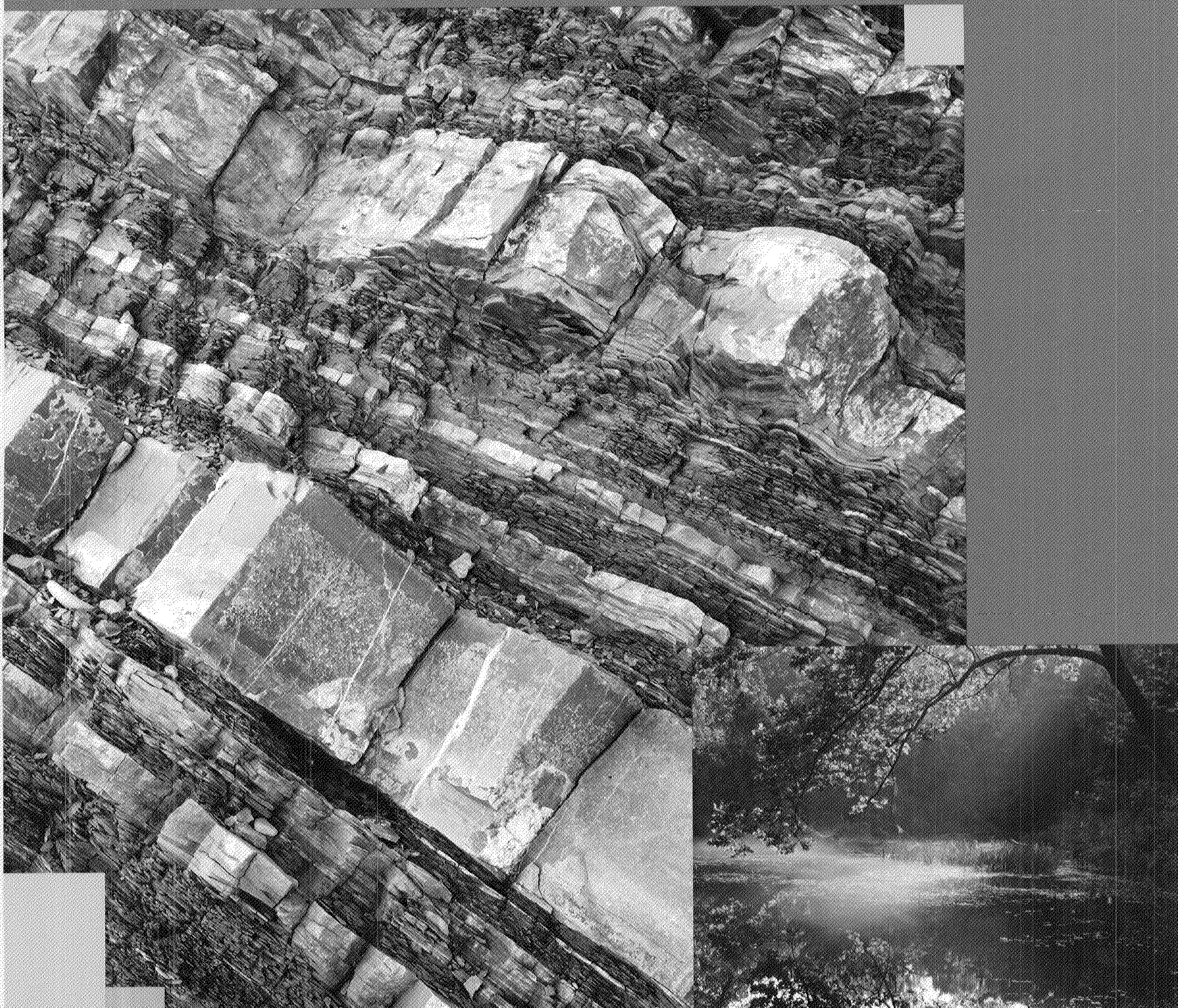
2011 Annual Report



Panhandle
Oil and Gas Inc.

For defined terms used in this report please see "Definitions" page of the attached Form 10-K.

Panhandle Oil and Gas Inc.

TO OUR SHAREHOLDERS

2011 financial and operating results once again highlighted the quality of the Company's asset base of 255,857 acres of broadly diversified perpetually owned fee minerals coupled with the unique operating strategies employed to maximize the value of those assets.

2011 HIGHLIGHTS:

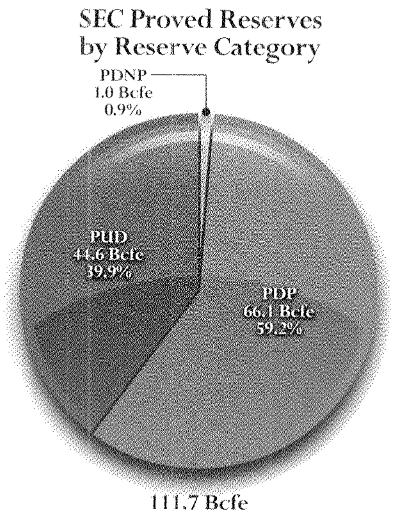
- Recorded a net income of $8,493,912 or $1.01 per share
- Increased proved reserves 8% to 111.7 Bcfe at September 30, 2011, as compared to 103.7 Bcfe at September 30, 2010
- Increased Probable and Possible reserves 4% to 299.9 Bcfe at September 30, 2011
- Grew Cash Flow From Operating Activities to $29,283,929; an increase of 5% over 2010
- Increased Capital Expenditures 144% to $27,545,348, and fully funded those expenditures from cash flow
- Re-established momentum in production growth, with fourth quarter 2011 production increasing 14% above the third quarter level
- Maintained debt free status during fiscal 2011

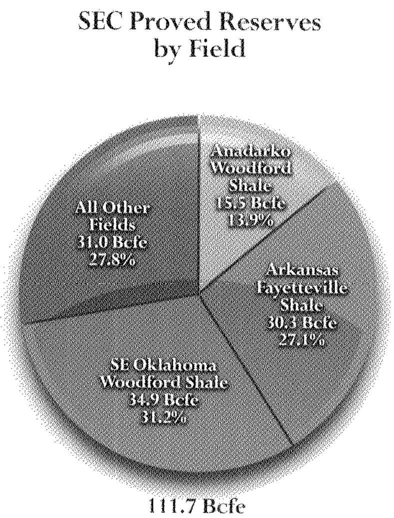
A thorough discussion of our 2011 Operational Highlights and Developments is contained on pages 3 to 7 of this report. In addition, the attached Form 10-K contains a complete discussion and analysis of the Company's financial results for fiscal 2011 on pages 24-34.

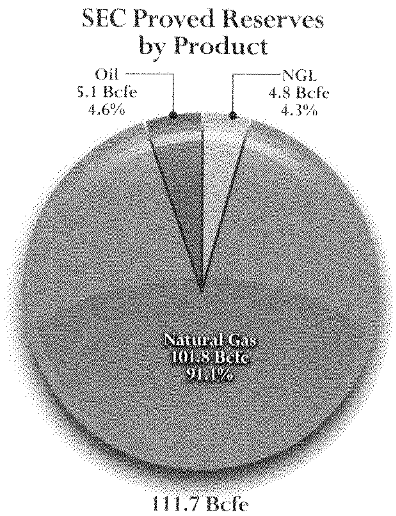
During 2011 the industry as a whole continued to shift its drilling focus to plays that produce significant volumes of natural gas liquids or oil in association with natural gas production. We were able to focus 80% of the Company's drilling dollars during the year on projects in Western Oklahoma, which we expect to yield significantly better rates of return, as compared to dry gas wells, due to the value of the associated liquids production. Western Oklahoma has many areas that have high quality horizontal drilling plays for the Cana Woodford, Granite/Atoka Wash, Cleveland, Hogshooter Wash, Marmaton and Tonkawa. Panhandle has more than 40,000 net mineral areas in Western Oklahoma that will continue to provide many years of drilling opportunity for the Company. As long as liquids and oil prices remain near current levels drilling in these plays will continue at a rapid pace.

Many of the large independent energy companies are drilling in these plays. These companies have the scientific and technical expertise to delineate these plays and then to successfully execute the drilling, completion and placing on production of these expensive and technically challenging wells. We are careful to ensure the operating companies with which we participate in drilling operations have demonstrated the ability to perform at a high level of expertise in these plays.

During the year we felt there was an opportunity developing in the Company's dry gas plays to be able to purchase assets, including mineral acres and non-operated working interests in wells, at very attractive valuations. This situation seemed to be the result of declining







natural gas prices and other factors. This opportunity was particularly available in the Fayetteville Shale play in Arkansas. The Fayetteville is the Company's lowest, on average, finding cost play and the predominant operator does an excellent job drilling and completing wells and continues to develop the play. As a result we purchased approximately $4.7 million of fee mineral acreage, principally in the Fayetteville Shale, during the last few months of the fiscal year.

Our long-term focused outlook at Panhandle and strong financial position allow us to make these investments in dry gas plays today with the expectation of increasing natural gas demand and market prices over the next few years. These investments, made based on today's natural gas prices, will allow the Company to earn acceptable rates of return on its investments and, as additional wells are drilled on the acquired properties and natural gas prices recover over the next few years, significantly increase these rates of return.

LOOKING FORWARD:

We expect the above acquisition opportunities to continue into fiscal 2012. In fact, on October 25, 2011, we closed on the purchase of interests in 193 non-operated natural gas wells and 1,531 acres of leasehold in the Fayetteville Shale. More than 80% of the leasehold is held-by production, and we have identified approximately 240 future infill drilling locations on the properties. This $17.5 million acquisition was funded by a combination of cash-on-hand and borrowing on the Company's line of credit. Production and reserves from this acquisition will be reflected by the Company beginning in the first fiscal quarter of 2012. Expected production from these properties will increase daily production by approximately 12%.

Drilling expenditures during the coming year will continue to be focused on the Western Oklahoma plays outlined above and discussed extensively in the Operational Highlights. Further, we expect to continue our acquisition efforts, particularly in the Fayetteville Shale where low finding costs coupled with improving well performance make this play, in our opinion, one of the best shale gas plays in the country.

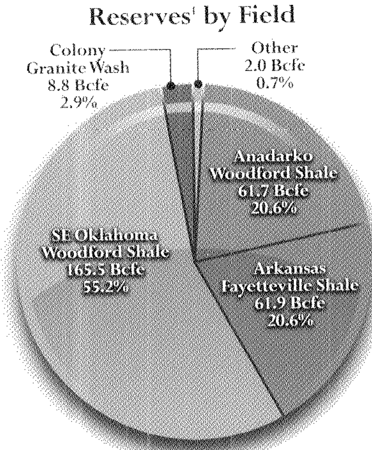
As always your management will be looking for ways to continue to maximize the value of each share of Panhandle stock by using the built-in capital efficiency of drilling on owned mineral acres, by growing reserves and by increasing production of oil, natural gas liquids and natural gas. We will continue to follow a prudent and steady course which has proven to be successful for Panhandle over the 85-year history of the Company.

2011 OPERATIONAL HIGHLIGHTS AND DEVELOPMENTS

Fiscal year 2011 (2011) was a year of significant transition for Panhandle Oil and Gas as we continued to shift the focus of our capital investments from dry gas plays to more complex oil and natural gas liquids bearing reservoirs in Western Oklahoma and the Texas Panhandle. The Company allocated approximately 80% of FY 2011 approved drilling capital expenditures to these relatively new plays, which involve horizontal drilling in the Granite Wash, Hogshooter Wash, Cleveland, Marmaton and Tonkawa and the Anadarko Basin "Cana" Woodford Shale. This shift is the result of the persistent value disparity between relatively low natural gas prices compared to high oil and natural gas liquids prices. Because we own perpetual mineral positions in the dry gas Southeastern Oklahoma Woodford Shale (SE OK Woodford), our undeveloped reserves in that play will remain intact, and we will be prepared to develop those reserves when natural gas market conditions are more favorable. Activity in the dry gas Arkansas Fayetteville Shale (Fayetteville) has remained reasonably consistent as the development of those reserves continues to generate reasonable returns in the current gas price environment. Through this transition we have maintained our core principle of maximizing long term shareholder value through optimized development of our extensive and diverse mineral holdings.

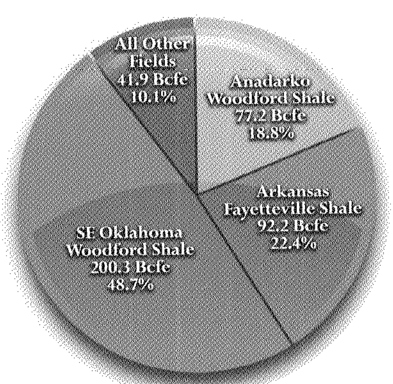
Our experienced technical team – consisting of two geologists, two petroleum landmen and a petroleum engineer – performs detailed technical and economic evaluations of each well proposal we receive. The analysis includes assessment of various risk factors including geologic, reserve, product price, operator competency and mechanical risk. These risked economics are based solely on the projected investment by Panhandle and projected revenues generated by that investment. The royalty revenue that we will receive by virtue of owning the minerals, irrespective of our working interest participation, is not considered in our investment analysis. Management utilizes this analysis to allocate capital with the objective of maximizing the return on our capital investments, while preserving the Company's future opportunity on our mineral holdings. Based on these assessments, the Company elected to participate with a working interest in 72% of the well proposals we

Probable & Possible Reserves[1] by Field



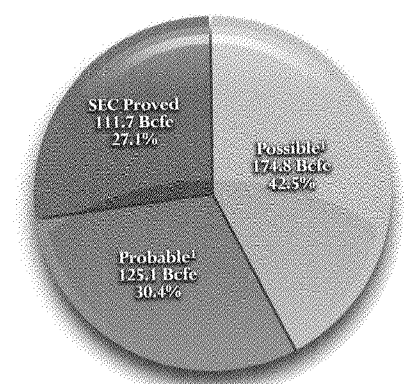
299.9 Bcfe

Proved, Probable and Possible Reserves by Field



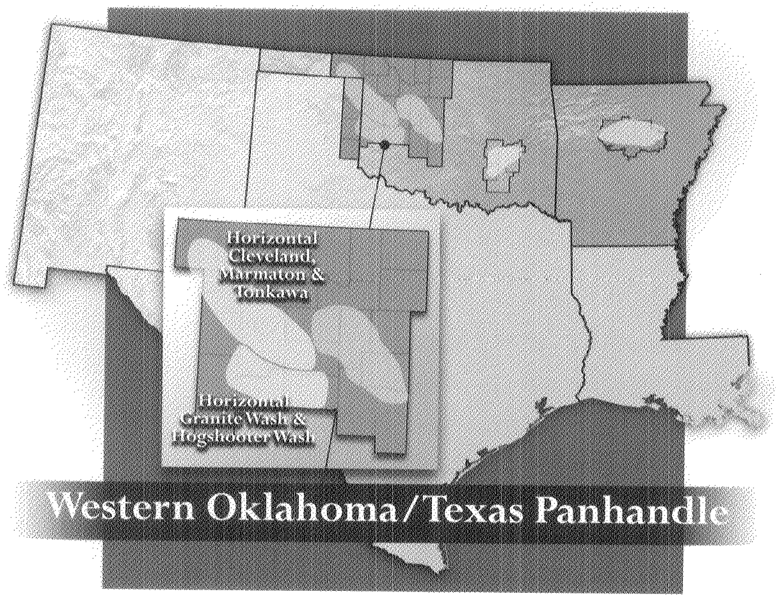
411.6 Bcfe

Proved, Probable and Possible Reserves by Reserve Category



411.6 Bcfe

[1] Prepared in accordance with Petroleum Resources Management System



received in 2011. We leased our mineral acreage in the remaining projects, which we deemed would not yield acceptable rates of return for Panhandle. These leased mineral acres will generate non-cost-bearing royalty revenue and production for the Company where production is established.

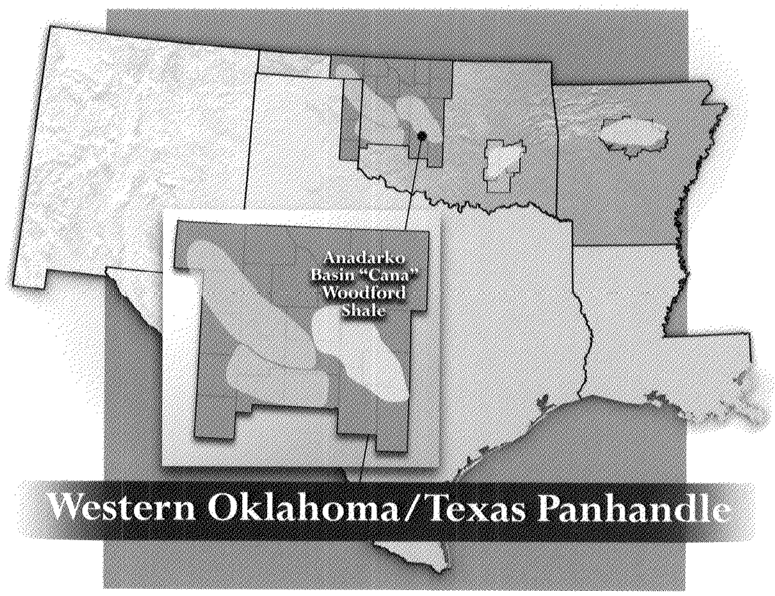
The successful execution of this strategy has resulted in the Company's continued ability to generate earnings during this extended period of relatively low gas prices. It has also resulted in expansion of the Company's reserve base at attractive finding and development costs.

At September 30, 2011, proved reserves increased 8% to a record 111.7 Bcfe, while proved, probable and possible (3P) reserves increased to a record 411.6 Bcfe. In addition to the proved and 3P reserve growth, the quality of these reserves was substantially enhanced. The percentage of proved and probable reserves increased to 57.5% of total 3P reserves versus 48.8% of total 3P reserves at September 30, 2010. Reserve quality was also significantly enhanced by the recognition of natural gas liquids reserves for the first time in the 2011 reserve report. Oil and natural gas liquids now account for approximately 9% of the Company's proved reserves; however, these products now account for approximately 24% of the Company's revenue.

