Panhandle Oil and Gas Inc.

2007 ANNUAL REPORT

Certain defined terms as used in this report: "**SEC**" means the United States Securities and Exchange Commission; "**Bbl**" means barrel; "**Bcf**" means billion cubic feet; "**Mcf**" means thousand cubic feet; "**Mcfd**" means thousand cubic feet per day; "**Mcfe**" means natural gas stated on an Mcf basis and crude oil converted to a thousand cubic feet of natural gas equivalent by using the ratio of one Bbl of crude oil to six Mcf of natural gas; "**PV-10**" means estimated pretax present value of future net revenues discounted at 10% using SEC rules; "**gross**" wells or acres are the wells or acres in which the Company has a working interest; and "**net**" wells or acres are determined by multiplying gross wells or acres by the Company's net revenue interest in such wells or acres. References to years 2003-2007 refer to the Company's fiscal years ended September 30 each year. "**Minerals**," "**mineral acres**" or "**mineral interests**" refers to fee mineral acreage owned in perpetuity by the Company. "**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. "**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.

To Our Shareholders

Our letter to shareholders serves two main purposes: First, to give you an understanding of the Company's achievements during fiscal 2007. Second, to look forward to what we believe will be the principal opportunities for Panhandle in the upcoming year.

Also, we would like to thank you, the Company's owners for voting to change the Company's name to Panhandle Oil and Gas Inc. This change has already had a positive impact on the perception of the Company.

2007 REVIEW

Fiscal 2007 was a year in which many of the strategic changes implemented in mid 2006 began to generate significant results. The most significant strategic change fully implemented in 2006-2007 was the decision to increase capital expenditures by taking larger interests in drilling opportunities on the Company's mineral property holdings as well as in selected drilling opportunities on leasehold acquired from other mineral owners. Capital committed to oil and gas activities has increased approximately 90% over the last two years. Over the last 80-plus years, there has been a tremendous amount of oil and gas produced from wells drilled on the Company's mineral properties. By taking a larger interest in new wells drilled on our mineral properties, we will be able to realize a significantly larger share of this production and reserves for Panhandle.

In fact, in 2007 the Company's oil and gas production increased 19% to 5,791,407 mcfe as compared to 4,881,976 mcfe for fiscal 2006. In addition total proved reserves at September 30, 2007, increased 22% to 41.9 bcfe as compared to 34.3 bcfe at September 30, 2006.

These increases were accomplished through the drill bit as there were no acquisitions of producing properties during the last two years.

Other operating highlights for 2007 include a reserve replacement percentage of 232% and a finding cost of approximately $2.10 per mcfe. Also, we used hedging (costless collar contracts) for the first time in fiscal 2007. We did this to reduce short-term fluctuations in our realized price of natural gas, thus lowering the Company's risk of suffering a severe reduction in cash flow that could have hampered our capital expenditure program. This hedging program generated cash payments to the Company of $658,400 during the year.

Financially, 2007 results were mixed. Net income was $6,343,464 as compared to net income in 2006 of $10,574,219. However, revenues increased in 2007 to $39,128,911 as compared to $37,485,680 in 2006 and cash flow from operations increased to $28,106,500 as compared to $23,470,145 in 2006.

Net income was negatively impacted by several non-cash charges including impairment charges of approximately $3,762,000 and higher than expected depreciation, depletion and amortization charges. These items as well as all revenue and expense items are fully discussed in the attached FORM 10-K under Item 7, Management's Discussion of Financial Conditions and Results of Operations.

The Company's share price closed out fiscal 2006 at $18.00 per share and increased during fiscal 2007 by 37% to end the year at $24.70 on September 30, 2007. As we write this letter in mid-December, the share price has increased

Panhandle Oil and Gas Inc.

to approximately $27.00. We are happy that Panhandle's stock continued to perform positively in spite of declining natural gas prices in 2007 as compared to 2006. We look forward to continued positive stock price performance in 2008 and the years ahead as our strategy changes continue to be executed.

