COMPENSATION PLAN FOR DIRECTORS

The Panhandle Oil and Gas Inc. Deferred Compensation Plan for Non-Employee Directors (the "Plan") provides that each eligible director can individually elect to receive shares of Company Common Stock rather than cash for Board and committee chair retainers, Board meeting fees and Board committee meeting fees. These shares are unissued and vest as earned. The shares are credited to each director's deferred fee account at the closing market price of the stock on the date earned. As of September 30, 2013, there were 122,219 shares (121,348 shares at September 30, 2012) included in the Plan. The deferred balance outstanding at September 30, 2013, under the Plan was $2,756,526 ($2,676,160 at September 30, 2012). Expenses totaling $377,520, $417,347 and $443,456 were charged to the Company's results of operations for the years ended September 30, 2013, 2012 and 2011, respectively, and are included in general and administrative expense in the accompanying Statement of Operations.

9. RESTRICTED STOCK PLAN

On March 11, 2010, shareholders approved the Panhandle Oil and Gas Inc. 2010 Restricted Stock Plan (2010 Stock Plan), which made available 100,000 shares of Common Stock to provide a long-term component to the Company's total compensation package for its officers and to further align the interest of its officers with those of its shareholders. The 2010 Stock Plan is designed to provide as much flexibility as possible for future grants of restricted stock so the Company can respond as necessary to provide competitive compensation in order to retain, attract and motivate officers of the Company and to align their interests with those of the Company's shareholders.

In June 2010, the Company began awarding shares of the Company's Common Stock as restricted stock (non-performance based) to certain officers. The restricted stock vests at the end of the vesting period and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. The fair value of the shares was based on the closing price of the shares on their award date and will be

9. RESTRICTED STOCK PLAN (CONTINUED)

recognized as compensation expense ratably over the vesting period. Upon vesting, shares are expected to be issued out of shares held in treasury.

On December 21, 2010, the Company began awarding shares of the Company's Common Stock, subject to certain share price performance standards (performance based), as restricted stock to certain officers. Vesting of these shares is based on the performance of the market price of the Common Stock over the vesting period. The fair value of the performance shares was estimated on the grant date using a Monte Carlo valuation model that factors in information, including the expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance shares. Compensation expense for the performance shares is a fixed amount determined at the grant date and is recognized over the vesting period regardless of whether performance shares are awarded at the end of the vesting period. Upon vesting, shares are expected to be issued out of shares held in treasury.

Compensation expense for the restricted stock awards is recognized in G&A.

The following table summarizes the Company's pre-tax compensation expense for the years ended September 30, 2013, 2012 and 2011, related to the Company's performance based and non-performance based restricted stock.

	Year Ended September 30, 2013	2012	2011
Performance based, restricted stock	$ 345,405	$ 150,480	$ 42,909
Non-performance based, restricted stock	338,563	180,443	109,573
Total compensation expense	$ 683,968	$ 330,923	$ 152,482

A summary of the Company's unrecognized compensation cost for its unvested performance based and non-performance based restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

	Unrecognized Compensation Cost	Weighted Average Period (in years)
Performance based, restricted stock	$ 282,726	1.41
Non-performance based, restricted stock	227,628	1.48
Total	$ 510,354	

Upon vesting, shares are expected to be issued out of shares held in treasury.

A summary of the status of unvested shares of restricted stock awards and changes is presented below:

9. RESTRICTED STOCK PLAN (CONTINUED)

	Performance Based Unvested Restricted Shares	Weighted Average Grant-Date Fair Value	Non-Performance Based Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of September 30, 2010	-	$ -	8,500	$ 28.30
Granted	8,782	19.54	8,780	28.00
Vested	-	-	-	-
Forfeited	-	-	-	-
Unvested shares as of September 30, 2011	8,782	$ 19.54	17,280	$ 28.15
Granted	17,709	19.47	5,903	31.55
Vested	-	-	-	-
Forfeited	-	-	-	-
Unvested shares as of September 30, 2012	26,491	$ 19.49	23,183	$ 29.01
Granted	20,104	15.18	6,701	29.19
Vested	-	-	-	-
Forfeited	-	-	-	-
Unvested shares as of September 30, 2013	46,595	$ 17.63	29,884	$ 29.05

10. INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES

All oil and natural gas producing activities of the Company are conducted within the United States (principally in Oklahoma and Arkansas) and represent substantially all of the business activities of the Company.