In mid-2011 the Company began actively acquiring mineral interests and producing properties in its dry gas resource plays due to the extremely attractive market prices for these types of assets. The opportunity for Panhandle appears to result from persistent low natural gas prices, as well as a current lack of demand for property in this particular niche of the market. To date Panhandle has acquired 1,554 acres of minerals and leasehold, predominately in the Fayetteville Shale. We believe these acquisitions will create substantial long-term opportunities to earn attractive rates of return for Panhandle, and we expect to continue this program as long as attractively priced assets are available.

WESTERN OKLAHOMA

The foundation of Panhandle Oil and Gas is its mineral position in Western Oklahoma where the Company's holdings exceed 40,000 net mineral acres. In FY 2011, the Company allocated approximately 46% of its approved capital expenditures to development of this oil and natural gas liquids-rich area. Brisk development continued in the horizontal Granite Wash play where Panhandle owns approximately 10,400 acres in the potential development area. Panhandle is also participating in the rapid development of the new and highly productive Hogshooter Wash play within the boundaries of the Granite Wash development area and is involved

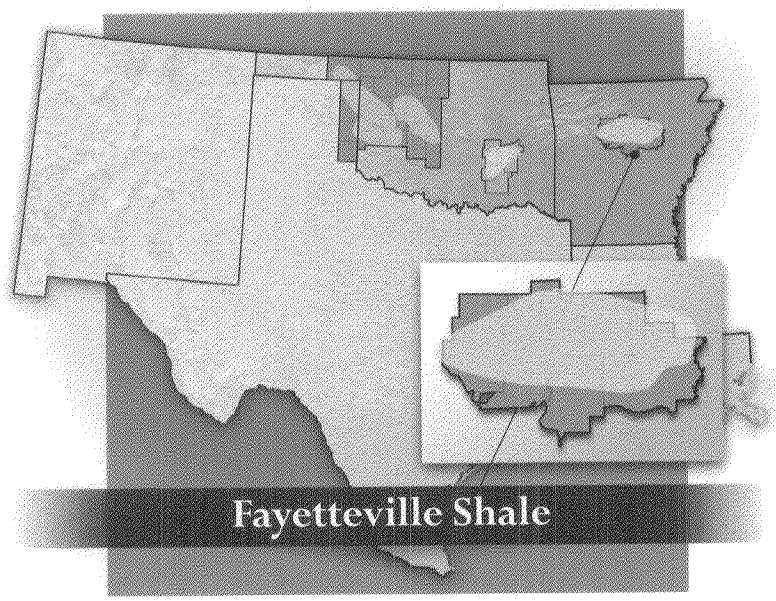


in successful horizontal development of the Cleveland, Tonkawa and Marmaton formations in Western Oklahoma. Each of these plays differs materially from the shale gas resource plays that have been the Company's focus for the last several years. These various oil and natural gas liquids-rich plays generally consist of multiple localized deposits of sandstone, limestone or wash reservoirs as opposed to the widespread relatively uniform distribution of the shale gas resources over multiple counties. These reservoirs are generally significantly more permeable than the shale reservoirs and therefore have the ability to produce at substantially higher rates. The combination of the high relative value associated with oil and natural gas liquids, plus the potential for exceptionally high production rates has resulted in the surge of activity in these plays. This offers significant opportunity for Panhandle given our substantial legacy acreage position, which was acquired over a period of many years for a nominal cost. However, this opportunity comes with increased geologic and economic risk as these plays are substantially more complex, and the results are more difficult to predict, than in the development of our shale gas assets. The Company is managing this risk by allocating the bulk of its technical staff to the study and analysis of these plays. We are participating as a working interest owner in those proposed drilling opportunities that meet our rate of return targets after considering the project's risk, and we are leasing our mineral acreage in the remainder. This approach is expected to yield excellent returns for Panhandle since, in theory, we will be participating with a working interest in the high-return opportunities while also benefiting from the cost-free royalty revenue from the rest. Management anticipates that Western Oklahoma oil and natural gas liquids development will continue through FY 2012, and we are committed to participating in all opportunities deemed to meet out risk-weighted rate of return target.

ANADARKO BASIN "CANA" WOODFORD SHALE

Panhandle owns approximately 3,545 acres of mineral and leasehold interest in the expanded Cana Woodford play. These interests generate an average net revenue interest of approximately 2.5% across 135 separate sections. Panhandle also owns an attractive mineral position in areas of further potential play expansion.

There were two focused areas of activity in the Cana Woodford play in 2011: continued drilling in the core of the play as operators moved to hold their leases by establishing production and the expansion of the play to the northwest in western Blaine and Dewey counties, Oklahoma. The core of the Cana Woodford play is located in Canadian, Blaine and Caddo counties, Oklahoma where the Woodford shale is approximately



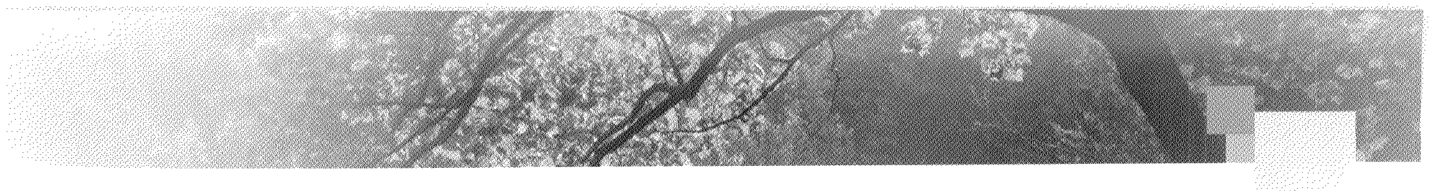
150 feet thick or greater. This play is unique because it is one of the deepest shale resource plays in North America. The reservoir also has abnormally high pressure, which translates into very high amounts of gas reserves in place, and the gas produced has a high natural gas liquid content. The core of this play has been established as a world-class, natural gas liquids-rich resource play with full development anticipated to occur during the next several years as natural gas and natural gas liquids prices justify. Drilling in the northwest expansion of the play, outside the core, was significant during 2011. However, well results were mixed, and it appears that the industry is re-evaluating the area to determine if it can be economically developed. As a result, Panhandle's probable and possible reserve assessment in that area of the play was reduced at year-end.

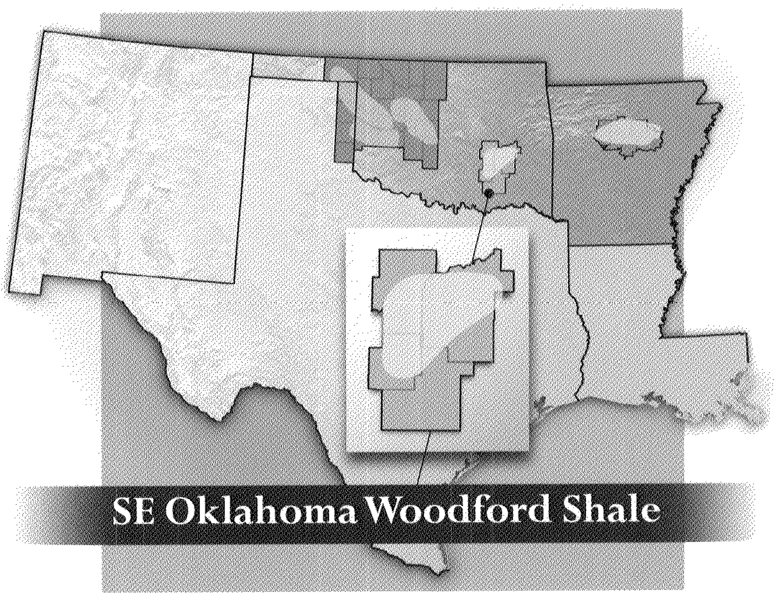
Management anticipates significant drilling activity will continue in the core of this play during fiscal 2012 and beyond. Panhandle is committed to participating in those attractive opportunities.

ARKANSAS FAYETTEVILLE SHALE

Panhandle owns approximately 10,120 acres of net mineral and leasehold interest in the core of the play. These interests are extremely well diversified across the play with an average net revenue interest of approximately 2.2% in 249 separate sections. The play is located in Cleburne, Conway, Faulkner, Pope, Van Buren and White counties, Arkansas.

The Fayetteville has developed into one of North America's lowest-cost dry gas shale resource plays. This is largely due to its relatively shallow depth and resulting low cost to drill coupled with exceptional well productivity. The major operators in this play continue to increase operating efficiency while optimizing well performance. This has resulted in an extremely low cost structure, which has allowed development to remain profitable even at today's low natural gas prices. Activity remains relatively constant, and Panhandle participated with a working interest in every drilling proposal received in the play in FY 2011. Management anticipates this play will continue to generate favorable returns in 2012 and beyond, and we are committed to continued participation in these attractive opportunities. The Fayetteville will become the highest producing play for the Company in FY 2012.





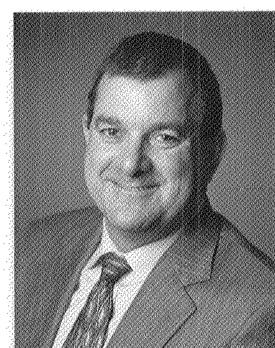
SOUTHEASTERN OKLAHOMA WOODFORD SHALE

Panhandle owns approximately 6,518 acres of net mineral interest in the core of this play. These interests are extremely well diversified across the play with an average net revenue interest of approximately 3.3% across 210 separate sections. For several years the Southeast Oklahoma Woodford play (Woodford) was Panhandle's largest asset in terms of current production and reserves. This play continues to be an excellent dry gas resource play in Panhandle's asset portfolio. The play is located in Atoka, Coal, Hughes and Pittsburg counties, Oklahoma.

While activity in this play was generally limited to the best areas of the play primarily in the northern portion of the core where the Woodford is shallow, drilling costs are low and well performance is exceptional. Management anticipates activity in this play will generally be limited to these areas until natural gas prices recover to a level that will generate reasonable rates of return in the remainder of the play.

The Company is committed to participating in those attractive opportunities. Since we own perpetual mineral positions in the SE OK Woodford play, our undeveloped reserves in the other areas of the play will remain intact, and we are prepared to continue development of those reserves when market conditions are more favorable.

Michael C. Coffman
President
Chief Executive Officer



Paul Blanchard
Senior Vice President
Chief Operating Officer

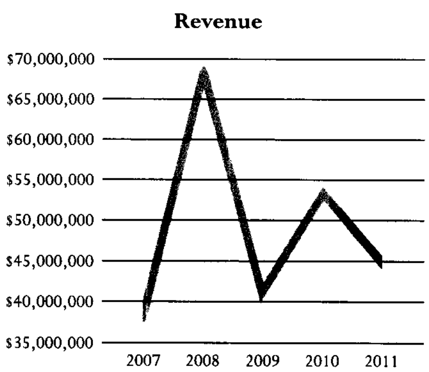
FINANCIAL AND OPERATING HIGHLIGHTS

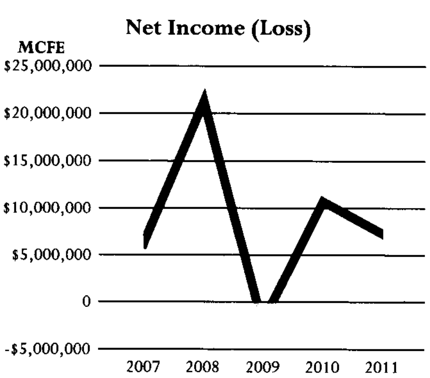
	2011	2010	2009
Revenue and Earnings			
Revenue	$ 44,976,651	$ 51,938,416	$ 37,272,614
Net Income (loss)	$ 8,493,912	$ 11,419,690	$ (2,405,021)
Earnings (loss) per Share	$ 1.01	$ 1.36	$ (.29)
Average Shares Outstanding	8,393,890	8,422,387	8,397,337
Net Cash Provided by Operating Activities	$ 29,283,929	$ 27,806,475	$ 37,710,606
Costs Incurred In Oil and Gas Activities	$ 27,289,121	$ 11,958,024	$ 28,441,399
Debt	$ 0	$ 0	$ 10,384,722

	2011	2010	2009
Production			
MCFE Produced	8,922,503	8,916,616	9,878,948
Increase (Decrease) from Prior Year	–	(10%)	28%
Average Sales Price per MCFE	$ 4.87	$ 4.94	$ 3.79
Barrels Produced	104,141	102,379	128,160
Average Sales Price per Barrel	$ 88.00	$ 72.83	$ 51.79
MCF Produced	8,297,657	8,302,342	9,109,988
Average Sales Price per MCF (1)	$ 4.13	$ 4.41	$ 3.38
Average Production Costs (per mcf equivalent) (2)	$ 1.11	$ 1.08	$ .90

(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.
(2) Production costs include well operating costs, production taxes and handling, marketing and other fees paid on natural gas sales.

In 2011, Panhandle participated in 158 wells with a working interest and had a royalty interest in 208 wells that were either completed, drilling or testing at year end.





WORKING INTEREST WELLS

Category	2011	2010	2009
Drilling	10	11	4
Testing	32	21	18
Producing	114	62	142
	(20 oil, 94 gas)	(4 oil, 58 gas)	(10 oil, 132 gas)
Dry Holes	2	1	4
Total	158	95	168

ROYALTY INTEREST WELLS

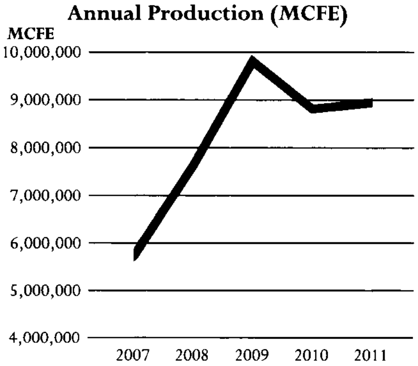
Category	2011	2010	2009
Drilling, Testing	6	8	18
Producing	202	181	255
	(29 oil, 173 gas)	(22 oil, 159 gas)	(27 oil, 228 gas)
Dry Holes	0	0	11
Total	208	189	284

RESERVES AND PRODUCTION

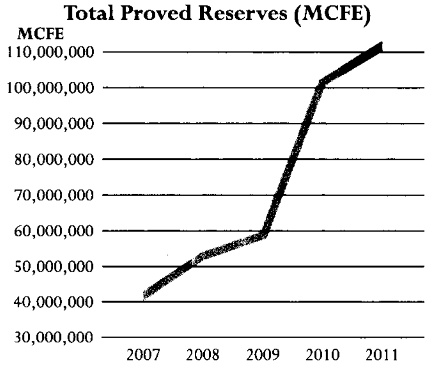
	2011	2010	2009
Reserves			
Proved Developed Reserves:			
Barrels of NGL (1)	386,774	–	–
Barrels of Oil	759,989	861,240	882,987
MCF of Gas	60,193,878	57,344,190	45,036,460
MCFE	67,074,456	62,511,630	50,334,382
Proved Undeveloped Reserves:			
Barrels of NGL (1)	404,874	–	–
Barrels of Oil	83,749	63,769	37,886
MCF of Gas	41,644,106	40,826,265	8,991,350
MCFE	44,575,844	41,208,879	9,218,666
Total Proved Reserves:			
Barrels of NGL (1)	791,648	–	–
Barrels of Oil	843,738	925,009	920,873
MCF of Gas	101,837,984	98,170,455	54,027,810
MCFE	111,650,300	103,720,509	59,553,048
Increase over prior year	8%	74%	10%
10% Discounted Estimated Future Net Cash Flows (before federal income taxes @ SEC pricing)			
Proved Developed	$ 106,464,138	$ 103,270,565	$ 73,869,512
Proved Undeveloped	29,977,891	21,960,347	6,800,080
Total	$ 136,442,029	$ 125,230,912	$ 80,669,592
SEC Pricing			
NGL/Barrel	$ 38.91	$ –	$ –
Oil/Barrel	$ 90.28	$ 69.23	$ 66.96
Gas/MCF	$ 3.81	$ 4.33	$ 2.86

(1) 2011 is 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 Oklahoma, 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)



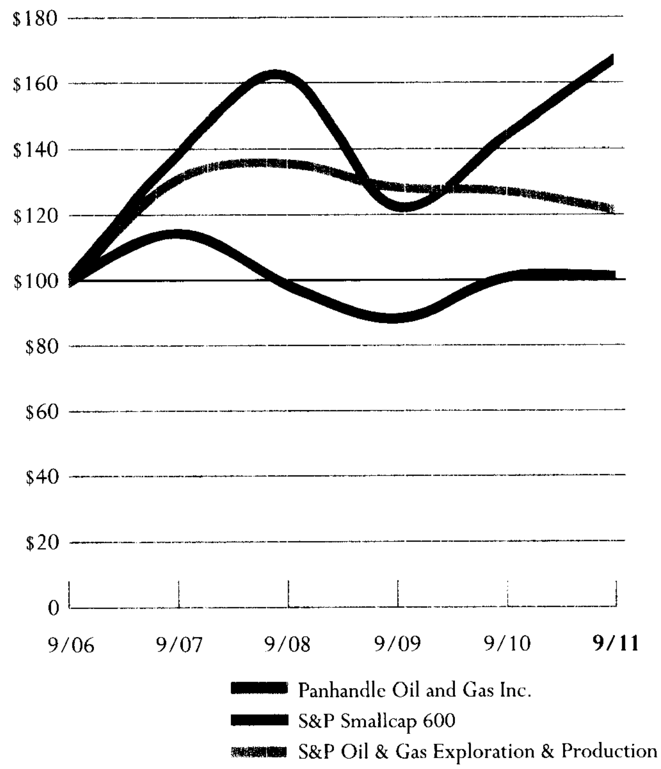
Total Proved Reserves (MCFE)



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 9/30/2006 and tracks it through 9/30/2010.



* $100 invested on 9/30/06 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, 2009	$ 26.25	$ 19.06
March 31, 2010	$ 29.65	$ 20.34
June 30, 2010	$ 29.29	$ 21.97
September 30, 2010	$ 30.31	$ 21.00
December 31, 2010	$ 28.70	$ 23.75
March 31, 2011	$ 31.88	$ 25.60
June 30, 2011	$ 32.50	$ 27.30
September 30, 2011	$ 36.25	$ 26.36

As of November 22, 2011, there were 1,592 holders of record of Panhandle's Class A Common Stock and approximately 4,200 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, 2011, 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 2011 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.