LOOKING FORWARD

Panhandle is fortunate to have significant mineral acreage holdings (for a Company our size) in two of the industry's most active unconventional natural gas shale plays, the Woodford shale in southeast Oklahoma and the Fayetteville shale in Arkansas. The industry has known for a long time that these shales contained natural gas, but the increase in natural gas prices over the last several years and significant advancements in drilling and completion technologies have made producing this natural gas economically feasible.

Participating with a working interest in drilling in these shale plays will be the Company's principal focus in 2008. We will use our mineral acreage holdings to take the largest available and appropriate working interests. Drilling on the Company's minerals generates an increased rate of return, compared to drilling on leasehold, as Panhandle retains the royalty normally paid to the mineral owner. These two areas and a third project in western Oklahoma are discussed in more detail later in this report.

The two shale plays have the potential to significantly increase the value of Panhandle over the next few years. Based upon ultimate well densities per section in these plays, Panhandle has the potential to have an interest in several thousand wells over the life of these projects.

Panhandle anticipates committing approximately $42 million for new drilling in fiscal 2008. As Panhandle is a non-operator, it is difficult for us to predict which or how many wells will be drilled, but we expect approximately $25 million of capital commitments for wells in the two shale plays and the remaining $17 million to be committed principally for wells in the Dill City project and western Oklahoma. As the shale play drilling is repeatable with lower risk than many of our drilling opportunities we will be a very aggressive working interest participant in the development of our acreage. For this reason, the Company may utilize its line of credit on an as-needed basis, to help fund this drilling strategy. As always, we will continue to keep the Company's financial metrics strong. The results in this report demonstrate that Fiscal Year 2007 was the next step in what appears to be a very bright future for Panhandle.

Finally, it is with extreme sadness that we report the passing of Ben D. Hare in November. Ben was our friend and colleague, and he had a significant impact on the Company in a relatively short time. His passion and determination will be missed.

E. Chris Kauffman
Chairman

Michael C. Coffman
President, CEO

In Memoriam

Ben D. Hare

1945 – 2007

The Panhandle Oil and Gas family suffered a very real loss November 29, 2007, when Director Ben D. Hare died of complications from cancer.

A Certified Petroleum Geologist, Ben joined Panhandle as a director in 2002 and became Vice President/Chief Operating Officer in 2004. He served as Co-President from March 2006 through August 2007. He was instrumental in bringing new direction to this organization and in changing the company's name from Panhandle Royalty Company to Panhandle Oil and Gas Inc.

Ben was a member of the American Association of Petroleum Geologists and was honored with its distinguished service award in 2001. He is survived by his wife, Carol, sons Christopher and Patrick, two daughters-in-law, and two grandchildren.

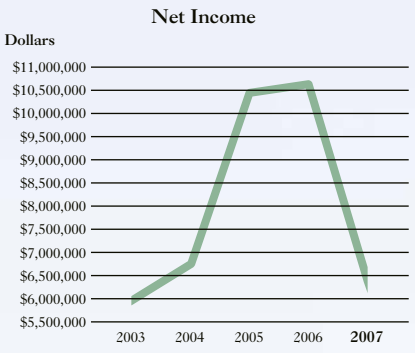
We will miss him.