The following table shows sales through various operators/purchasers during 2013, 2012 and 2011.

10. INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES (CONTINUED)

	2013	2012	2011
Southwestern Energy Company	20%	15%	9%
Chesapeake Operating, Inc.	10%	13%	15%
Devon Energy Corp.	7%	10%	9%
Apache Corporation	6%	4%	2%
Newfield Exploration	5%	7%	14%

11. SUPPLEMENTARY INFORMATION ON OIL, NGL AND NATURAL GAS RESERVES (UNAUDITED)

Aggregate Capitalized Costs

The aggregate amount of capitalized costs of oil and natural gas properties and related accumulated depreciation, depletion and amortization as of September 30 is as follows:

	2013	2012
Producing properties	$ 304,889,145	$ 275,997,569
Non-producing minerals	8,490,277	9,018,731
Non-producing leasehold	442,628	1,123,812
Exploratory wells in progress	-	8,018
	313,822,050	286,148,130
Accumulated depreciation, depletion and amortization	(186,042,746)	(164,652,199)
Net capitalized costs	$ 127,779,304	$ 121,495,931

Costs Incurred

For the years ended September 30, the Company incurred the following costs in oil and natural gas producing activities:

	2013	2012	2011
Property acquisition costs	$ 1,242,615	$ 20,404,465	$ 5,140,862
Exploration costs	-	1,210,417	4,837,451
Development costs	27,938,160	24,578,943	17,310,808
	$ 29,180,775	$ 46,193,825	$ 27,289,121

In 2012, $17.4 million of the property acquisition costs related to the acquisition of certain assets in the Arkansas Fayetteville Shale.

11. SUPPLEMENTARY INFORMATION ON OIL, NGL AND NATURAL GAS RESERVES (UNAUDITED) (CONTINUED)

Estimated Quantities of Proved Oil, NGL and Natural Gas Reserves

The following unaudited information regarding the Company's oil, NGL and natural gas reserves is presented pursuant to the disclosure requirements promulgated by the SEC and the FASB.

Proved oil and natural gas reserves are those quantities of oil and natural gas which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations - prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

The independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas, calculated the Company's oil, NGL and natural gas reserves as of September 30, 2013, 2012 and 2011 (see Exhibits 23 and 99).

The Company's net proved oil, NGL and natural gas reserves, all of which are located in the United States, as of September 30, 2013, 2012 and 2011, have been estimated by the Company's Independent Consulting Petroleum Engineering Firm. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering and evaluation principals and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of

11. SUPPLEMENTARY INFORMATION ON OIL, NGL AND NATURAL GAS RESERVES (UNAUDITED) (CONTINUED)

Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

All of the reserve estimates are reviewed and approved by our Vice President and COO, who reports directly to our President and CEO. Mr. Blanchard, our COO, holds a Bachelor of Science Degree in Petroleum Engineering from the University of Oklahoma. Before joining the Company, he was sole proprietor of a consulting petroleum engineering firm, spent 10 years as Vice President of the Mid-Continent business unit of Range Resources Corporation and spent several years as an engineer with Enron Oil and Gas. He is an active member of the Society of Petroleum Engineers (SPE) with over 27 years of oil and gas industry experience, including engineering assignments in several field locations.

Our COO and internal staff work closely with our Independent Consulting Petroleum Engineers to ensure the integrity, accuracy and timeliness of data furnished to them for their reserves estimation process. We provide historical information to our Independent Consulting Petroleum Engineers for all properties such as ownership interest, oil and gas production, well test data, commodity prices, operating costs and handling fees, and development costs. Throughout the year, our team meets regularly with representatives of our Independent Consulting Petroleum Engineers to review properties and discuss methods and assumptions.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data was available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

Accordingly, these estimates should be expected to change, and such changes could be material and occur in the near term as future information becomes available.