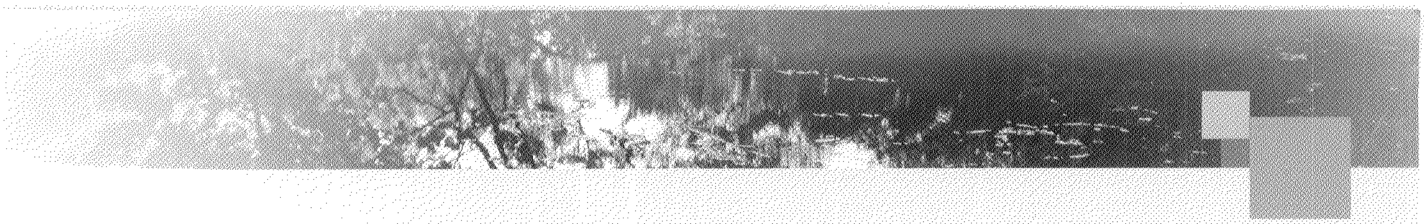
During the past two years, cash dividends have been declared and paid as follows on the Class A Common Stock:

Date	Rate Per Share
December 2009	$ 0.07
March 2010	$ 0.07
June 2010	$ 0.07
September 2010	$ 0.07
December 2010	$ 0.07
March 2011	$ 0.07
June 2011	$ 0.07
September 2011	$ 0.07

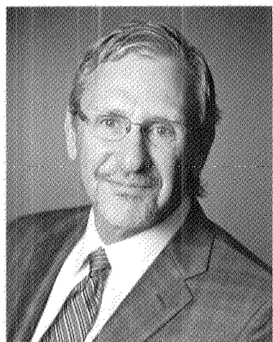
While the Company expects to continue to pay dividends on its Common Stock, the payment of future cash dividends will depend upon, among other things, financial condition, funds from operations, the level of capital and development expenditures, future business prospects, contractual restrictions and 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

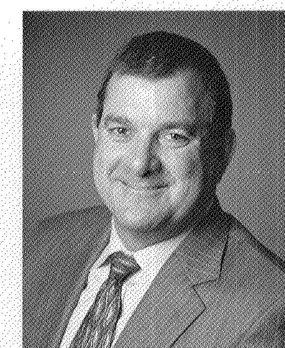
May 1982	10-for-1
May 1999	3-for-1
February 2004	2-for-1
January 2006	2-for-1



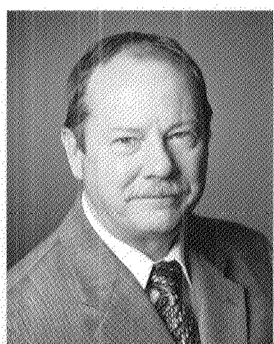
OFFICERS



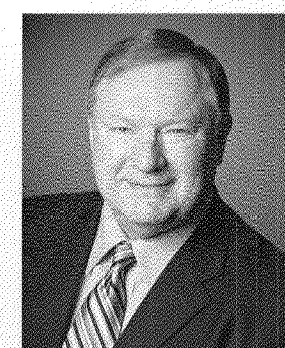
Michael C. Coffman
President
Chief Executive Officer



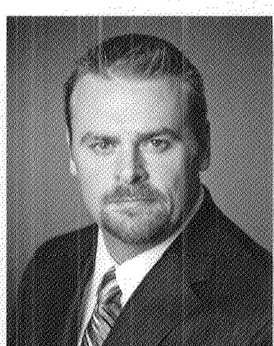
Paul Blanchard
Senior Vice President
Chief Operating Officer



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.
Tulsa, 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
1-781-575-4706

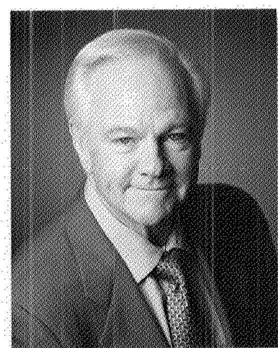
Website:

www.computershare.com

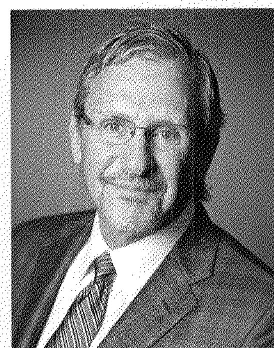
Email inquiry address for investors:

web.queries@computershare.com

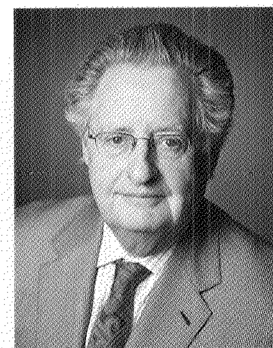
BOARD OF DIRECTORS



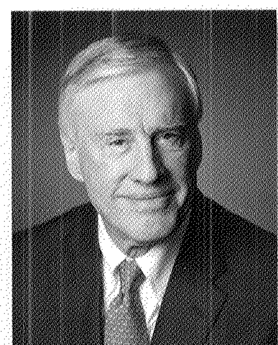
Bruce M. Bell
Edrio Oil Company
(2) (4)



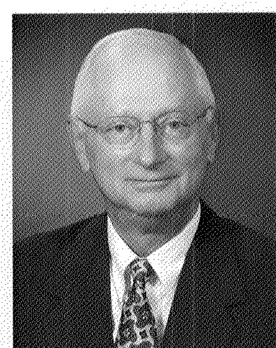
Michael C. Coffman
President
Chief Executive Officer



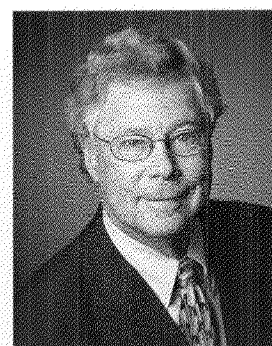
E. Chris Kauffman
Campbell-Kauffman
Insurance Agency
(2) (3)



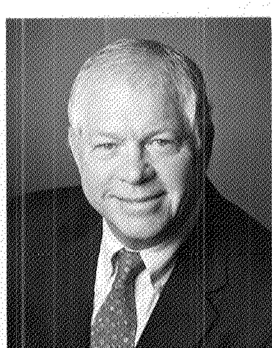
Duke R. Ligon
Attorney
(1) (4)



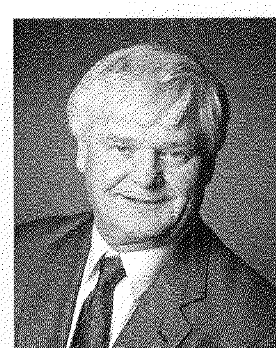
Robert O. Lorenz
Lead Independent Director
(1) (2)



Robert A. Reece
Attorney
(1) (3)



Robert E. Robotti
Robotti & Company, LLC
(1) (2)



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

H. Grant Swartzwelder
PetroGrowth Advisors
(3) (4)

(1) Member audit committee
(2) Member compensation committee
(3) Member retirement committee
(4) 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, 2011

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 closing price of registrant's Common Stock, at March 31, 2011, was $223,251,282. As of December 1, 2011, 8,256,171 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 8, 2012, 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;

"Board" means board of directors;

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

"CEO" means Chief Executive Officer;

"CFO" means Chief Financial Officer;

"CO2" means carbon dioxide;

"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;

"gross wells" or **"gross acres"** are the wells or acres in which the Company has a working or royalty interest;

"Independent Consulting Petroleum Engineer(s)" or **"Independent Consulting Petroleum Engineering Firm(s)"** refers to DeGolyer and MacNaughton of Dallas, Texas, for proved reserves calculated as of September 30, 2010 and 2011, or to Pinnacle Energy Services, L.L.C. of Oklahoma City, Oklahoma, for proved reserves calculated as of September 30, 2009;

"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;

"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"** refers to fee mineral acreage owned in perpetuity by the Company;

"net wells" or **"net acres"** are determined by multiplying gross wells or acres by the Company's net revenue interest in such wells or acres;

"NGL" means natural gas liquids;

"NYMEX" refers to the New York Mercantile Exchange;

"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 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" means 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 2011 mean the fiscal year ended September 30, 2011.

References to natural gas

Excluding 2011 reserves, all references to natural gas reserves, production, sales and prices include associated natural gas liquids.

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

PART I

ITEM 1 BUSINESS

GENERAL

Panhandle Oil and Gas Inc. ("Company" or "Panhandle") 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.

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

The Company is involved in the acquisition, management and development of 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 and natural gas production is from wells located in Oklahoma.

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 its website as soon as reasonably practicable after they are filed with the SEC. 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, more than 85% of Panhandle's revenues are derived from the production and sale of oil and natural gas (see Item 8 - "Financial Statements"). 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 – "Description of 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 properties and on third-party drilling prospects. A significant percentage of the Company's recent drilling participations have been on properties in which the Company owns mineral acreage and, in many cases, already owns an interest in a producing well in the unit. Most of these wells are in unconventional plays (shale gas) located in Oklahoma and Arkansas.

PRINCIPAL PRODUCTS AND MARKETS

The Company's principal products are natural gas and, to a lesser extent, crude oil and natural gas liquids. 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 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 sold is received by the Company either from the contracted purchasers or the well operator. 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 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 the Organization of Petroleum Exporting Countries ("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 to 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 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 is contained in Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

COMPETITIVE BUSINESS CONDITIONS

The oil and natural gas industry is highly competitive, particularly in the search for new oil 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, changes in prices received for its oil and natural gas production, business and consumer demand for refined oil products and natural gas, and the effects of federal and state regulation of the exploration for, production of and sales of oil 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 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 uses its strong financial base and its mineral and leasehold acreage ownership, coupled with its own geologic and economic evaluations, to participate in drilling operations with these larger companies. This methodology allows the Company to compete effectively in drilling operations it could not undertake on its own due to financial and personnel limits and allows it to maintain low overhead costs.

SOURCES AND AVAILABILITY OF RAW MATERIALS

The existence of recoverable oil 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 the raw materials to our business. The production and sale of oil and natural gas from the Company's properties is 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, drilling and development operations and, subsequently, the production and sale of oil and natural gas. This participation in exploration 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 and natural gas production is sold, in most cases, through its well operators to many different purchasers on a well-by-well basis. During 2011, sales through two separate well operators accounted for approximately 15% and 14% of the Company's total oil and natural gas sales. During 2010, sales through three separate well operators accounted for approximately 15%, 14% and 11% of the Company's total oil and natural gas sales. During 2009, sales through three separate well operators accounted for approximately 20%, 17% and 14% of the Company's total oil 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 producing oil and natural gas wells 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 and/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 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 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. These changes were intended by FERC 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.

More recently, 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 and that, absent an extraordinary event, any noncompliance will not 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, 2011, Panhandle employed 19 persons on a full-time basis with five of the employees serving as executive officers. The President and CEO is also a director of the Company.

RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating the Company's business and future prospects. The risk factors described below are not necessarily 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.

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

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

Oil 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.

Oil and natural gas prices have historically been and will likely continue to be volatile. The prices for oil and natural gas are subject to wide fluctuation in response to a number of factors, including:

- worldwide economic conditions;
- economic, political and regulatory developments;
- market uncertainty;
- relatively minor changes in the supply of and demand for oil and natural gas;
- availability and capacity of necessary transportation and processing facilities;
- commodity futures trading;
- weather conditions;
- political instability or armed conflicts in major oil and natural gas producing regions, particularly the Middle East and West Africa;
- actions taken by OPEC;
- competition from alternative sources of energy; and
- technological advancements affecting energy consumption and energy supply.

In recent years, oil and natural gas price volatility has been severe. 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 us. 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 and profitability may fluctuate significantly as a result of variations in oil and natural gas prices and production performance.

Lower oil and natural gas prices may also trigger significant impairment write-downs on a portion of the Company's properties.

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

A substantial decline in oil and natural gas prices for an extended period of time would have a material adverse effect on the Company's financial position, results of operations, access to capital and the quantities of oil and natural gas that may be economically produced. A significant decrease in price levels for an extended period would have a material negative effect in several ways, including:

- cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves 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 both lower proved reserves and cash flow; and
- access to sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable.

We cannot control activities on properties we do 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 operations of these properties or their associated costs. Our 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 success and timing of drilling, development and exploitation activities on properties operated by others depend on a number of factors that are beyond the Company's control, including the operator's expertise and financial resources, approval of other participants for drilling wells and utilization of appropriate technology.

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. Also, the fair value of our oil and natural gas derivative contracts may vary significantly from period to period, therefore materially affecting reported earnings.

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.

The fair value of our oil and natural gas derivative instruments outstanding as of September 30, 2011, was a net asset of $215,940.

Lower oil and natural gas prices or negative adjustments to oil 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 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 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 and natural gas sales prices or unfavorable adjustments to oil and natural gas reserves. 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.

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

It is not possible to measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and 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 certain assumptions that may prove to be incorrect, including assumptions relating to the level of oil and natural gas prices, future production levels, capital expenditures, operating and development costs, the effects of regulation and availability of funds. If these assumptions prove to be incorrect, our estimates of reserves (the economically recoverable quantities of oil and natural gas attributable to any particular group of properties), 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 is calculated using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month oil and natural gas price for each month within the 12-month period prior to September 30, 2011, held flat over the life of the properties and costs in effect as of the date of estimation, less future development, production and income tax expenses, and is discounted at ten percent 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 we make 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 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 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 ten percent discount factor we use when calculating discounted future net cash flows in compliance with the Financial Accounting Standards Board's ("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. The above activities are conducted with well operators, as the Company does not operate any of its wells. Future oil and natural gas production is therefore highly dependent upon the level of success in acquiring or finding additional 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 the operators' seismic data and other advanced technologies in identifying prospects and in conducting exploration and development activities. The seismic data and other technologies used do not allow operators to know conclusively prior to drilling a well whether oil or natural gas is present and may be commercially produced.

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, adverse weather conditions, environmental and other governmental requirements, the cost and availability of drilling rigs, equipment and services and the expected sales price to be received for oil 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 and explosions, pipe failures, fires, abnormal pressures, uncontrollable flows of oil and natural gas, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks.

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 it against all operational and environmental risks. For example, the Company does not maintain business interruption insurance. 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 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. The facility, which was undrawn at September 30, 2011, has a 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 will not be available for other purposes;
- covenants contained in the Company's borrowing agreement may limit our ability to borrow additional funds and pay dividends;
- 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; and
- a significant increase in the interest rate on our credit facility will limit funds available for other purposes.

The borrowing base of our corporate revolving bank credit facility is subject to periodic redetermination and is based in part on oil and natural gas prices. A lowering of our borrowing base because of lower oil or natural gas prices or for other reasons could require us to repay indebtedness in excess of the 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 economic conditions, prices and financial, business and 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 an adverse effect on our business.

<u>Federal Income Taxation</u>

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.

<u>Hydraulic Fracturing</u>

The vast majority of oil and natural gas wells drilled in recent years, and future wells expected to be drilled, in which the Company owns an interest were, or are expected to be, hydraulically fractured as a part of the process of completing the wells and putting them on production. Some members of Congress have proposed legislation to either ban or further regulate the hydraulic fracturing process. We cannot predict whether any such legislation will be enacted or, if enacted, what its provisions would be. If legislation is passed to ban hydraulic fracturing, the number of wells drilled in the future will most likely drop dramatically, and the economic performance of those drilled will be negatively affected. Legislation imposing further regulation of hydraulic fracturing may result in increased costs to drill, complete and operate wells, as well as delays in obtaining permits to drill wells.

<u>Climate Change</u>

The EPA has proposed regulations for the purpose of restricting greenhouse gas emissions from stationary sources. Such regulatory and legislative proposals to restrict greenhouse gas emissions, or to generally address climate change, could increase the Company's operating costs as operators of wells, in which the Company owns a working interest, incur costs to comply with new rules. The increase in costs to the well operators, and ultimately the Company, as a working interest owner, could include new or increased costs to install new emissions control equipment, operate and maintain existing equipment, obtain allowances to authorize greenhouse gas emissions and pay greenhouse gas related taxes. There also could be an adverse effect on demand for oil and natural gas in the market place.

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 to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. There have also been shortages of drilling rigs, hydraulic fracturing equipment and personnel and other oilfield equipment, as demand for rigs and equipment increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. These shortages or price increases could adversely affect the Company's profit margin, cash flow and operating results, or restrict its ability to drill wells and conduct ordinary operations.

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 in seeking to acquire desirable producing properties, seeking new properties for future exploration and seeking the 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.

Many of our competitors have financial and other resources substantially 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, effectively 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.

ITEM 1B UNRESOLVED STAFF COMMENTS

None

ITEM 2 PROPERTIES

At September 30, 2011, Panhandle's principal properties consisted of perpetual ownership of 255,857 net mineral acres, held principally in Arkansas, New Mexico, North Dakota, Oklahoma, Texas and six other states. The Company also held leases on 17,480 net acres primarily in Oklahoma. At September 30, 2011, Panhandle held working interests, royalty interest or both in 5,107 producing oil and natural gas wells and 48 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 properties 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 properties.

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

ACREAGE

Mineral Interests Owned

The following table of mineral interests 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, 2011.

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	11,111	47,650	5,743	20,534	1,785	5,433	3,583	21,683
Colorado	8,218	39,080			224	447	7,994	38,633
Florida	5,589	12,239					5,589	12,239
Kansas	3,082	11,816	144	1,200			2,938	10,616
Montana	1,008	17,947					1,008	17,947
New Mexico	57,375	174,300	1,352	7,125	525	760	55,498	166,415
North Dakota	11,178	64,286	114	956			11,064	63,330
Oklahoma	113,246	948,164	38,200	308,583	1,023	6,150	74,023	633,431
South Dakota	1,825	9,300					1,825	9,300
Texas	43,198	360,024	7,912	72,099	265	6,258	35,021	281,667
OTHER	27	262					27	262
Total:	**255,857**	**1,685,068**	**53,465**	**410,497**	**3,822**	**19,048**	**198,570**	**1,255,523**

(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.

State	Net Acres	Net Acres Expiring					Net Acres Held by Production
		2012	2013	2014	2015	2016	
Kansas	2,117						2,117
Oklahoma	13,403	195	530	654	10		12,014
Texas	504	3					501
Other	1,456			88			1,368
TOTAL	17,480	198	530	742	10	0	16,000

PROVED RESERVES

The following table summarizes estimates of proved reserves of oil and natural gas held by Panhandle. All proved reserves are located onshore within the United States and are principally made up of small interests in 5,107 wells, predominately all of which are located in the Mid-Continent region. Other than this report, the Company's reserve estimates are not filed with any other federal agency.

Net Proved Developed Reserves	Barrels of Oil	Barrels of NGL (1)	Mcf of Natural Gas	Mcfe
September 30, 2011	759,989	386,774	60,193,878	67,074,456
September 30, 2010	861,240	-	57,344,190	62,511,630
September 30, 2009	882,987	-	45,036,460	50,334,382
Net Proved Undeveloped Reserves				
September 30, 2011	83,749	404,874	41,644,106	44,575,844
September 30, 2010	63,769	-	40,826,265	41,208,879
September 30, 2009	37,886	-	8,991,350	9,218,666
Net Total Proved Reserves				
September 30, 2011	843,738	791,648	101,837,984	111,650,300
September 30, 2010	925,009	-	98,170,455	103,720,509
September 30, 2009	920,873	-	54,027,810	59,553,048

(1) 2011 is 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 Oklahoma, which includes many plays (horizontal Granite Wash, Hogshooter Wash, Cleveland, Marmaton, Tonkawa and the Anadarko Basin "Cana" Woodford Shale) producing significant volumes of NGL.

The 7.9 Bcfe increase in reserves is a combination of the following factors:

(1) Positive performance revisions of 9,681,460 Mcfe, which were principally attributable to properties in the southeast Oklahoma Woodford Shale and the Arkansas Fayetteville Shale. These revisions are principally the result of actual well performance on both new and existing wells exceeding the performance projections in the prior estimates. The improved performance in the new wells can be attributed to enhanced fracture stimulation and completion techniques and increased horizontal lateral lengths.

(2) Revisions related to the inclusion of natural gas liquids and the associated reduction in natural gas volumes due to the conversion of previously reported gas volumes into NGL volumes. The Company reported NGL reserves for the first time in the 2011 year-end report. Panhandle's increased drilling activity over the last 12-18 months in several western Oklahoma plays which produce significant NGL, have resulted in meaningful NGL production and reserves for the Company, necessitating inclusion in the reserve calculation.

(3) Negative gas pricing revisions of 8,911,784 Mcfe, which included revisions due to producing wells reaching their economic limits earlier than previously projected and revisions due to proved undeveloped locations, primarily in the southeast Oklahoma Woodford Shale, becoming uneconomic at current product prices.

(4) The Company's ongoing development of unconventional natural gas and natural gas liquids plays utilizing horizontal drilling, including the Anadarko Basin Woodford Shale.

(5) The Company's ongoing development of unconventional natural gas plays utilizing horizontal drilling, including the Arkansas Fayetteville Shale and the southeast Oklahoma Woodford Shale.

(6) The Company's ongoing development of conventional oil, natural gas liquids and natural gas plays

utilizing horizontal drilling, including the Granite Wash and Cleveland plays in western Oklahoma and the Texas Panhandle, as well as the Hogshooter Wash, Marmaton and Tonkawa plays in western Oklahoma.

The following details the changes in proved undeveloped reserves for 2011 (Mcfe):

Beginning proved undeveloped reserves	41,208,879
Proved undeveloped reserves transferred to proved developed	(5,190,555)
Revisions	995,953
Extensions and discoveries	4,744,630
Purchases	2,816,937
Ending proved undeveloped reserves	44,575,844

The beginning 2011 PUD reserves were 41,208,879 Mcfe. A total of 5,190,555 Mcfe (12.6% of the beginning balance) were transferred to proved developed during 2011. An additional 5,553,576 Mcfe (13.5% of the beginning balance) were removed during 2011 as the result of becoming uneconomic at 2011 product prices. A total of 10,744,131 Mcfe (26.1% of the beginning balance) of PUD reserves were moved out of the category during 2011 as the result of either being transferred to proved developed or removed as uneconomic. Only one PUD location from 2007 and one PUD location from 2008 remain in the PUD category. We anticipate that all the Company's remaining PUD locations will be drilled and converted to PDP within 5 years of the date they were added. However, 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, over time, regarding the development of individual reservoirs and as market conditions change, 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 includes 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 10 to the financial statements in Item 8 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 and natural gas reserves as of September 30, 2011 and 2010 (see Exhibits 23 and 99). Reserves as of September 30, 2009, were calculated by Pinnacle Energy

Services, L.L.C. of Oklahoma City, Oklahoma.

The Company's net proved oil and natural gas reserves (including certain undeveloped reserves described above), all of which are located onshore in the United States, as of September 30, 2011, 2010 and 2009, have been estimated by the Company's Independent Consulting Petroleum Engineering Firms. 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, 2011, 2010 and 2009. 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. Estimated future net cash flows as of September 30, 2009, have been computed by applying prices of oil and natural gas on September 30, 2009, to future production of proved reserves less estimated future expenditures to be incurred with respect to the development and production of these reserves. 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 as of September 30, 2010 and 2011, were computed using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month oil and natural gas price for each month within the 12-month period prior to September 30, 2010 and 2011, 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 pricing used for each of the three years presented complies with SEC regulations in effect for each year. The amounts presented are net of operating costs and production taxes levied by the respective states. The Company reported NGL reserves for the first time in the 2011 year-end report. Increased drilling activity over the last 12-18 months in several western Oklahoma plays which produce significant NGL, have resulted in meaningful NGL production and reserves for the Company, necessitating inclusion in the reserve calculation. Prices used for determining future cash flows from oil, natural gas liquids and natural gas as of September 30, 2011, were as follows: $90.28/Bbl, $38.91/Bbl, $3.81/Mcf, respectively. Prices used for determining future cash flows from oil and natural gas as of September 30, 2010 and 2009, were as follows: 2010 - $69.23/Bbl, $4.33/Mcf ; 2009 - $66.96/Bbl, $2.86/Mcf, respectively, (these natural gas prices are representative of local pipelines in Oklahoma). 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 and natural gas price and production cost increases or decreases, which could affect the economic life of the properties.

Estimated Future Net Cash Flows

	9-30-11	9-30-10	9-30-09
Proved Developed	$ 211,851,992	$ 202,056,455	$ 131,674,245
Proved Undeveloped	91,232,949	84,200,597	15,372,040
Income Tax Expense	107,111,317	99,118,090	43,832,666
Total Proved	$ 195,973,624	$ 187,138,962	$ 103,213,619

10% Discounted Present Value of Estimated Future Net Cash Flows

	9 30-11	9-30-10	9-30-09
Proved Developed	$ 106,464,138	$ 103,270,565	$ 73,869,512
Proved Undeveloped	29,977,891	21,960,347	6,800,080
Income Tax Expense	58,059,595	52,730,503	26,923,084
Total Proved	$ 78,382,434	$ 72,500,409	$ 53,746,508

OIL AND NATURAL GAS PRODUCTION

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

	Year Ended 9-30-11	Year Ended 9-30-10	Year Ended 9-30-09
Bbls - Oil	104,141	102,379	128,160
Mcf - Natural Gas	8,297,657	8,302,342	9,109,988
Mcfe	8,922,503	8,916,616	9,878,948

Natural gas production includes NGL volumes.

AVERAGE SALES PRICES AND PRODUCTION COSTS

The following table sets forth unit price and cost data for the fiscal periods indicated.

Average Sales Price	Year Ended 9-30-11	Year Ended 9-30-10	Year Ended 9-30-09
Per Bbl Oil	$ 88.00	$ 72.83	$ 51.79
Per Mcf, Natural Gas (1)	$ 4.13	$ 4.41	$ 3.38
Per Mcfe	$ 4.87	$ 4.94	$ 3.79

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

Average Production (lifting costs)	Year Ended 9-30-11	Year Ended 9-30-10	Year Ended 9-30-09
(Per Mcfe)			
Well Operating Costs (1)	$ 0.95	$ 0.92	$ 0.78
ProductionTaxes (2)	0.16	0.16	0.12
	$ 1.11	$ 1.08	$ 0.90

(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. The low production tax rate per Mcfe in 2009, 2010 and 2011 is because of a large proportion of the Company's natural gas revenue coming from horizontally drilled wells which are eligible for either Oklahoma production tax credits or reduced Arkansas production tax rates.

Approximately 34% of the Company's oil and natural gas revenue is generated from royalty payments 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, 2011. Panhandle owns either working interests, royalty interests or both in these wells. The Company does not operate any wells.

	Gross Wells	Net Wells
Oil	1,051	20.91
Natural Gas	4,056	93.91
Total	5,107	114.82

Information on multiple completions is not available from Panhandle's records, but the number is not believed to be significant.

As of September 30, 2011, Panhandle owned 410,497 gross developed mineral acres and 53,465 net developed mineral acres. Panhandle has also leased from others 137,284 gross developed acres containing 16,000 net developed acres.

UNDEVELOPED ACREAGE

As of September 30, 2011, Panhandle owned 1,255,523 gross and 198,570 net undeveloped mineral acres, and leases on 20,644 gross and 1,480 net 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.

Development Wells	Net Productive Wells	Net Dry Wells
Fiscal years ended:		
September 30, 2011	3.602221	0.062188
September 30, 2010	4.029693	0.057282
September 30, 2009	8.893170	0.092978
Exploratory Wells		
Fiscal years ended:		
September 30, 2011	0.783266	0.078125
September 30, 2010	0.160270	-- 0 --
September 30, 2009	0.867702	0.138051
Purchased Wells		
Fiscal years ended:		
September 30, 2011	0.235058	-- 0 --
September 30, 2010	-- 0 --	-- 0 --
September 30, 2009	-- 0 --	-- 0 --

PRESENT ACTIVITIES

The following table sets forth the gross and net oil and natural gas wells drilling or testing as of September 30, 2011, in which Panhandle owns either a working interest, a royalty interest or both. These wells were not producing at September 30, 2011.

	Gross Wells	Net Wells
Oil	16	0.54858
Natural Gas	32	0.67738

OTHER FACILITIES

The Company leases 12,369 square feet of office space in Oklahoma City, OK ending in 2012.

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 and natural gas; demand for oil and natural gas; estimates of proved oil and natural gas reserves; development and infill drilling potential; drilling prospects; business strategy; production of oil 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 2012 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 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 natural gas and crude oil are dependent on a number of factors beyond the Company's control, including: the demand for oil 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 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 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 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 and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil 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 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 and natural gas and estimates of the future net cash flows from oil and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, oil and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues and expenditures with respect to oil 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 and natural gas reserves attributable to the Company's properties. As required by the SEC, the 2010 and 2011 estimated discounted future net cash flows from proved oil and natural gas reserves are determined based on the fiscal year's 12-month average of the first-day-of-the-month oil and natural gas prices (oil and natural gas prices used for 2009 were based on the September 30 spot price of that year) 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 and natural gas production, supply and demand for oil 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, 2011, or at the date of this report.

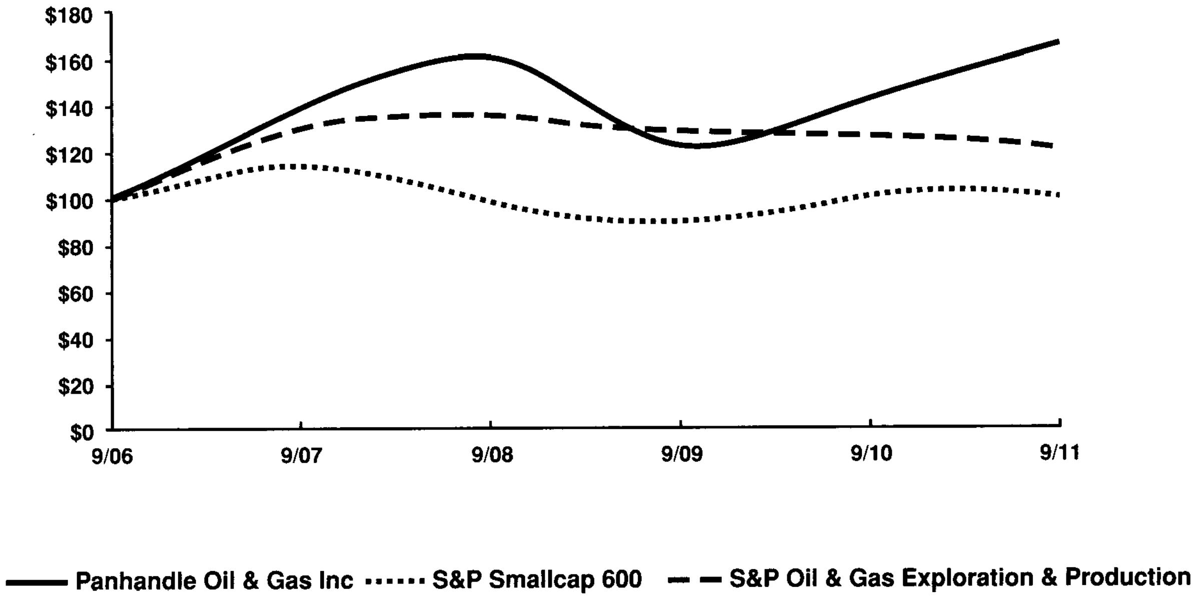
ITEM 4 SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of Panhandle's security holders during the fourth quarter of the fiscal year ended September 30, 2011.

PART II

ITEM 5 MARKET FOR COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND UNREGISTERED SALES 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 9/30/06 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, 2006, and its relative performance is tracked through September 30, 2011.

On July 22, 2008, the Company's Common Stock was listed on the New York Stock Exchange (symbol PHX) and, prior to that, it was listed on the American Stock Exchange under the same symbol. 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, 2009	$ 26.25	$ 19.06
March 31, 2010	$ 29.65	$ 20.34
June 30, 2010	$ 29.29	$ 21.97
September 30, 2010	$ 30.31	$ 21.00
December 31, 2010	$ 28.70	$ 23.75
March 31, 2011	$ 31.88	$ 25.60
June 30, 2011	$ 32.50	$ 27.30
September 30, 2011	$ 36.25	$ 26.36

At November 22, 2011, there were 1,592 holders of record of Panhandle's Class A Common Stock and approximately 4,200 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 of directors 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 of directors.

The Company's credit facility also contains a provision limiting the paying or declaring of a cash dividend to fifteen percent 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," 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 of directors 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 of directors' 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 of directors. 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 of directors determine otherwise. Pursuant to these resolutions adopted by the board of directors, the purchase of an additional $1.5 million of the Company's Common Stock became authorized and approved effective March 29, 2011. 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 2011. At September 30, 2011, and September 30, 2010, 10,710 and 11,632 (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 the "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,				
	2011	2010	2009	2008	2007
Revenues					
Oil and natural gas sales	$ 43,469,130	$ 44,068,947	$ 37,421,688	$ 69,026,785	$ 37,449,174
Lease bonuses and rentals	352,757	1,120,674	188,906	167,559	208,625
Gains (losses) on derivative contracts	734,299	6,343,661	(661,828)	(940,823)	765,316
Income from partnerships	420,465	405,134	323,848	631,891	383,391
	44,976,651	51,938,416	37,272,614	68,885,412	38,806,506
Costs and expenses					
Lease oper. exp. and prod. taxes	9,898,509	9,639,864	8,897,235	10,055,762	6,057,456
Exploration costs	1,025,542	1,583,773	711,582	455,943	1,050,069
Depr., depl. and amortization (DD&A)	14,712,188	19,222,123	28,168,933	19,784,660	15,291,625
Provision for impairment	1,728,162	605,615	2,464,520	526,380	3,761,832
Loss (gam) on asset sales, mt. & other	(68,325)	(1,028,148)	(2,677,407)	14,826	65,568
Gen. and administrative	5,994,663	5,594,499	4,866,044	5,006,512	3,877,492
Bad debt expense (recovery)	-	-	(185,272)	591,258	-
	33,290,739	35,617,726	42,245,635	36,435,341	30,104,042
Income (loss) before provision (benefit) for income taxes	11,685,912	16,320,690	(4,973,021)	32,450,071	8,702,464
Provision (benefit) for income taxes	3,192,000	4,901,000	(2,568,000)	10,894,302	2,359,000
Net income (loss)	$ 8,493,912	$ 11,419,690	$ (2,405,021)	$ 21,555,769	$ 6,343,464
Basic and diluted earnings (loss) per share	$ 1.01	$ 1.36	$ (0.29)	$ 2.54	$ 0.75
Dividends declared per share	$ 0.28	$ 0.28	$ 0.28	$ 0.28	$ 0.25
Weighted average shares outstanding Basic and diluted	8,393,890	8,422,387	8,397,337	8,492,378	8,499,233
Net cash provided by (used in):					
Operating activities	$ 29,283,929	$ 27,806,475	$ 37,710,606	$ 40,063,896	$ 28,106,500
Investing activities	$ (27,200,816)	$ (9,845,516)	$(36,322,992)	$ (37,846,172)	$ (26,940,679)
Financing activities	$ (4,173,372)	$ (13,003,609)	$ (1,643,414)	$ (2,311,376)	$ (610,814)
Total assets	$ 111,424,193	$105,124,839	$108,549,632	$122,007,183	$ 78,539,797
Long term debt	$ -	$ -	$ 10,384,722	$ 9,704,100	$ 4,661,471
Shareholders' equity	$ 78,802,317	$ 73,581,996	$ 64,122,343	$ 68,348,901	$ 53,681,371

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 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 and natural gas sales prices. Drilling activity increased during the last quarter of 2010 and continued at a much higher rate throughout 2011, as compared to the first nine months of fiscal 2010. This increase in drilling activity resulted in 2011 production volumes (on an Mcfe basis) that were relatively flat to those of 2010, thus reversing the decrease in production that occurred in 2010, as compared to 2009. The increased drilling activity is primarily on the Company's mineral acreage in the Arkansas Fayetteville Shale play and in the oil and natural gas liquids-rich plays such as the Anadarko (Cana) Woodford Shale, Horizontal Granite Wash, Hogshooter Wash, Cleveland, Marmaton, Tonkawa and other similar plays in western Oklahoma. As of September 30, 2011, the Company owned an average 2.6% net revenue interest in 48 wells that were drilling or testing. As these wells begin producing and other scheduled wells are drilled and completed in the abovementioned plays, we expect fiscal 2012 production to increase over that of 2011.