Net quantities of proved, developed and undeveloped oil, NGL and natural gas reserves are summarized as follows:

11. SUPPLEMENTARY INFORMATION ON OIL, NGL AND NATURAL GAS RESERVES (UNAUDITED) (CONTINUED)

	Proved Reserves		
	Oil (Barrels)	NGL (1) (Barrels)	Natural Gas (Mcf)
September 30, 2010	925,009	-	98,170,455
Revisions of previous estimates	(59,360)	791,648	769,676
Divestitures	-	-	3,189,520
Extensions, discoveries and other additions	82,230	-	8,005,990
Production	(104,141)	-	(8,297,657)
September 30, 2011	843,738	791,648	101,837,984
Revisions of previous estimates	8,627	(76,794)	(27,389,752)
Acquisitions	-	-	19,075,529
Extensions, discoveries and other additions	373,097	172,602	29,062,593
Production	(153,143)	(98,714)	(9,072,298)
September 30, 2012	1,072,319	788,742	113,514,056
Revisions of previous estimates	(90,968)	141,081	(2,697,853)
Acquisitions	-	-	1,660,649
Extensions, discoveries and other additions	896,036	798,200	30,698,644
Production	(234,084)	(111,897)	(10,886,329)
September 30, 2013	1,643,303	1,616,126	132,289,167

(1) 2011 was the first year the Company had sufficient volumes of NGL to warrant reserve volumes disclosure. These NGL are associated with the rapid increase in drilling activity in western and southern Oklahoma and the Texas Panhandle, which includes many plays (horizontal Granite Wash, Hogshooter Wash, Cleveland, Marmaton, Anadarko Basin Woodford Shale and Ardmore Basin Woodford Shale) producing significant volumes of NGL.

The prices used to calculate reserves and future cash flows from reserves for oil, NGL and natural gas, respectively, were as follows: September 30, 2013 - $89.06/Bbl, $27.28/Bbl, $3.33/Mcf ; September 30, 2012 -$89.41/Bbl, $35.70/Bbl, $2.51/Mcf ; September 30, 2011 - $90.28/Bbl, $38.91/Bbl, $3.81/Mcf.

The revisions of previous estimates from 2012 to 2013 were primarily the result of:

- Negative performance revisions of 5,844,070 Mcfe, of which 8,803,480 Mcfe were positive proved developed revisions principally due to better than projected well performance attributable to properties in Arkansas and Oklahoma. The remaining 14,647,551 Mcfe were negative proved undeveloped revisions principally attributable to the removal of dry gas

11. SUPPLEMENTARY INFORMATION ON OIL, NGL AND NATURAL GAS RESERVES (UNAUDITED) (CONTINUED)

reserves which are no longer projected to be developed within 5 years from the date they were added to the proved undeveloped reserves.

- Positive pricing revisions of 3,446,900 Mcfe due to proved developed wells (3,109,159 Mcfe) and proved undeveloped locations (337,741 Mcfe) reaching their economic limits later than previously projected, thus adding reserves, due to higher product prices.

Extensions, discoveries and other additions from 2012 to 2013 are principally attributable to:

- The Company's participation in ongoing development of conventional oil, NGL and natural gas plays utilizing horizontal drilling, including the Cleveland and Granite Wash plays in western Oklahoma and the Texas Panhandle, as well as the Marmaton and Hogshooter Wash plays in western Oklahoma.

- The Company's participation in ongoing development of unconventional natural gas plays utilizing horizontal drilling, including the Arkansas Fayetteville Shale and, to a much lesser extent, the Southeastern Oklahoma Woodford Shale.

- The Company's participation in ongoing development of unconventional oil, NGL and natural gas plays utilizing horizontal drilling in the Anadarko Basin Woodford Shale and Ardmore Basin Woodford Shale in western and southern Oklahoma.

- PUD additions principally in the Fayetteville Shale play in Arkansas, the Anadarko Basin Woodford Shale and Ardmore Basin Woodford Shale in western and southern Oklahoma and the Cleveland and Granite Wash plays in western Oklahoma and the Texas Panhandle, as well as the Marmaton and Hogshooter Wash plays in western Oklahoma. These additions are the result of reservoir delineation proved by continuing drilling and well performance data in each of the referenced plays.