Further enhancing production in 2012 will be production from newly acquired producing properties during the last half of 2011 and the first quarter of 2012, primarily in the Arkansas Fayetteville Shale play. The producing properties included with these acquisitions will provide an immediate boost to our production, while the drilling and completion of a substantial number of wells on this newly acquired acreage is expected to provide additional production which will come on line later in 2012.

Although oil and natural gas production remained flat in 2011, oil and natural gas sales revenues decreased slightly as a result of lower natural gas prices, partially offset by increased oil prices. It is difficult to predict what oil and natural gas prices will be in 2012.

Oil, natural gas and natural gas liquids reserves increased in 2011 compared to 2010, the result of successful drilling of exploratory and developmental wells in excess of PUD reserves previously presented. The positive performance revisions recognized in the reserves reported at September 30, 2010, has resulted in lower 2011 DD&A.

Management currently expects drilling on the Company's acreage to result in capital expenditures for oil and natural gas activities of approximately $25 million during 2012. Also, during the first quarter of 2012, we closed the purchase of 1,531 net leasehold acres (82% of which is held by production) in the Fayetteville Shale at a cost of $17.5 million. The Company used existing cash and $13.3 million in borrowings from its bank credit facility to finance the acquisition. The acquisition included non-operating working interests in 193 producing gas wells and approximately 240 infill drilling locations. The Company will continue to evaluate opportunities to acquire mineral acreage or producing properties. Acquisitions, if any, will be financed by a combination of cash flows and the bank credit facility.

The Company had no off balance sheet arrangements during 2011 or prior years.

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

	For the Year Ended September 30,				
	2011	Percent Incr. or (Decr.)	2010	Percent Incr. or (Decr.)	2009
Production:					
Oil (Bbls)	104,141	2%	102,379	-20%	128,160
Natural Gas (Mcf)	8,297,657	0%	8,302,342	-9%	9,109,988
Mcfe	8,922,503	0%	8,916,616	-10%	9,878,948
Average Sales Price:					
Oil (per Bbl)	$ 88.00	21%	$ 72.83	41%	$ 51.79
Natural Gas (Mcf) (1)	$ 4.13	-6%	$ 4.41	30%	$ 3.38
Mcfe	$ 4.87	-1%	$ 4.94	30%	$ 3.79

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

RESULTS OF OPERATIONS

Fiscal Year 2011 Compared to Fiscal Year 2010

Overview

The Company recorded net income of $8,493,912, or $1.01 per share, in 2011, compared to net income of $11,419,690, or $1.36 per share, in 2010. Decreased revenues in 2011 were primarily due to lower realized and unrealized gains on derivative contracts and lower lease bonuses and rentals. Actual and forward looking prices were lower than the Company's derivative contracts during 2011, resulting in net gains on derivative contracts; however, the variation during 2011 was not as significant as in 2010, therefore, gains on derivative contracts during 2011 were significantly less. The renewal of leases on certain of the Company's Arkansas undeveloped mineral acreage generated significant lease bonuses during 2010; whereas there were no such renewals in 2011.

Expenses decreased due to lower DD&A and exploration costs in 2011, partially offset by increases in the provision for impairment, general and administrative costs and a decrease in gain on asset sales, interest and other. The positive performance revisions recognized in the reserves reported at September 30, 2010, has resulted in lower 2011 DD&A.

Oil and Natural Gas (And Associated Natural Gas Liquids) Sales

Oil and natural gas sales revenues decreased $599,817 or 1% for 2011, as compared to 2010. A decline in natural gas prices of 6% from 2010 to 2011, partially offset by a 21% increase in oil prices in 2011, caused the reduction of oil and natural gas sales revenues. Production from wells that came on line in 2011 offset the natural decline of existing wells such that oil and natural gas production volume in 2011 was relatively flat compared to 2010 volumes.

Drilling activity increased during the last quarter of 2010 and continued at a much higher rate throughout 2011, as compared to the first nine months of fiscal 2010. This increase in drilling activity resulted in 2011 production volumes (on an Mcfe basis) that were flat compared to those of 2010, thus reversing the decrease in production volumes that occurred in 2010, as compared to 2009. The increased drilling activity is primarily on the Company's mineral acreage in the Arkansas Fayetteville Shale and in the oil and natural gas liquids-rich plays such as the Anadarko (Cana) Woodford Shale, Horizontal Granite Wash, Hogshooter Wash, Cleveland, Marmaton, Tonkawa and other similar plays in western Oklahoma. As of September 30, 2011, the Company owned an average 2.6% net revenue interest in 48 wells that were drilling or testing.

Production by quarter for 2011 and 2010 was as follows:

	2011	2010
First quarter	2,208,218 Mcfe	2,278,133 Mcfe
Second quarter	2,152,011 Mcfe	2,090,154 Mcfe
Third quarter	2,129,160 Mcfe	2,236,236 Mcfe
Fourth quarter	2,433,114 Mcfe	2,312,093 Mcfe
Total	8,922,503 Mcfe	8,916,616 Mcfe

Lease Bonus and Rentals

Lease bonus and rentals decreased $767,917 for 2011, as compared to 2010. Lease bonus and rental revenues in 2010 included lease bonuses of approximately $723,000 from certain of the

Company's Arkansas mineral acreage, whereas there were no large leases of Company acreage in 2011.

Gains (Losses) on Derivative Contracts

Realized and unrealized gains and losses are scheduled below:

Gains (Losses) on Derivative Contracts	2011	2010
Realized	$ 2,138,685	$ 2,209,900
Unrealized	(1,404,386)	4,133,761
Total	$ 734,299	$ 6,343,661

The Company's natural gas fixed price swap contracts had expiration dates of October 2011; the oil costless collar contracts have expiration dates of December 2011; the natural gas basis protection swaps have expiration dates of December 2011 and December 2012.

Lease Operating Expenses (LOE) and Production Taxes

LOE increased $248,435 or 3% in 2011. LOE costs per Mcfe of production increased from $.92 in 2010 to $.95 in 2011. The total LOE increase and the LOE per Mcfe increase are primarily related to increased field operating costs of approximately $276,000 in 2011 compared to 2010. Field operating costs were $.44 per Mcfe in 2011 compared to $.41 per Mcfe in 2010, a 7% increase. These increases are principally the result of well workovers performed in 2011.

Value based fees (primarily gathering, transportation and marketing costs) on natural gas in 2011 were slightly less than those of 2010. These fees decreased LOE approximately $28,000 in 2011.

Production taxes increased $10,210 or 1% in 2011. Some wells previously eligible for production tax credits or reductions, primarily in Oklahoma and Arkansas, lost their eligibility during 2011 due to meeting either time or payout thresholds stipulated in Oklahoma and Arkansas production tax laws.

Exploration Costs

Exploration costs were $1,025,542 in 2011 compared to $1,583,773 in 2010, a $558,231 decrease. During 2011, leasehold impairment and expired leasehold totaled $482,491 compared to $1,191,598 during 2010, a $709,107 decrease. The decline was driven by lower provisions for expected lease expirations in 2011, as compared to 2010. Charges on two exploratory dry holes totaled $543,051 during 2011; whereas, in 2010 the Company incurred minor exploratory dry hole costs totaling $4,541. During 2010, $387,634 was charged to exploration costs related to geological and geophysical costs paid upon the execution of a joint exploration agreement with a privately held independent operator to explore for oil in eastern Oklahoma.

Depreciation, Depletion and Amortization (DD&A)

Total DD&A decreased $4,509,935 or 24% in 2011, while DD&A per Mcfe decreased to $1.65 in 2011, as compared to $2.16 in 2010. The DD&A decrease is attributable to the $.51 decline in the DD&A rate per Mcfe. This rate decline in 2011 was due to the positive performance revisions recognized in the reserves reported at September 30, 2010.

Provision for Impairment

The provision for impairment increased $1,122,547 in 2011, as compared to 2010. During 2011, impairment of $1,728,162 was recorded on nine 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 little production history is added to one of these fields. On one of these fields, a new material well began production on September 27, 2011. The well's early production was significantly impacted by the recovery of large volumes of water utilized in the fracture treatment. Since the well's early production has been low, while at the same time producing large volumes of load water, the calculated reserves and future net cash flows were calculated to be significantly less than was previously attributed to the well, resulting in a material impairment to the field, which was impaired in total by $590,629. Wells such as this are subject to performance revisions going forward as more is known of their production history and pattern. During the 2010 period, impairment of $605,615 was recorded on six small fields.

Included in the 2011 total above, is an impairment charge of $716,448 on the Joiner City prospect, a horizontal Woodford Shale prospect in the oil and natural gas liquids-rich Marietta Basin in southern Oklahoma. The first well was drilled and completed during the first quarter of 2011 and is currently producing commercial quantities of oil and natural gas. Production volumes and future development potential are being evaluated. As of September 30, 2011, this well had a net book value of $503,960 after impairment. Costs on this well were extraordinarily high due to this well being the first and only horizontal well drilled in the field.

Loss (Gain) on Asset Sales, Interest and Other

In 2010, the Company received $1,124,682 from the settlement of a lawsuit related to one well in western Oklahoma. No interest expense was incurred during 2011, compared to interest expense of $60,912 recorded in 2010.

General and Administrative Costs (G&A)

G&A increased $400,164 or 7% in 2011. The increase is primarily related to increases in the following expense categories: personnel $346,331; board of directors fees $92,674; computer consulting fees $20,000; and reservoir engineering fees $71,000. The above were partially offset by a decrease in legal fees of $228,837 in 2011. The increase in 2011 personnel related expenses was the result of annual increases in salaries and bonuses totaling approximately $113,000, a restricted stock expense increase of $140,454, a rise in employee insurance costs of $22,713 and higher ESOP expense by $20,220. The increase in board of directors fees resulted from the addition of one director in May 2010 (resulting in partial year retainer and meeting fees during 2010, but a full year's fees during 2011) combined with increases in annual retainer fees and meeting fees paid to directors during 2011.

Non-recurring legal fees of approximately $230,000 were expensed during 2010 related to a lawsuit on one well in western Oklahoma and to the 2008 bankruptcy of SemGroup, L.P., which owed the Company for crude oil they had purchased.

Provision (Benefit) for Income Taxes

The 2011 provision for income taxes of $3,192,000 was based on a pre-tax income of $11,685,912, as compared to a provision for income taxes of $4,901,000 in 2010, based on a pre-tax income of $16,320,690. Income taxes in 2010 were reduced by the removal of the $278,000 valuation allowance on Oklahoma NOLs which reduced the effective tax rate by 2%. The effective tax rate for 2011 was 27%, compared to an effective tax rate for 2010 of 30%. 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.

Fiscal Year 2010 Compared to Fiscal Year 2009

Overview

The Company recorded net income of $11,419,690, or $1.36 per share, in 2010 compared to net loss of $2,405,021, or $.29 per share, in 2009. Increased revenues in 2010 were mainly from increases in oil and natural gas sales, gains on derivative contracts and lease bonuses. Higher oil and natural gas prices more than offset a 10% decrease in production resulting in increased oil and natural gas sales; actual and forward looking prices lower than the Company's fixed price swap contracts resulted in gains on derivative contracts in 2010 compared to a loss in 2009; and the renewal of leases on certain of the Company's Arkansas undeveloped mineral acreage increased 2010 revenue from lease bonuses.

The decrease in expenses was primarily related to lower DD&A and impairment costs, resulting from the increase in oil and natural gas reserves (as of September 30, 2010) which lowered the DD&A rate per Mcfe of production. In 2010, an income tax expense of $4,901,000 was incurred compared to a tax benefit of $2,568,000 recognized in 2009.

Oil and Natural Gas (And Associated Natural Gas Liquids) Sales

Oil and natural gas sales increased $6,647,259 or 18% for 2010, as compared to 2009. Driven by higher oil and natural gas prices of 41% and 30%, respectively, 2010 oil and natural gas sales went up, despite a 10% decrease in combined oil and natural gas production on an Mcfe basis. The production decrease occurred as fewer new wells were drilled and put on line in 2010, thus the production decline of existing wells exceeded the production which came on line from new wells.

Production by quarter for 2010 and 2009 was as follows:

	2010	2009
First quarter	2,278,133 Mcfe	2,495,299 Mcfe
Second quarter	2,090,154 Mcfe	2,380,124 Mcfe
Third quarter	2,236,236 Mcfe	2,647,474 Mcfe
Fourth quarter	2,312,093 Mcfe	2,356,051 Mcfe
Total	8,916,616 Mcfe	9,878,948 Mcfe

Lease Bonus and Rentals

Lease bonus and rentals increased $931,768 for 2010, as compared to 2009. This increase was principally due to the renewal of leases on certain of the Company's Arkansas undeveloped mineral acreage which increased 2010 revenue from lease bonuses approximately $723,000.

Gains (Losses) on Natural Gas Derivative Contracts

Realized and unrealized gains and losses are scheduled below:

Gains (losses) on derivative contracts	2010	2009
Realized	$ 2,209,900	$ 2,497,800
Unrealized	4,133,761	(3,159,628)
Total	$ 6,343,661	$ (661,828)

Lease Operating Expenses (LOE) and Production Taxes

LOE increased $497,293 or 7% in 2010. LOE costs per Mcfe of production increased from $.78 in 2009 to $.92 in 2010. Increased natural gas prices, which increased value based fees (primarily gathering, transportation and marketing costs) caused total LOE and LOE per Mcfe to increase. Natural gas production from the southeast Oklahoma Woodford Shale, Anadarko (Cana) Woodford Shale and Fayetteville Shale areas continued to increase as a proportion of total production. Value based fees are charged as a percent of natural gas revenues and are significantly higher in these shale areas than like fees charged in other of the Company's production areas. The total amount of value based fees in these three shale areas typically are 12% to 22% of total natural gas revenues. Value based fees increased $1,201,209, or 36%, in 2010 compared to 2009. Value based fees per Mcfe increased $.17, or 51%, in 2010 compared to 2009.

The increase in value based fees was partially offset by a decrease of $703,916 in LOE related to field operating costs in 2010 compared to 2009, a 16% decrease. In 2010, field operating costs were $.38 per Mcfe compared to $.42 per Mcfe in 2009, a 9% decrease. These decreases were due to fewer wells coming on line in 2010 with high initial LOE, fewer well repairs made in 2010 compared to 2009 and the fiscal 2009 sale of wells in the Southeast Leedey field and the McElmo Dome Unit, thus reducing fiscal 2010 LOE.

Production taxes increased $245,336, or 20%, in 2010. The increase was the result of increased sales of oil and natural gas. Oil and natural gas sales in 2010 increased 18%, and production taxes increased 20% compared to 2009. Production taxes were 3.3% of oil and natural gas sales in 2010, compared to 3.2% in 2009. The low overall production tax rate was due to a large proportion of the Company's natural gas revenues coming from horizontally drilled wells, which were eligible for either Oklahoma production tax credits or reduced Arkansas production tax rates.

Exploration Costs

Exploration costs were $1,583,773 in 2010 compared to $711,582 in 2009, an $872,191 increase. During 2010, leasehold impairment and expired leases totaled $1,191,598 compared to $634,918 during 2009, a $556,680 increase. Five exploratory dry holes incurred expenses of approximately $77,000 during 2009; one exploratory dry hole incurred expenses of approximately $5,000 during 2010.

Also, the Company charged approximately $387,000 to exploration costs in 2010 related to geological and geophysical costs paid upon the execution of a joint exploration agreement with a privately held independent operator to explore for oil in eastern Oklahoma.

Depreciation, Depletion and Amortization (DD&A)

Total DD&A decreased $8,946,810, or 32%, in 2010, while DD&A per Mcfe decreased to $2.16 in 2010, as compared to $2.85 in 2009. Approximately $2,744,000 of the DD&A decrease was the result of a 10% decrease in 2010 combined oil and natural gas production on an Mcfe basis. The remaining DD&A decrease of approximately $6,203,000 was attributable to the $.69 decline in the DD&A rate per Mcfe. This rate declined as a result of increased proved developed oil and natural gas reserves as of

September 30, 2010 (see Financial Statements, Note 10 – Supplementary Information on Oil and Natural Gas Reserves), as compared to September 30, 2009, and a net reduction during fiscal year 2009 of approximately $3.1 million of asset basis subject to DD&A. This asset basis reduction occurred as fiscal 2009 DD&A and impairment, combined with the basis reduction associated with assets sold, exceeded new additions to properties and equipment for oil and natural gas activities.

Provision for Impairment

The provision for impairment decreased $1,858,905 in 2010, as compared to 2009. During 2010, impairment of $605,615 was recorded on six fields. Approximately $380,000 of the impairment was related to the Buffalo Wallow field in Texas, where the first horizontal well in the field was recently drilled and completed with poor economic results. During 2009, impairment of $2,464,520 was recorded on 13 fields driven by depressed oil and natural gas prices, which negatively affected the estimates of future net revenues from oil and natural gas properties.

Loss (Gain) on Asset Sales, Interest and Other

In 2010, the Company received $1,124,682 from the settlement of a lawsuit related to one well in western Oklahoma. In 2009, the Company sold a portion of its working interest in the Southeast Leedey field and all of its working interest in the McElmo Dome CO2 Unit for a combined gain of approximately $2.5 million.

General and Administrative Costs (G&A)

G&A increased $728,455, or 15%, in 2010 due to increases in the following expense categories: salaries, bonuses and benefits $433,847; legal $161,016; board of directors fees $101,474; and insurance $87,350. Personnel expenses increased mainly because of higher accrued performance bonuses based on improved Company performance metrics in fiscal 2010 compared to 2009. Legal expense increased primarily due to legal costs of approximately $129,000 incurred during 2010 on a lawsuit related to one well in western Oklahoma. The addition of a new director, an increase in the number of Board meetings and increased director fees resulted in the increase in board of directors' expense in 2010.

Bad Debt Expense (Recovery)

On July 22, 2008, SemGroup, L.P. and certain subsidiaries (SemGroup) filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy code. On October 28, 2009, the U.S. Bankruptcy Court confirmed the Fourth Amended Joint Plan of Affiliated Debtors which set forth various settlement details for producers and interest owners. Based on the details of the plan, discussion with operators impacted and management's judgment, the Company lowered the reserve for doubtful accounts to $405,129 at September 30, 2009, resulting in $186,129 of bad debt recovery. No adjustments were made in 2010 to the Company's reserve for doubtful accounts.