	Proved Developed Reserves			Proved Undeveloped Reserves		
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)
September 30, 2011	759,989	386,774	60,193,878	83,749	404,874	41,644,106
September 30, 2012	849,548	494,160	65,733,119	222,771	294,582	47,780,937
September 30, 2013	1,037,721	764,321	82,298,833	605,582	851,805	49,990,334

The following details the changes in proved undeveloped reserves for 2013 (Mcfe):

11. SUPPLEMENTARY INFORMATION ON OIL, NGL AND NATURAL GAS RESERVES (UNAUDITED) (CONTINUED)

Beginning proved undeveloped reserves	50,885,055
Proved undeveloped reserves transferred to proved developed	(12,124,203)
Revisions	(14,309,809)
Extensions and discoveries	32,806,004
Purchases	1,477,609
Ending proved undeveloped reserves	58,734,656

The beginning PUD reserves were 50.9 Bcfe. A total of 12.1 Bcfe (24% of the beginning balance) were transferred to proved developed producing during 2013. The 14.3 Bcfe of negative revisions to PUD reserves consist of a positive pricing revision of 0.3 Bcfe offset by a 14.6 Bcfe (29% of the beginning balance) negative performance revision in 2013 as the result of removal of dry gas reserves which are no longer projected to be developed within 5 years from the date they were added. A total of 26.7 Bcfe (53% of the beginning balance) of PUD reserves were moved out of the category during 2013 as either the result of being transferred to proved developed or removed because they were no longer projected to be developed within 5 years from the date they were added to the proved undeveloped reserves. Only 21 PUD locations from 2009, representing 1% of total 2013 PUD reserves remain in the PUD category. We anticipate that all the Company's PUD locations will be drilled and converted to PDP within five years of the date they were added. However, PUD locations and associated reserves which are no longer projected to be drilled within 5 years from the date they were added to the proved undeveloped reserves will be removed as revisions at the time that determination is made and in the event that there are undrilled PUD locations at the end of the five-year period, it is our intent to remove the reserves associated with those locations from our proved reserves as revisions.

Standardized Measure of Discounted Future Net Cash Flows

Accounting Standards prescribe guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying the trailing unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs to the estimated quantities of oil, natural gas and NGL to be produced. Actual future prices and costs may be materially higher or lower than the unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for such year.

Estimated future income taxes are computed using current statutory income tax rates including consideration for the current tax basis of the properties and related carry forwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor. The assumptions used to compute the standardized measure are those prescribed by the FASB and, as such, do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

11. SUPPLEMENTARY INFORMATION ON OIL, NGL AND NATURAL GAS RESERVES (UNAUDITED) (CONTINUED)

	2013	2012	2011
Future cash inflows	$ 630,332,900	$ 408,694,869	$ 494,523,456
Future production costs	(216,584,982)	(135,516,703)	(146,168,829)
Future development and asset retirement costs	(50,572,218)	(35,290,260)	(45,269,686)
Future income tax expense	(131,397,192)	(83,543,516)	(107,111,317)
Future net cash flows	231,778,508	154,344,390	195,973,624
10% annual discount	(130,103,612)	(86,930,102)	(117,591,190)
Standardized measure of discounted future net cash flows	$ 101,674,896	$ 67,414,288	$ 78,382,434

Changes in the standardized measure of discounted future net cash flows are as follows:

	2013	2012	2011
Beginning of year	$ 67,414,288	$ 78,382,434	$ 72,500,409
Changes resulting from:			
Sales of oil, NGL and natural gas, net of production costs	(46,909,635)	(30,226,927)	(33,570,621)
Net change in sales prices and production costs	47,270,404	(45,178,377)	(2,697,833)
Net change in future development and asset retirement costs	(7,363,224)	4,483,543	4,126,812
Extensions and discoveries	54,101,830	34,216,533	11,938,029
Revisions of quantity estimates	(3,150,420)	(27,419,576)	7,046,873
Acquisitions (divestitures) of reserves-in-place	2,198,612	20,160,327	4,480,858
Accretion of discount	11,473,819	13,644,203	12,523,091
Net change in income taxes	(27,464,341)	10,735,694	(5,329,092)
Change in timing and other, net	4,103,563	8,616,434	7,363,908
Net change	34,260,608	(10,968,146)	5,882,025
End of year	$ 101,674,896	$ 67,414,288	$ 78,382,434

12. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

The following is a summary of the Company's unaudited quarterly results of operations.