Provision (Benefit) for Income Taxes

The 2010 provision for income taxes was $4,901,000 based on a pre-tax income of $16,320,690, as compared to a benefit for income taxes of $2,568,000 in 2009, based on a pre-tax loss of $4,973,021. The provision for income taxes increased in 2010 by $7,469,000, the result of a $21,293,711 increase in income (loss) before provision (benefit) for income taxes in 2010, compared to 2009, partially offset by the removal of the $278,000 valuation allowance on Oklahoma NOLs. The effective tax rate for 2010 was 30%, whereas the effective tax benefit rate for 2009 was 52%. The Company's utilization of excess percentage depletion (which is a permanent tax benefit) decreased the provision for income taxes in 2010, whereas it increased the tax benefit in 2009. The effect of this permanent tax benefit is that the effective tax rate is decreased when recording a provision for income taxes as in 2010, while increasing the effective tax rate when recording a benefit for income taxes as in 2009. 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. The reversal of the $278,000 valuation allowance on Oklahoma NOLs reduced the effective tax rate by 2% for 2010.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2011, the Company had positive working capital of $7,314,096, as compared to positive working capital of $10,098,861 at September 30, 2010.

Liquidity

Cash and cash equivalents were $3,506,999 as of September 30, 2011, compared to $5,597,258 at September 30, 2010, a decrease of $2,090,259. Cash flows for the 12 months ended September 30 are summarized as follows:

Net cash provided (used) by:

	2011	2010	Change
Operating activities	$ 29,283,929	$ 27,806,475	$ 1,477,454
Investing activities	$ (27,200,816)	$ (9,845,516)	$ (17,355,300)
Financing activities	$ (4,173,372)	$ (13,003,609)	$ 8,830,237
Increase (decrease) in cash and cash equivalents	$ (2,090,259)	$ 4,957,350	$ (7,047,609)

Operating activities:

The increase of $1,477,454 in cash provided by operating activities is primarily the effect of the following:

Increased collections of oil and natural gas sales (net of withheld production taxes and value based fees) for the 2011 period compared to the 2010 period resulted in additional cash provided by operating activities of approximately $985,000.

Income tax payments in 2011 were $2,584,172 compared to payments of $3,530,718 in 2010, a decrease of $946,546.

Cash expenditures for lease operating expenses (other than value based fees) increased approximately $206,000 in 2011 compared to 2010.

Investing activities:

Investing activities were comprised of capital expenditures of $27,545,348 and $11,308,506 for 2011 and 2010, respectively. Capital expenditure increases of $16,236,842 resulted from increased drilling activity in several areas which are discussed in more detail below, combined with mineral and working interest acquisitions totaling approximately $4.8 million.

Financing activities:

The Company completely paid off the outstanding balance of $10.4 million on its credit facility in 2010, and the credit facility was not utilized during 2011. Approximately $2.3 million in dividends were paid during both 2010 and 2011. Also, Common Stock purchases in the amount of $1,851,290 were made in 2011, as compared to $291,383 in 2010.

Capital Resources

An increase of $16,236,842 in capital expenditures in 2011, as compared to 2010, was primarily the result of a continuing increase in drilling activity in western Oklahoma where we own substantial mineral, and to a lesser extent, leasehold acreage in oil and natural gas liquids-rich areas (Anadarko (Cana) Woodford Shale, Horizontal Granite Wash, Hogshooter Wash, Cleveland, Marmaton, Tonkawa and other similar plays in Western Oklahoma). In addition, there continued to be steady drilling activity in the Arkansas Fayetteville Shale area. During the last half of 2011 we acquired 1,235 producing mineral acres, 231 non-producing mineral acres and 88 non-producing leasehold acres primarily in the Arkansas Fayetteville Shale at a combined cost of approximately $4.8 million.

During the first quarter of fiscal 2012, the Company purchased 1,531 net leasehold acres which included small working interests in 193 producing wells and 240 future drilling locations in the Fayetteville Shale at a cost of $17.5 million. The Company utilized cash and borrowings of $13.3 million from its bank credit facility to finance the acquisition. We will continue to evaluate other acquisition opportunities in the future and expect to fund any acquisitions from either cash or the bank credit facility. The producing properties included with these acquisitions will provide an immediate increase in production, while the drilling and completion of additional wells on this newly acquired acreage during 2012 is expected to provide additional production coming on line later in 2012 and future years.

Production for 2011 was relatively flat to 2010 levels. Though we experienced an increase in drilling activity in 2011 in the areas discussed above, the increase was slower materializing than anticipated. New production coming on line during 2011 was roughly equal to the decline of existing wells' production. As the 48 wells that are currently completing or drilling come on line, this new production combined with the added production from the newly acquired properties will increase the Company's production level in 2012.

It is important to note that, as the Company is not the operator of any of its oil and natural gas properties, it is extremely difficult for us to predict our future capital expenditures levels and expected production additions.

With the recent decline in natural gas prices and the high levels of natural gas in storage, combined with steady domestic drilling, it is impossible to accurately predict natural gas price levels for 2012. Our natural gas fixed swap contracts expired in October 2011, our costless collar contracts on 5,000 barrels per month of our crude oil production will expire in December 2011 and our natural gas basis protection swap contracts will expire in December 2011 and December 2012. During this highly volatile period for oil and natural gas prices, management continues to evaluate opportunities and timing for product price protection by hedging a portion of the Company's future oil and natural gas production.

For 2011, cash provided by operating activities exceeded capital expenditures by $1,738,581. After payment of our regular $.07 per share quarterly dividends totaling $2,322,082, making Common

Stock purchases of $1,851,290 and other miscellaneous investing activities, cash was reduced during 2011 by $2,090,259. Looking forward, the Company expects to fund overhead costs, capital additions, Common Stock purchases and dividend payments primarily from cash flow and cash on hand. During the first quarter of 2012, the Company utilized its excess cash and bank credit facility to finance the $17.5 million purchase of Fayetteville Shale assets discussed above. As management evaluates other opportunities to acquire additional assets, borrowings utilizing our bank credit facility could be necessary. Also, during times of oil and natural gas price decreases, or increased expenditures for drilling, it may be necessary for the Company to utilize its credit facility further in order to fund these expenditures. The Company has availability ($35 million at September 30, 2011, $21.7 million after the Fayetteville Shale acquisition) under its revolving credit facility. The Company is in compliance with its debt covenants (current ratio, debt to EBITDA, tangible net worth 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 flows for 2012, the Company has sufficient liquidity to fund its ongoing operations and, combined with availability under its credit facility, to fund any acquisitions.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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 which is subject to a semi-annual borrowing base determination. The current borrowing base is $35,000,000. The revolving loan matures on November 30, 2014. Borrowings under the revolving loan are due at maturity. The revolving loan bears interest at the national prime rate plus a range of .50% to 1.25%, or 30 day LIBOR plus a range of 2.00% to 2.75% annually. 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 or whenever BOK believes there has been a material change in the value of the Company's oil and natural gas properties. 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, 2011, the Company was in compliance with these covenants.

The table below summarizes the Company's contractual obligations and commitments as of September 30, 2011:

Contractual Obligations and Commitments	Payments due by period: Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$ -	$ -	$ -	$ -	$ -
Building lease	$ 119,052	$ 119,052	$ -	$ -	$ -

At September 30, 2011, the Company's derivative contracts were in a net asset position of $215,940. 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 of Notes to Financial Statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding the derivative contracts.

As of September 30, 2011, the Company's asset retirement obligations were $1,843,875. 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 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 of Notes to 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 and natural gas reserve estimation, derivative contracts, impairment of assets, oil 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 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 and natural gas revenue accrual to be subject to future change.

Oil and Natural Gas Reserves

Management considers the estimation of the Company's crude oil 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, as well as DD&A and impairment calculations. Changes in crude oil and natural gas reserve estimates affect the Company's calculation of DD&A, provision for abandonment 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 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 current with the period. 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 oil and natural gas reserves at September 30, 2010 and 2011, were computed using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month oil and natural gas price for each month within the 12-month period prior to September 30, 2010 and 2011, held flat over the life of the properties. In accordance with SEC rules effective in fiscal year 2009, current pricing of oil and natural gas on September 30, 2009, held flat over the life of the properties was used to estimate oil and natural gas reserves as of September 30, 2009. Based on the Company's 2011 DD&A, a 10% change in the DD&A rate per Mcfe would result in a corresponding $1,471,219 annual change in DD&A expense. Crude oil, natural gas and NGL prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. However, projected future crude oil, natural gas and NGL pricing assumptions are used by management to prepare estimates of crude oil, natural gas and NGL 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 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 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 significantly 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 entered into oil costless collar contracts, 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 currently). 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 unsecured.

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. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines, changes in fair value are recognized in other comprehensive income (loss) until the hedged item is recognized in earnings. Hedge effectiveness is required to be measured at least quarterly, based on relative changes in fair value between the derivative contract and hedged item during the period of hedge designation. The ineffective portion of a derivative's change in fair value is recognized in current earnings. For derivative instruments not designated as hedging instruments, the change in fair value is recognized in earnings during the period of change as a change in derivative fair value. At September 30, 2011, the Company had no derivative contracts designated as cash flow hedges.

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, natural gas and NGL, future production costs, estimates of future oil, natural gas and NGL reserves to be recovered and the timing thereof, the 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, natural gas and NGL and a discount rate in line with the discount rate we believe is most commonly used by the market participants (currently 10%). The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to oil, natural gas and NGL reserves. A significant reduction in oil 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, 2011, the remaining carrying cost of non-producing oil and natural gas leases was $580,893.

Oil and Natural Gas Sales Revenue Accrual

The Company does not operate its oil and natural gas properties and, therefore, receives actual oil 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 many of these wells, the most current available production data is gathered from the appropriate operators, and oil 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 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 and natural gas. These variables could lead to an over or under accrual of oil 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, a high-level estimate is made taking into account historical data and current pricing. The Company has certain state net operating loss carryforwards (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 completed in a manner which encounters and subsequently produces from a geological formation at an angle in excess of seventy (70) degrees from the vertical and which laterally penetrates a minimum of one hundred and fifty (150) 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 (OTC) 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 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 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 OTC 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.

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 and natural gas prices historically have been volatile, and this volatility is expected to continue. Uncertainty continues to exist as to the direction of natural gas and oil 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 natural gas liquids 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 natural gas, oil and natural gas liquids in 2012 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 2012 natural gas derivative contracts (see below), based on the Company's estimated natural gas volumes for 2012, the price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $1,005,000 for operating revenue. Based on the Company's estimated oil volumes for 2012, the price sensitivity in 2012 for each $1.00 per barrel change in wellhead oil is approximately $112,000 for operating revenue.

Commodity Price Risk

The Company periodically utilizes derivative contracts to reduce its exposure to unfavorable changes in oil and natural gas prices. The Company does not enter into these derivatives for speculative or trading purposes. As of September 30, 2011, the Company has oil costless collars, natural gas fixed swap contracts and natural gas basis protection swaps (Refer to the "Derivatives" section of Note 1 for more detail) in place. All of our outstanding derivative contracts are with one counterparty and are unsecured. These arrangements cover only a portion of the Company's production and provide only partial price protection against declines in natural gas 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 as of September 30, 2011, the sensitivity of a $0.10 per Mcf change in the indexed pipelines (CEGT and PEPL) futures price is approximately $35,000 for pre-tax operating income. For the Company's natural gas basis protection swaps as of September 30, 2011, the sensitivity of a $.10 per MCF change in differential between NYMEX and the indexed pipelines (CEGT and PEPL) futures prices is approximately $304,000 for pre-tax operating income. For the Company's oil collars, a change of $1.00 in the forward strip prices would result in a change to pre-tax operating income of approximately $18,000.

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 national prime rate plus from .50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%. At September 30, 2011, the Company had no balance 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, 2011. 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, 2011, 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, 2011, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2011, 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, 2011 and 2010, and the related statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2011 and our report dated December 8, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 8, 2011

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, 2011 and 2010, and the related statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2011. 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, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2011, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the financial statements, in 2010 Panhandle Oil and Gas Inc. changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2011, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated December 8, 2011, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 8, 2011

Panhandle Oil and Gas Inc.
Balance Sheets

	September 30, 2011	September 30, 2010
Assets		
Current Assets:		
Cash and cash equivalents	$ 3,506,999	$ 5,597,258
Oil and natural gas sales receivables, net of allowance for uncollectible accounts	8,811,404	9,063,002
Refundable income taxes	354,246	-
Refundable production taxes	223,672	804,120
Derivative contracts	269,329	1,481,527
Other	95,408	412,778
Total current assets	13,261,058	17,358,685
Properties and equipment at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	230,554,198	207,928,578
Non-producing oil and natural gas properties	11,100,350	9,616,330
Furniture and fixtures	628,929	656,889
	242,283,477	218,201,797
Less accumulated depreciation, depletion and amortization	146,147,514	131,983,249
Net properties and equipment	96,135,963	86,218,548
Investments	667,504	754,208
Derivative contracts	-	138,799
Refundable production taxes	1,359,668	654,599
Total assets	$ 111,424,193	$ 105,124,839

(Continued on next page)

See accompanying notes.

Panhandle Oil and Gas Inc.
Balance Sheets

	September 30, 2011	September 30, 2010
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts payable	$ 4,899,593	$ 5,062,806
Deferred income taxes	7,100	354,100
Accrued liabilities and other	1,040,269	1,842,918
Total current liabilities	5,946,962	7,259,824
Deferred income taxes	24,777,650	22,552,650
Asset retirement obligations	1,843,875	1,730,369
Derivative contracts	53,389	-
Stockholders' equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized, 8,431,502 issued at September 30, 2011 and 2010	140,524	140,524
Capital in excess of par value	1,924,507	1,816,365
Deferred directors' compensation	2,665,583	2,222,127
Retained earnings	79,771,563	73,599,733
	84,502,177	77,778,749
Treasury stock, at cost; 175,331 shares at September 30, 2011, and 120,560 shares at September 30, 2010	(5,699,860)	(4,196,753)
Total stockholders' equity	78,802,317	73,581,996
Total liabilities and stockholders' equity	$ 111,424,193	$ 105,124,839

See accompanying notes.

Panhandle Oil and Gas Inc.
Statements of Operations

	Year ended September 30,		
	2011	2010	2009
Revenues:			
Oil and natural gas (and associated natural gas liquids) sales	$ 43,469,130	$ 44,068,947	$ 37,421,688
Lease bonuses and rentals	352,757	1,120,674	188,906
Gains (losses) on derivative contracts	734,299	6,343,661	(661,828)
Income from partnerships	420,465	405,134	323,848
	44,976,651	51,938,416	37,272,614
Costs and expenses:			
Lease operating expenses and production taxes	9,898,509	9,639,864	8,897,235
Exploration costs	1,025,542	1,583,773	711,582
Depreciation, depletion and amortization	14,712,188	19,222,123	28,168,933
Provision for impairment	1,728,162	605,615	2,464,520
Loss (gain) on asset sales, interest and other	(68,325)	(1,028,148)	(2,677,407)
General and administrative	5,994,663	5,594,499	4,866,044
Bad debt expense (recovery)	-	-	(185,272)
	33,290,739	35,617,726	42,245,635
Income (loss) before provision (benefit) for income taxes	11,685,912	16,320,690	(4,973,021)
Provision (benefit) for income taxes	3,192,000	4,901,000	(2,568,000)
Net income (loss)	$ 8,493,912	$ 11,419,690	$ (2,405,021)
Basic and diluted earnings per common share:			
Net income (loss)	$ 1.01	$ 1.36	$ (0.29)

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, 2008	8,431,502	$ 140,524	$ 2,090,070	$ 1,605,811	$ 69,236,604	(131,374)	$ (4,724,108)	$ 68,348,901
Issuance of treasury shares to ESOP	-	-	(165,017)	-	-	11,508	413,828	245,811
Common shares to be issued to directors for services	-	-	-	256,688	-	-	-	256,688
Dividends declared ($.28 per share)	-	-	-	-	(2,324,036)	-	-	(2,324,036)
Net loss	-	-	-	-	(2,405,021)	-	-	(2,405,021)
Balances at September 30, 2009	8,431,502	$ 140,524	$ 1,922,053	$ 1,862,499	$ 64,507,547	(119,866)	$ (4,310,280)	$ 64,122,343
Purchase of treasury stock	-	-	-	-	-	(12,326)	(291,383)	(291,383)
Issuance of treasury shares to ESOP	-	-	(117,716)	-	-	11,632	404,910	287,194
Restricted stock awards	-	-	12,028	-	-	-	-	12,028
Common shares to be issued to directors for services	-	-	-	359,628	-	-	-	359,628
Dividends declared ($.28 per share)	-	-	-	-	(2,327,504)	-	-	(2,327,504)
Net income	-	-	-	-	11,419,690	-	-	11,419,690
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

See accompanying notes.