	Fiscal 2013 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 14,180,435	$ 12,581,986	$ 17,730,445	$ 18,396,254
Income (loss) before provision for income taxes	$ 2,825,298	$ 1,761,487	$ 7,323,168	$ 8,780,096
Net income (loss)	$ 2,148,298	$ 1,022,487	$ 5,070,168	$ 5,719,096
Earnings (loss) per share	$ 0.26	$ 0.12	$ 0.61	$ 0.68

	Fiscal 2012 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 13,404,333	$ 10,436,910	$ 13,649,692	$ 11,041,382
Income (loss) before provision for income taxes	$ 4,261,110	$ 1,205,966	$ 4,681,299	$ 496,621
Net income (loss)	$ 3,412,110	$ 675,966	$ 3,100,299	$ 182,621
Earnings (loss) per share	$ 0.41	$ 0.08	$ 0.37	$ 0.02

ITEM 9 CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

NONE

ITEM 9A CONTROLS AND PROCEDURES

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Company maintains "disclosure controls and procedures," as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including the Company's President/CEO and Vice President/CFO, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. The Company's disclosure controls and procedures have been designed to meet, and management believes that they do meet, reasonable assurance standards. Based on their evaluation as of the end of the fiscal period covered by this report, the Chief Executive Officer and Chief Financial Officer have concluded that, subject to the limitations noted above, the Company's disclosure controls and procedures were effective.

(b) MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's management is responsible for establishing and maintaining adequate "internal control over financial reporting," as such term is defined in Exchange Act Rule 13a-15(f). The Company's management, including the President/CEO and Vice President/CFO, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the Company's management concluded that its internal control over financial reporting was effective as of September 30, 2013.

(c) CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in the Company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting made during the fiscal quarter ended September 30, 2013, or subsequent to the date the assessment was completed.

ITEM 9B OTHER INFORMATION

None

PART III

The information called for by Part III of Form 10-K (Item 10 - Directors and Executive Officers of the Registrant, Item 11 - Executive Compensation, Item 12 - Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 13 - Certain Relationships and Related Transactions, and Item 14 - Principal Accountant Fees and Services), is incorporated by reference from the Company's definitive proxy statement, which will be filed with the SEC within 120 days after the end of the fiscal year to which this report relates.

PART IV

ITEM 15 EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

FINANCIAL STATEMENT SCHEDULES

The Company has omitted all schedules because the conditions requiring their filing do not exist or because the required information appears in the Company's Financial Statements, including the notes to those statements.

EXHIBITS

(3)	Amended Certificate of Incorporation (incorporated by reference to Exhibit attached to Form 10 filed January 27, 1980, and to Forms 8-K dated June 1, 1982, December 3, 1982, to Form 10-QSB dated March 31, 1999, and to Form 10-Q dated March 31, 2007)
	By-Laws as amended (incorporated by reference to Form 8-K dated October 31, 1994)
	By-Laws as amended (incorporated by reference to Form 8-K dated February 24, 2006)
	By-Laws as amended (incorporated by reference to Form 8-K dated October 29, 2008)
	By-Laws as amended (incorporated by reference to Form 8-K dated August 2, 2011)
(4)	Instruments defining the rights of security holders (incorporated by reference to Certificate of Incorporation and By-Laws listed above)
*(10.1)	Agreement indemnifying directors and officers (incorporated by reference to Form 10-K dated September 30, 1989, and Form 8-K dated June 15, 2007)
*(10.2)	Agreements to provide certain severance payments and benefits to executive officers should a Change-in-Control occur as defined by the agreements (incorporated by reference to Form 8-K dated September 4, 2007)
(23)	Consent of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants
(31.1)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(31.2)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(32.1)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(32.2)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(99)	Report of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants
(99.1)	Amended and Restated Credit Agreement dated November 25, 2013
(101.INS)	XBRL Instance Document
(101.SCH)	XBRL Taxonomy Extension Schema Document
(101.CAL)	XBRL Taxonomy Extension Calculation Linkbase Document
(101.LAB)	XBRL Taxonomy Extension Labels Linkbase Document
(101.PRE)	XBRL Taxonomy Extension Presentation Linkbase Document
(101.DEF)	XBRL Taxonomy Extension Definition Linkbase Document

* Indicates management contract or compensatory plan or arrangement

REPORTS ON FORM 8-K

No Form 8-K's were filed in the fourth quarter of 2013.

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

PANHANDLE OIL AND GAS INC.

By: /s/ Michael C. Coffman
Michael C. Coffman
Chief Executive Officer

Date: December 11, 2013

In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Michael C. Coffman Michael C. Coffman	President, Chief Executive Officer, Director	December 11, 2013
/s/ Lonnie J. Lowry Lonnie J. Lowry	Vice President, Chief Financial Officer	December 11, 2013
/s/Robb P. Winfield Robb P. Winfield	Controller, Chief Accounting Officer	December 11, 2013
/s/ Duke R. Ligon Duke R. Ligon	Director	December 11, 2013
/s/ Robert O. Lorenz Robert O. Lorenz	Lead Independent Director	December 11, 2013
/s/ Robert A. Reece Robert A. Reece	Director	December 11, 2013
/s/ Robert E. Robotti Robert E. Robotti	Director	December 11, 2013
/s/ Darryl G. Smette Darryl G. Smette	Director	December 11, 2013
/s/ H. Grant Swartzwelder H. Grant Swartzwelder	Director	December 11, 2013

EXHIBIT 23

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

November 20, 2013

Panhandle Oil and Gas Inc.
Grand Centre, Suite 300
5400 North Grand Blvd.
Oklahoma City, OK 73112

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to the inclusion of our Letter Report, dated October 1, 2013, as attached as Exhibit 99 to the Annual Report on Form 10-K of Panhandle Oil and Gas Inc., and to the inclusion of information from "Appraisal Report as of September 30, 2013 on Certain Properties owned by Panhandle Oil and Gas Inc." in the sections "Proved Reserves," and "Supplementary Information on Oil and Natural Gas Reserves (Unaudited)" in the Annual Report on Form 10-K of Panhandle Oil and Gas Inc.

Very truly yours,

/s/DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

EXHIBIT 31.1

__CERTIFICATION__

I, Michael C. Coffman, certify that:

1. I have reviewed this annual report on Form 10-K of Panhandle Oil and Gas Inc.;

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

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

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

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

    (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

__/s/ Michael C. Coffman__
Michael C. Coffman
Chief Executive Officer
Date: December 11, 2013

EXHIBIT 31.2

CERTIFICATION

I, Lonnie J. Lowry, certify that:

1. I have reviewed this annual report on Form 10-K of Panhandle Oil and Gas Inc.;

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

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

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

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

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

/s/ Lonnie J. Lowry
Lonnie J. Lowry
Chief Financial Officer
Date: December 11, 2013

EXHIBIT 32.1

Panhandle Oil and Gas Inc.
5400 North Grand Blvd. Suite #300
Oklahoma City, OK 73112

CERTIFICATION OF CHIEF EXECUTIVE OFFICER REGARDING PERIODIC REPORT CONTAINING FINANCIAL STATEMENTS

I, Michael C. Coffman, President and Chief Executive Officer of Panhandle Oil and Gas Inc. (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify in connection with the Company's Annual Report on Form 10-K for the period that ended September 30, 2013, as filed with the Securities and Exchange Commission (the "Report") that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in this Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Michael C. Coffman
Michael C. Coffman
President &
Chief Executive Officer

December 11, 2013

EXHIBIT 32.2

Panhandle Oil and Gas Inc.
5400 North Grand Blvd. Suite #300
Oklahoma City, OK 73112

CERTIFICATION OF CHIEF FINANCIAL OFFICER
REGARDING PERIODIC REPORT CONTAINING
FINANCIAL STATEMENTS

I, Lonnie J. Lowry, Vice President and Chief Financial Officer of Panhandle Oil and Gas Inc. (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify in connection with the Company's Annual Report on Form 10-K for the period that ended September 30, 2013, as filed with the Securities and Exchange Commission (the "Report") that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in this Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Lonnie J. Lowry
Lonnie J. Lowry
Vice President &
Chief Financial Officer

December 11, 2013

Panhandle
Oil and Gas Inc.

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