Panhandle Oil and Gas Inc.
Statements of Cash Flows

	Year ended September 30,		
	2011	2010	2009
Operating Activities			
Net income (loss)	$ 8,493,912	$ 11,419,690	$ (2,405,021)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	14,712,188	19,222,123	28,168,933
Impairment	1,728,162	605,615	2,464,520
Provision for deferred income taxes	1,878,000	777,000	(3,814,000)
Exploration costs	1,025,542	1,208,653	711,582
Net (gain) loss on sales of assets	(350,530)	(1,189,605)	(2,654,759)
Income from partnerships	(420,465)	(405,134)	(323,848)
Distributions received from partnerships	553,382	523,317	432,805
Other	-	64,555	4,708
Common stock contributed to ESOP	303,843	287,194	245,811
Common stock (unissued) to Directors' Deferred Compensation Plan	443,456	359,628	256,688
Restricted stock awards	152,482	12,028	-
Bad debt expense (recovery)	-	-	(185,272)
Cash provided (used) by changes in assets and liabilities:			
Oil and natural gas sales receivables	251,598	(1,315,445)	9,620,843
Fair value of derivative contracts	1,404,386	(4,133,761)	3,159,628
Refundable income taxes	(354,246)	-	2,162,305
Refundable production taxes	(124,621)	(69,874)	(921,769)
Other current assets	317,370	(343,961)	74,455
Accounts payable	72,119	(24,896)	287,883
Income taxes payable	(922,136)	583,625	338,511
Accrued liabilities	119,487	225,723	86,603
Total adjustments	20,790,017	16,386,785	40,115,627
Net cash provided by operating activities	29,283,929	27,806,475	37,710,606
Investing Activities			
Capital expenditures, including dry hole costs	(27,545,348)	(11,308,506)	(39,915,051)
Proceeds from leasing of fee mineral acreage	389,807	1,316,377	209,930
Investments in partnerships	(46,213)	(254,555)	(59,742)
Proceeds from sales of assets	938	401,168	3,441,871
Net cash used in investing activities	(27,200,816)	(9,845,516)	(36,322,992)

(Continued on next page)

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

	Year ended September 30,		
	2011	2010	2009
Financing Activities			
Borrowings under debt agreement	$ -	$ 10,799,814	$ 49,027,225
Payments of loan principal	-	(21,184,536)	(48,346,603)
Purchases of treasury stock	(1,851,290)	(291,383)	-
Payments of dividends	(2,322,082)	(2,327,504)	(2,324,036)
Net cash used in financing activities	(4,173,372)	(13,003,609)	(1,643,414)
Increase (decrease) in cash and cash equivalents	(2,090,259)	4,957,350	(255,800)
Cash and cash equivalents at beginning of year	5,597,258	639,908	895,708
Cash and cash equivalents at end of year	$ 3,506,999	$ 5,597,258	$ 639,908
Supplemental Disclosures of Cash Flow Information			
Interest paid (net of capitalized interest)	$ -	$ 60,912	$ -
Income taxes paid, net of refunds received	$ 2,584,172	$ 3,530,718	$ (1,261,808)
Supplemental schedule of noncash investing and financing activities:			
Additions and revisions, net, to asset retirement obligations	$ 113,506	$ 110,144	$ 95,076
Gross additions to properties and equipment	$ 27,310,016	$ 11,585,521	$ 28,540,290
Net (increase) decrease in accounts payable for properties and equipment additions	235,332	(277,015)	11,374,761
Capital expenditures, including dry hole costs	$ 27,545,348	$ 11,308,506	$ 39,915,051

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 and natural gas production is from interests in 5,107 wells located principally in Oklahoma. Approximately 79% of oil and natural gas revenues are derived from the sale of natural gas. Substantially all the Company's oil 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 as a 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, natural gas and natural gas liquids reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as depreciation, depletion and amortization (DD&A) and impairment calculations. On an annual basis, with a limited scope semi-annual update, the Company's Independent Consulting Petroleum Engineer, with assistance from the Company, prepares estimates of crude oil, natural gas and natural gas liquids 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 2010 and 2011 reserve estimates were based on average individual product prices during the 12-month period prior to September 30, 2010 and 2011, 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. Oil and natural gas prices used for the 2009 estimate were based on the September 30 price of that year. For impairment purposes, projected future crude oil, natural gas and natural gas liquids prices as estimated by management are used. Crude oil, natural gas and natural gas liquids prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Projected future crude oil, natural gas and natural gas liquids pricing assumptions are used by management to prepare estimates of crude oil, natural gas and natural gas liquids reserves used in formulating management's overall operating decisions.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The Company does not operate its oil and natural gas properties and, therefore, receives actual oil 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 many of these wells, the most current available production data is gathered from the appropriate operators, and oil 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 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 and natural gas. These variables could lead to an over or under accrual of oil 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 and Natural Gas (and associated natural gas liquids) Sales and Natural Gas Imbalances

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

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 reservoir cannot be recouped through the production of remaining reserves. At September 30, 2011 and 2010, the Company had no material natural gas imbalances.

Concentration of Credit Risk

Substantially all of the Company's accounts receivable are due from purchasers of oil and natural gas or operators of the oil and natural gas properties. Oil and natural gas sales receivables are generally unsecured.

On July 22, 2008, SemGroup, L.P. and certain subsidiaries (SemGroup) filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As a result of the filing, the Company reserved $591,258 of receivables as uncollectible for substantially all of the sales of crude oil through various well operators to SemGroup during the period June 1, 2008 through July 22, 2008. The amount reserved was charged to bad debt expense in 2008. On October 28, 2009, the U.S. Bankruptcy Court confirmed the Fourth Amended Joint Plan of Affiliated Debtors, which set forth various settlement details for producers and interest owners. Based on the details of the plan, discussion with impacted operators and management's judgment, the Company lowered the reserve for doubtful accounts to $405,129 at September 30, 2009, resulting in $186,129 of bad debt recovery. The bankruptcy settlements were received during 2010 and early 2011 and the receivables and allowance for doubtful accounts were

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

completely relieved as of March 31, 2011.

Derivative contracts entered into by the Company are also unsecured.

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 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, 2011, the remaining carrying cost of non-producing oil and natural gas leases was $580,893.

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, 2010, the Company had outstanding letters of credit totaling $57,051 that expired in November 2010. As of September 30, 2011, the Company had no outstanding letters of credit.

Derivatives

The Company entered into oil costless collar contracts, natural gas fixed swap contracts and natural gas basis protection swaps. These instruments were 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 currently). 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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Bank of Oklahoma and are unsecured. The derivative instruments have settled or will settle based on the prices below, which are adjusted for location differentials and tied to certain pipelines in Oklahoma.

Derivative contracts in place as of September 30, 2010
(prices below reflect the Company's net price from the listed Oklahoma pipelines)

Contract period	Production volume covered per month	Indexed (1) Pipeline	Fixed price
Fixed price swaps			
January - December, 2010	100,000 Mmbtu	CEGT	$5.015
January - December, 2010	50,000 Mmbtu	CEGT	$5.050
January - December, 2010	100,000 Mmbtu	PEPL	$5.570
January - December, 2010	50,000 Mmbtu	PEPL	$5.560
Basis protection swaps			
January - December, 2011	50,000 Mmbtu	CEGT	NYMEX -$.27
January - December, 2011	50,000 Mmbtu	CEGT	NYMEX -$.27
January - December, 2011	50,000 Mmbtu	PEPL	NYMEX -$.26
January - December, 2011	50,000 Mmbtu	PEPL	NYMEX -$.27
January - December, 2012	50,000 Mmbtu	CEGT	NYMEX -$.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

(1) CEGT - Centerpoint Energy Gas Transmission's East pipeline in Oklahoma
PEPL - Panhandle Eastern Pipeline Company's Texas/Oklahoma mainline

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Derivative contracts in place as of September 30, 2011
(prices below reflect the Company's net price from the listed Oklahoma pipelines)

Contract period	Production volume covered per month	Indexed (1) Pipeline	Fixed price
Natural gas fixed price swaps			
April - October 2011	50,000 Mmbtu	NYMEX Henry Hub	$4.65
April - October 2011	50,000 Mmbtu	NYMEX Henry Hub	$4.65
April - October 2011	50,000 Mmbtu	NYMEX Henry Hub	$4.70
April - October 2011	50,000 Mmbtu	NYMEX Henry Hub	$4.75
May - October 2011	50,000 Mmbtu	NYMEX Henry Hub	$4.50
May - October 2011	50,000 Mmbtu	NYMEX Henry Hub	$4.60
June - October 2011	50,000 Mmbtu	NYMEX Henry Hub	$4.63
Natural gas basis protection swaps			
January - December, 2011	50,000 Mmbtu	CEGT	NYMEX -$.27
January - December, 2011	50,000 Mmbtu	CEGT	NYMEX -$.27
January - December, 2011	50,000 Mmbtu	PEPL	NYMEX -$.26
January - December, 2011	50,000 Mmbtu	PEPL	NYMEX -$.27
January - December, 2011	70,000 Mmbtu	PEPL	NYMEX -$.36
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
Oil costless collars			
April - December, 2011	5,000 Bbls	NYMEX WTI	$100 floor/$112 ceiling

(1) CEGT - Centerpoint Energy Gas Transmission's East pipeline in Oklahoma
PEPL - Panhandle Eastern Pipeline Company's Texas/Oklahoma mainline

While the Company believes that its derivative contracts are effective in achieving the risk management objective for which they were intended, 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 $215,940 as of September 30, 2011, and an asset of $1,620,326 as of September 30, 2010. Realized and unrealized gains and (losses) are scheduled below:

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Gains (losses) on natural gas derivative contracts	Fiscal year ended 9/30/2011	9/30/2010	9/30/2009
Realized	$ 2,138,685	$ 2,209,900	$ 2,497,800
Increase (decrease) in fair value	(1,404,386)	4,133,761	(3,159,628)
Total	$ 734,299	$ 6,343,661	$ (661,828)

To the extent that a legal offset exists, the Company nets the fair value of its derivative contracts with the same counterparty in the accompanying balance sheets. The following table summarizes the Company's derivative contracts as of September 30, 2011, and September 30, 2010:

	Balance Sheet Location	9/30/2011 Fair Value	9/30/2010 Fair Value
Asset Derivatives:			
Derivatives not designated as Hedging Instruments:			
Commodity contracts	Short-term derivative contracts	$ 269,329	$ 1,481,527
Commodity contracts	Long-term derivative contracts	-	138,799
Total Asset Derivatives (a)		$ 269,329	$ 1,620,326
Liability Derivatives:			
Derivatives not designated as Hedging Instruments:			
Commodity contracts	Short-term derivative contracts	$ -	$ -
Commodity contracts	Long-term derivative contracts	53,389	-
Total Liability Derivatives (a)		$ 53,389	$ -

(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

Accounting literature has established a framework for measuring fair value which defines fair value 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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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. Counterparty quotes are generally assessed as a Level 3 input.

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, 2011			
	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	$ -	$ (77,907)	$ -	$ (77,907)
Derivative Contracts - Collars	$ -	$ -	$ 293,847	$ 293,847

	Fair Value Measurement at September 30, 2010			
	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	$ -	$ 1,620,326	$ -	$ 1,620,326

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, among other things, future prices and time to maturity. These values are then compared to the values given by our counterparties for reasonableness.

Level 3 – The fair values of the Company's oil 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, among other things, future prices, volatility and time to maturity. These values are then compared to the values given by our counterparties for reasonableness.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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

	Derivatives
Balance of Level 3 as of October 1, 2010	$ -
Total gains or (losses) - realized and unrealized:	
Included in earnings	393,992
Included in other comprehensive income (loss)	-
Purchases, issuances and settlements	(100,145)
Transfers in and out of Level 3	-
Balance of Level 3 as of September 30, 2011	$ 293,847

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,			
	2011		2010	
	Fair Value	Impairment	Fair Value	Impairment
Producing Properties	$ 1,811,709	$ 1,728,162	$ 313,248	$ 605,615 (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 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. As a result, the Company recorded $1,728,162 and $605,615 in impairment charges during 2011 and 2010.

Fair Values of Financial Instruments

The carrying amounts reported in the balance sheets for cash and cash equivalents, receivables, derivative contracts, refundable income taxes, accounts payable and accrued liabilities approximate their fair values due to the short maturity of these instruments. The fair value of Company's debt approximates its carrying amount due to the interest rates on the Company's revolving line of credit being rates, which are approximately equivalent to market rates for similar type debt based on the Company's credit worthiness.

Depreciation, Depletion, Amortization and Impairment

Depreciation, depletion and amortization of the costs of producing oil and natural gas properties are generally computed using the units of production method primarily on a separate property basis using proved or proved developed reserves, as applicable, as estimated by the Company's Independent

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Consulting Petroleum Engineer. 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 $5,215,239 and $4,346,191 at September 30, 2011 and 2010, respectively, consisting of perpetual ownership of mineral interests in several states, with 92% 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 85-year life of the Company. There are approximately 198,570 net acres of non-producing minerals in more than 6,900 tracts owned by the Company. An average tract contains approximately 29 acres, and the average cost per acre is $39. 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, 2011, is based on the best information available as of that date, including estimates of forward oil 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 $1,728,162, $605,615 and $2,464,520 respectively, for 2011, 2010 and 2009. A significant reduction in oil 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.

Capitalized Interest

During 2011, 2010 and 2009, interest of $0, $104,100 and $455,516, respectively, was included in the Company's capital expenditures. Interest of $0, $60,912 and $6,946, 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 units 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 five percent or greater, but does not have control of the partnership or LLC, are accounted for using the equity method of accounting.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 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 plugging liabilities.

The following table shows the activity for the years ended September 30, 2011 and 2010, relating to the Company's retirement obligation for plugging liability:

	2011	2010
Plugging Liability as of beginning of the year	$ 1,730,369	$ 1,620,225
Accretion of Discount	109,198	106,093
New Wells Placed on Production	28,624	20,476
Wells Sold or Plugged	(24,316)	(16,425)
Plugging Liability as of end of the year	$ 1,843,875	$ 1,730,369

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 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, 2011 and 2010, 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, including unissued, vested directors' shares during the period. The Company's restricted stock awards are not included in the diluted earnings per share calculation.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 during 2010 and 2011 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 matters. 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 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 2007.

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, 2011, 2010 and 2009, the Company recorded interest and penalties of $21,000, $0 and $0, respectively. The Company does not believe it has any significant uncertain tax positions.

New Accounting Standards

In June 2011, the FASB issued Accounting Standards Update 2011-05, *Presentation of Comprehensive Income*. This update provides the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The Company does not believe that this will materially impact the presentation of its financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

In May 2011, the FASB issued Accounting Standards Update 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*. This update does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. This update may require certain additional disclosures related to fair value measurements. We do not expect the adoption of this update will materially impact our financial statement disclosures.

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 2012. Future minimum rental payments under the terms of the lease are $119,052 in 2012. Total rent expense incurred by the Company was $204,089 in 2011, $203,939 in 2010 and $200,627 in 2009.

3. INCOME TAXES

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

	2011	**2010**	**2009**
Current:			
Federal	$ 1,266,000	$ 3,950,000	$ 1,246,000
State	48,000	174,000	-
	1,314,000	4,124,000	1,246,000
Deferred:			
Federal	1,982,000	708,000	(3,254,000)
State	(104,000)	69,000	(560,000)
	1,878,000	777,000	(3,814,000)
	$ 3,192,000	$ 4,901,000	$ (2,568,000)

3. INCOME TAXES (CONTINUED)

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:

	2011	2010	2009
Provision (benefit) for income taxes at statutory rate	$ 4,090,069	$ 5,712,242	$ (1,690,827)
Percentage depletion	(733,516)	(684,053)	(469,962)
State income taxes, net of federal provision (benefit)	(92,989)	325,000	(451,440)
State net operating loss carryforward benefit	-	-	(154,000)
State net operating loss valuation allowance (release)	31,000	(278,000)	278,000
Other	(102,564)	(174,189)	(79,771)
	$ 3,192,000	$ 4,901,000	$ (2,568,000)

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:

	2011	2010
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$ 26,939,720	$ 24,141,021
Derivative contracts	84,001	630,307
	27,023,721	24,771,328
Deferred tax assets:		
State net operating loss carry forwards, net of valuation allowance of $31,000 in 2011 and $0 in 2010	1,130,732	825,048
Deferred directors compensation	986,340	813,836
Other	121,899	225,694
	2,238,971	1,864,578
Net deferred tax liabilities	$ 24,784,750	$ 22,906,750

At September 30, 2011, the Company had an income tax benefit of $1,161,732 related to Oklahoma state income tax net operating loss (OK NOL) carryforwards expiring from 2016 to 2031. A valuation allowance of $31,000 was recorded in the current year for the Oklahoma NOL's that management does not believe the Company will be able to realize before they expire.

4. LONG-TERM DEBT

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 which is subject to a semi-annual borrowing base determination, wherein BOK applies their own pricing forecast and a 9% discount rate to the Company's proved reserves as calculated by the Company's Independent Consulting Petroleum Engineering Firm.

4. LONG-TERM DEBT (CONTINUED)

When applying the discount rate, BOK also applies an advance rate percentage to risk 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 $27,167,044 at September 30, 2011. The facility matures on November 30, 2014. The interest rate is based on national prime plus from .50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%. 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. There were no borrowings outstanding under the revolving loan as of September 30, 2011 and 2010.

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. The credit facility 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, 2011, the Company was in compliance with the covenants of the credit facility.

5. SHAREHOLDERS' EQUITY

Upon approval by the shareholders of the Company's 2010 Restricted Stock Plan on March 11, 2010, the board of directors 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 of directors' 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 of directors. 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 of directors determine otherwise. Pursuant to previously adopted board resolutions, the purchase of an additional $1.5 million of the Company's Common Stock became authorized and approved effective March 29, 2011. As of September 30, 2011, $2,142,672 had been spent under the current program to purchase 77,807 shares. The shares are held in treasury and are accounted for using the cost method. On September 30, 2011, 2010 and 2009, 10,710, 11,632 and 11,508 (respectively) treasury shares were contributed to the Company's ESOP on behalf of the ESOP participants.

6. EARNINGS PER SHARE

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

	Year ended September 30,		
	2011	2010	2009
Numerator for basic and diluted earnings per share:			
Net income (loss)	$ 8,493,912	$ 11,419,690	$ (2,405,021)
Denominator for basic and diluted earnings per share - weighted average shares (including for 2011, 2010 and 2009, unissued, vested directors' shares of 122,728, 111,491 and 97,177, respectively)	8,393,890	8,422,387	8,397,337

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 its employees. Company contributions are made at the discretion of the Board of Directors 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 salaries 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 amongst 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 255,333 shares of the Company's Common Stock held by the plan, as of September 30, 2011, 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
2011	10,710	$ 303,843
2010	11,632	$ 287,194
2009	11,508	$ 245,811

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 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, 2011, there were 129,776 shares (114,323 shares at September 30, 2010) included in the Plan. The deferred balance outstanding at September 30, 2011 under the Plan was $2,665,583 ($2,222,127 at September 30, 2010). Expenses totaling $443,456, $359,628 and $256,688 were charged to the Company's results of operations for the years ended September 30, 2011, 2010 and 2009, 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 that 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 awarded 8,500 shares of the Company's Common Stock as restricted stock to certain officers. The restricted stock vests at the end of five years and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. The fair value of the shares at the time of their award, based on the closing price of the shares on their award date, was $240,550 and will be recognized as compensation expense ratably over the vesting period.

On December 21, 2010, the Company awarded 8,780 shares of the Company's Common Stock as restricted stock to certain officers. The restricted stock vests at the end of three years and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. The fair value of the shares at the time of their award, based on the closing price of the shares on their award date, was $245,840 and will be recognized as compensation expense ratably over the vesting period.

The compensation expense recognized as part of general and administrative expense for these awards in 2011 was $109,573. As of September 30, 2011, there was $364,790 of total unrecognized compensation cost related to these awards. The cost is to be recognized over a weighted average period of 2.98 years. 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 during 2011 is presented below:

	Unvested Restricted Shares	**Weighted Average Grant-Date Fair Value**
Unvested shares as of October 1, 2010	8,500	$ 28.30
Granted	8,780	$ 28.00
Vested	-	$ -
Forfeited	-	$ -
Unvested shares as of September 30, 2011	17,280	$ 28.15

On December 21, 2010, the Company also awarded 8,782 shares of the Company's Common Stock, subject to certain share price performance standards, 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 (three years). 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

9. RESTRICTED STOCK PLAN (CONTINUED)

and is recognized over the vesting period (three years) regardless of whether performance shares are awarded at the end of the vesting period. The impact of these awards on general and administrative expense in 2011 was $42,909. As of September 30, 2011, there was $128,727 of total unrecognized compensation cost related to this performance-based, restricted stock. The cost is to be recognized over a weighted average period of 2.24 years. Upon vesting, shares are expected to be issued out of shares held in treasury.

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.

During 2011, 2010 and 2009, approximately 15%, 14% and 20%, respectively, of the Company's total revenues were derived from sales through Chesapeake Operating, Inc. During 2011, 2010 and 2009, approximately 7%, 11% and 14%, respectively, of the Company's total revenues were derived from sales through JMA Energy Company. During 2011, 2010 and 2009, approximately 14%, 15% and 17% of the Company's total revenues were derived from sales through Newfield Exploration.

11. SUPPLEMENTARY INFORMATION ON OIL 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:

	2011	2010
Producing properties	$ 230,554,198	$ 207,928,578
Non-producing minerals	8,792,980	7,744,767
Non-producing leasehold	1,102,988	1,360,264
Exploratory wells in progress	1,204,382	511,299
	241,654,548	217,544,908
Accumulated depreciation, depletion and amortization	(145,664,726)	(131,529,373)
Net capitalized costs	$ 95,989,822	$ 86,015,535

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

Costs Incurred

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

	2011	2010	2009
Property acquisition costs	$ 5,140,862	$ 742,005	$ 382,239
Exploration costs	4,837,451	530,931	1,647,456
Development costs	17,310,808	10,685,088	26,411,704
	$ 27,289,121	$ 11,958,024	$ 28,441,399

Approximately $3.9 million of 2011 property acquisition costs relates to the acquisition of mineral acreage with proved reserves.

The following unaudited information regarding the Company's oil 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

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

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 and natural gas reserves as of September 30, 2011 and 2010 (see Exhibits 23 and 99). Reserves as of September 30, 2009, were calculated by Pinnacle Energy Services, L.L.C. of Oklahoma City, Oklahoma.

The Company's net proved oil and natural gas reserves, all of which are located in the United States, as of September 30, 2011, 2010 and 2009, have been estimated by the Company's Independent Consulting Petroleum Engineering Firms (as noted above). All studies have been prepared in accordance with regulations prescribed by the SEC and generally accepted geological and engineering methods by the petroleum industry.

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 25 years of oil and gas industry experience, including engineering assignments in several field locations.

Our COO and internal staff of professionals 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 value based 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.

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

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.

Estimated Quantities of Proved Oil and Natural Gas Reserves

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

	Proved Reserves		
	Oil (Barrels)	**NGL (1) (Barrels)**	**Natural Gas (Mcf)**
September 30, 2008	989,957	-	48,150,671
Revisions of previous estimates	(30,266)	-	589,308
Divestitures	(3,593)	-	(316,884)
Extensions and discoveries	92,935	-	14,714,703
Production	(128,160)	-	(9,109,988)
September 30, 2009	920,873	-	54,027,810
Revisions of previous estimates	47,999	-	15,762,883
Divestitures	(487)	-	(7,778)
Extensions and discoveries	59,003	-	36,689,882
Production	(102,379)	-	(8,302,342)
September 30, 2010	925,009	-	98,170,455
Revisions of previous estimates	(59,360)	791,648	769,676
Acquisitions	-	-	3,189,520
Extensions and discoveries	82,230	-	8,005,990
Production	(104,141)	-	(8,297,657)
September 30, 2011	843,738	791,648	101,837,984

(1) 2011 is 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 Oklahoma, which includes many plays (horizontal Granite Wash, Hogshooter Wash, Cleveland, Marmaton, Tonkawa and the Anadarko Basin "Cana" Woodford Shale) producing significant volumes of NGL.

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

The prices used to calculate reserves and future cash flows from reserves for oil, natural gas liquids and natural gas, respectively, were as follows: September 30, 2011 - $90.28/Bbl, $38.91/Bbl, $3.81/Mcf. The prices used to calculate reserves and future cash flows from reserves for oil and natural gas, respectively, were as follows: September 30, 2010 - $69.23/Bbl, $4.33/Mcf; September 30, 2009 - $66.96/Bbl, $2.86/Mcf (these natural gas prices are representative of local pipelines in Oklahoma).

The revisions of previous estimates were primarily the result of:

(1) Positive performance revisions of 9,681,460 Mcfe, which were principally attributable to properties in the southeast Oklahoma Woodford Shale and the Arkansas Fayetteville Shale. These revisions are principally the result of actual well performance on both new and existing wells exceeding the performance projections in the prior estimates. The improved performance in the new wells can be attributed to enhanced fracture stimulation and completion techniques and increased horizontal lateral lengths.

(2) Revisions related to the inclusion of natural gas liquids and the associated reduction in natural gas volumes due to the conversion of previously reported gas volumes into NGL volumes. The Company reported NGL reserves for the first time in the 2011 year-end report. Panhandle's increased drilling activity over the last 12-18 months in several western Oklahoma plays which produce significant NGL, have resulted in meaningful NGL production and reserves for the Company, necessitating inclusion in the reserve calculation.

(3) Negative gas pricing revisions of 8,911,784 Mcfe, which included revisions due to producing wells reaching their economic limits earlier than previously projected and revisions due to proved undeveloped locations, primarily in the southeast Oklahoma Woodford Shale, becoming uneconomic at current product prices.

Extensions and discoveries are principally attributable to:

(1) The Company's ongoing development of unconventional natural gas and natural gas liquids plays utilizing horizontal drilling, including the Anadarko Basin Woodford Shale.

(2) The Company's ongoing development of unconventional natural gas plays utilizing horizontal drilling, including the Arkansas Fayetteville Shale and the southeast Oklahoma Woodford Shale.

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

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

	Proved Developed Reserves			Proved Undeveloped Reserves		
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)
September 30, 2009	882,987	-	45,036,460	37,886	-	8,991,350
September 30, 2010	861,240	-	57,344,190	63,769	-	40,826,265
September 30, 2011	759,989	386,774	60,193,878	83,749	404,874	41,644,106

The following details the changes in proved undeveloped reserves for 2011 (Mcfe):

Beginning proved undeveloped reserves	41,208,879
Proved undeveloped reserves transferred to proved developed	(5,190,555)
Revisions	995,953
Extensions and discoveries	4,744,630
Purchases	2,816,937
Ending proved undeveloped reserves	44,575,844

The beginning 2011 PUD reserves were 41,208,879 Mcfe. A total of 5,190,555 Mcfe (12.6% of the beginning balance) were transferred to proved developed during 2011. An additional 5,553,576 Mcfe (13.5% of the beginning balance) were removed during 2011 as the result of becoming uneconomic at 2011 product prices. A total of 10,744,131 Mcfe (26.1% of the beginning balance) of PUD reserves were moved out of the category during 2011 as the result of either being transferred to proved developed or removed as uneconomic. Only one PUD location from 2007 and one PUD location from 2008 remain in the PUD category. We anticipate that all the Company's remaining PUD locations will be drilled and converted to PDP within 5 years of the date they were added. However, 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 as of September 30, 2010 and 2011, are determined by applying the trailing unweighted 12-month arithmetic average of the first-day-of-the-month oil and natural gas prices and year-end costs to the estimated quantities of natural gas and oil 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 oil and natural gas prices and year-end costs used. Amounts as of September 30, 2009, were determined using year-end prices and costs. 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.

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

Estimated future income taxes are computed using current statutory income tax rates including consideration for the current tax basis of the properties and related carryforwards, 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.

	2011	2010	2009
Future cash inflows	$ 494,523,456	$ 489,691,155	$ 216,181,210
Future production costs	146,168,829	148,727,914	62,102,230
Future development costs	43,425,811	52,975,820	5,412,470
Asset retirement obligation	1,843,875	1,730,369	1,620,225
Future income tax expense	107,111,317	99,118,090	43,832,666
Future net cash flows	195,973,624	187,138,962	103,213,619
10% annual discount	117,591,190	114,638,553	49,467,111
Standardized measure of discounted future net cash flows	$ 78,382,434	$ 72,500,409	$ 53,746,508

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

	2011	2010	2009
Beginning of year	$ 72,500,409	$ 53,746,508	$ 78,794,725
Changes resulting from:			
Sales of oil and natural gas, net of production costs (1)	(33,570,621)	(34,429,083)	(28,524,453)
Net change in sales prices and production costs	(2,697,833)	30,806,970	(59,790,799)
Net change in future development costs	4,177,910	(26,093,254)	7,769,930
Net change in asset retirement obligation	(51,098)	(48,185)	(63,536)
Extensions and discoveries	11,938,029	53,274,047	21,677,448
Revisions of quantity estimates	7,046,873	28,946,810	587,215
Acquisitions/divestitures of reserves-in-place	4,480,858	(15,706)	(480,535)
Accretion of discount	12,523,091	8,066,959	12,110,733
Net change in income taxes	(5,329,092)	(25,807,417)	15,389,517
Change in timing and other, net	7,363,908	(15,947,240)	6,276,263
Net change	5,882,025	18,753,901	(25,048,217)
End of year	$ 78,382,434	$ 72,500,409	$ 53,746,508

(1) Sales of natural gas includes associated natural gas liquids

12. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

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

	Fiscal 2011			
	Quarter Ended			
	December 31	**March 31**	**June 30**	**September 30**
Revenues	$ 9,901,548	$ 10,977,459	$ 11,688,417	$ 12,409,227
Income before provision for income taxes	$ 2,002,849	$ 2,271,253	$ 3,691,429	$ 3,720,381
Net income	$ 1,426,849	$ 1,772,253	$ 2,650,429	$ 2,644,381
Earnings per share	$ 0.17	$ 0.21	$ 0.32	$ 0.31

	Fiscal 2010			
	Quarter Ended			
	December 31	**March 31**	**June 30**	**September 30**
Revenues	$ 12,321,352	$ 16,856,884	$ 10,461,870	$ 12,298,310
Income (loss) before provision for income taxes	$ 2,411,378	$ 6,964,566	$ 2,264,300	$ 4,680,446
Net income (loss)	$ 1,708,378	$ 5,163,566	$ 1,511,300	$ 3,036,446
Earnings (loss) per share	$ 0.20	$ 0.61	$ 0.18	$ 0.36

13. SUBSEQUENT EVENTS

The Company closed an acquisition on October 25, 2011, of certain Fayetteville Shale assets located in Van Buren, Conway and Cleburne Counties, Arkansas, in the core of the Fayetteville Shale. The Company acquired an average working interest of 2.3% in 193 producing non-operated natural gas wells and 1,531 acres of leasehold from a private seller. There are approximately 240 future infill drilling locations identified on the leasehold. The purchase price was $17.5 million and was funded by utilizing cash on hand and $13.3 million from the Company's bank credit facility.

Presented below is unaudited pro forma financial information assuming the Company had acquired this business as of the beginning of fiscal year ended September 30, 2011. The unaudited pro forma financial information is for informational purposes only and does not purport to present what our results would actually have been had this transaction actually occurred on the date presented or to project our results of operations or financial position for any future period. The pro forma financial information was not provided for the comparative periods, as the information could not be obtained from the seller.

13. SUBSEQUENT EVENTS (CONTINUED)

	2011 (unaudited)
Revenue:	
As reported	$ 44,976,651
Pro forma revenue	4,433,282
Pro forma	$ 49,409,933
Net Income:	
As reported	$ 8,413,912
Pro forma income	644,859
Pro forma	$ 9,058,771

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/Chief Executive Officer and Vice President/Chief Financial Officer, 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, 2011.

(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, 2011, 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 other 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)
(10.3) Purchase and Sale Agreement dated September 30, 2011 between Flatirons Development, LLC and Panhandle Oil and Gas Inc.
(23) Consent of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants
(31.1) Certification of Chief Executive Officer
(31.2) Certification of Chief Financial Officer
(32.1) Certification of Chief Executive Officer
(32.2) Certification of Chief Financial Officer
(99) Report of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants
(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

Dated August 2, 2011; item 5.02 – Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers

Dated August 2, 2011; item 5.03 – Amendments to Articles of Incorporation or Bylaws; Change in Fiscal Year

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
President;
Chief Executive Officer

Date: December 8, 2011

By: /s/ Lonnie J. Lowry
Lonnie J. Lowry
Vice President;
Chief Financial Officer

Date: December 8, 2011

By: /s/ Robb P. Winfield
Robb P. Winfield
Controller;
Chief Accounting Officer

Date: December 8, 2011

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.

/s/ Bruce M. Bell
Bruce M. Bell, Director

Date December 8, 2011

/s/ E. Chris Kauffman
E. Chris Kauffman, Director

Date December 8, 2011

/s/ Duke R. Ligon
Duke R. Ligon, Director

Date December 8, 2011

/s/ Robert O. Lorenz
Robert O. Lorenz, Lead Independent Director

Date December 8, 2011

/s/ Robert A. Reece
Robert A. Reece, Director

Date December 8, 2011

/s/ Robert E. Robotti
Robert E. Robotti, Director

Date December 8, 2011

/s/ Darryl G. Smette
Darryl G. Smette, Director

Date December 8, 2011

/s/ H. Grant Swartzwelder
H. Grant Swartzwelder, Director

Date December 8, 2011

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

November 22, 2011

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 September 30, 2011, 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, 2011, 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 t 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 8, 2011

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 8, 2011

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, 2011, 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 8, 2011

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, 2011, 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

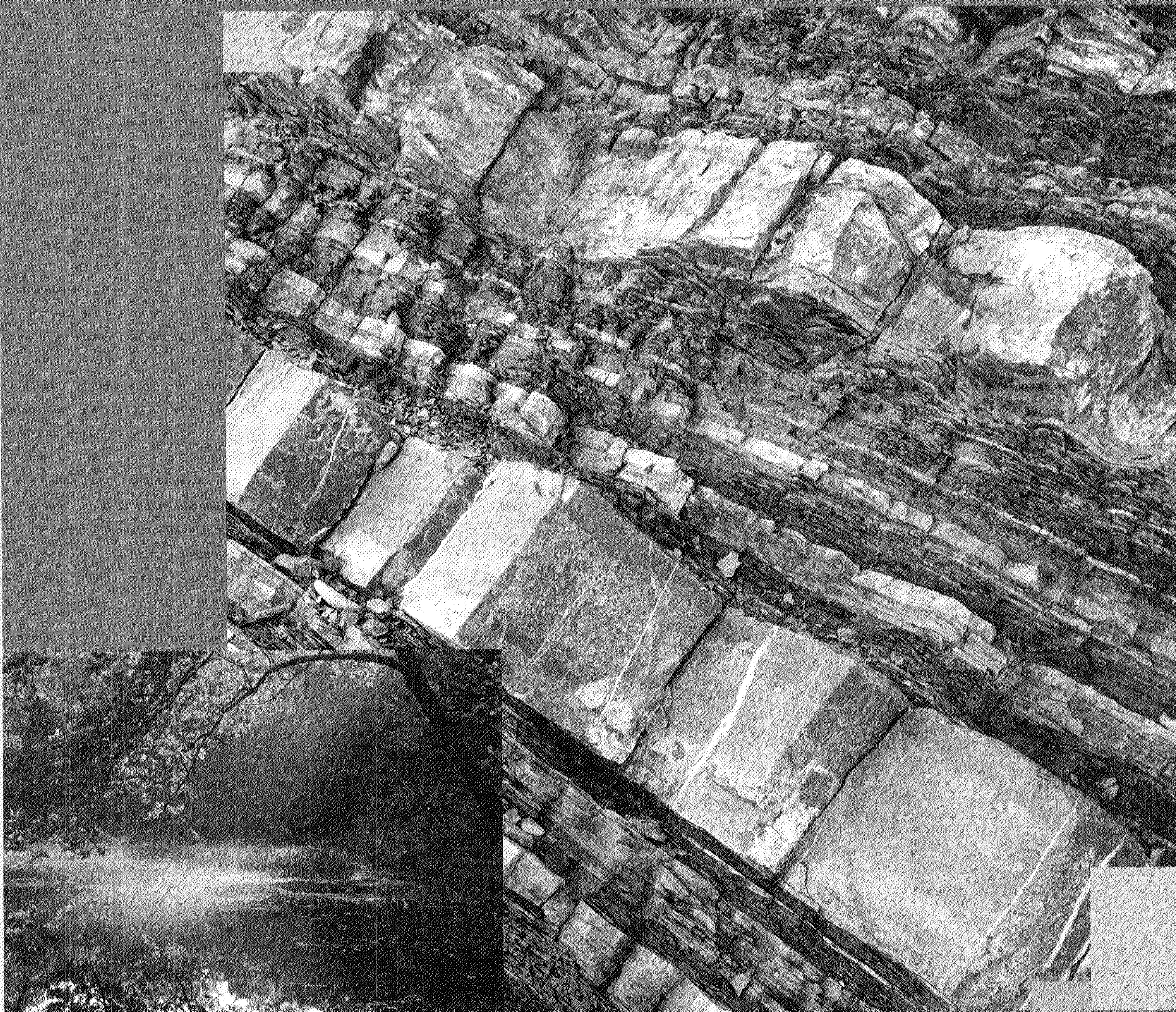
(2) The information contained in this Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

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

December 8, 2011

Cover photo: David G. Fitzgerald, photographer

The water from Antelope Springs flows into this pond.
Chickasaw National Recreation Area. Sulphur, Oklahoma.



Panhandle
Oil and Gas Inc.

5400 N. Grand Blvd., Suite 300
Oklahoma City, Oklahoma 73112
Phone: 405.948.1560
Fax: 405.948.1063
www.panhandleoilandgas.com