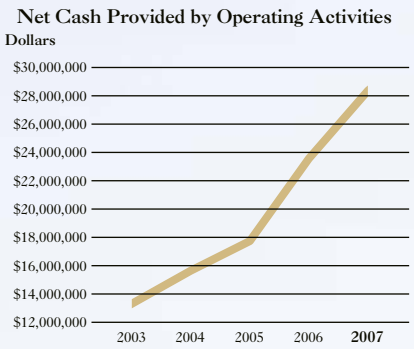
Financial and Operating Highlights

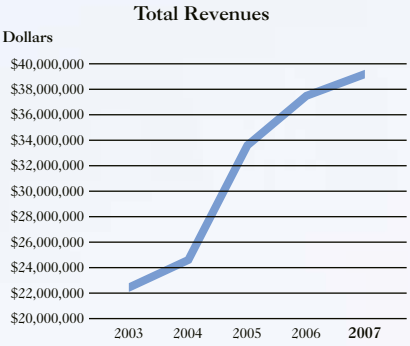
	2007	2006	2005
Revenue and Earnings			
Revenue	$ 39,128,911	$ 37,485,680	$ 33,598,175
Net Income	$ 6,343,464	$ 10,574,219	$ 10,484,786
Diluted Earnings per Share	$ .75	$ 1.25	$ 1.24
Average Diluted Shares Outstanding	8,499,233	8,479,406	8,450,238
Net Cash Provided by Operating Activities	$ 28,106,500	$ 23,470,145	$ 17,909,249
Expenditures for Oil and Gas Activities	$ 28,112,522	$ 22,624,040	$ 14,741,637

Reserves	2007	2006	2005
Proved Developed Reserves:			
Barrels of Oil	754,866	566,110	613,536
MCF of Gas	31,016,304	25,322,756	24,011,062
MCFE	35,545,500	28,719,416	27,692,278
Proved Undeveloped Reserves:			
Barrels of Oil	67,958	9,081	20,787
MCF of Gas	5,989,487	5,547,083	3,435,341
MCFE	6,397,235	5,601,569	3,560,063
Total Proved Reserves:			
Barrels of Oil	822,824	575,191	634,323
MCF of Gas	37,005,791	30,869,839	27,446,403
MCFE	41,942,735	34,320,985	31,252,341

10% Discounted Estimated Future Net Cash Flows (before federal income taxes @ SEC pricing)			
Proved Developed	$ 103,316,060	$ 62,920,576	$ 169,417,252
Proved Undeveloped	13,178,660	5,716,092	20,978,021
Total	$ 116,494,720	$ 68,636,668	$ 190,395,273
SEC Pricing			
Oil/Barrel	$ 78.93	$ 60.50	$ 64.18
Gas/MCF	$ 5.50	$ 3.49	$ 11.54







Production

	2007	2006	2005
MCFE Sold	5,791,407	4,881,976	4,620,712
Average Sales Price per MCFE	$ 6.47	$ 7.38	$ 6.54
Barrels Sold	107,344	97,139	101,581
Average Sales Price per Barrel	$ 62.81	$ 63.44	$ 51.30
MCF Sold	5,147,343	4,299,142	4,011,226
Average Sales Price per MCF	$ 5.97	$ 6.94	$ 6.24
Average Production Costs (per mcf equivalent)	$ 1.05	$ 1.08	$ 1.04

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

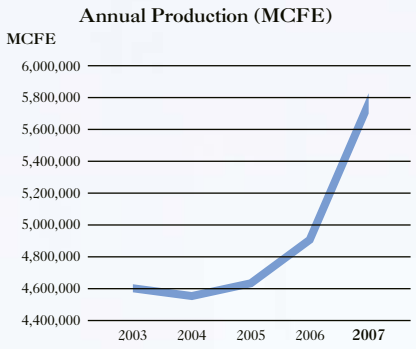
In 2007, Panhandle participated in 113 working interest wells that were completed, drilling or testing at year end, and had a royalty interest in 216 wells in the same categories

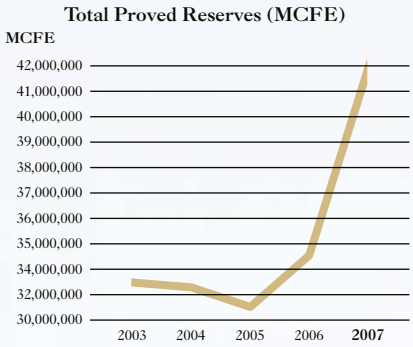
Working Interest Wells

Category	2007	2006	2005
Drilling	11	6	11
Testing	13	11	18
Producing	88 (10 oil, 78 gas)	98 (7 oil, 91 gas)	107 (9 oil, 98 gas)
Dry Holes	1	3	6
Total	113	118	142

Royalty Interest Wells

Category	2007	2006	2005
Drilling	19	22	14
Testing	1	2	30
Producing	188 (20 oil, 168 gas)	194 (21 oil, 173 gas)	143 (12 oil, 131 gas)
Dry Holes	8	17	14
Total	216	235	201





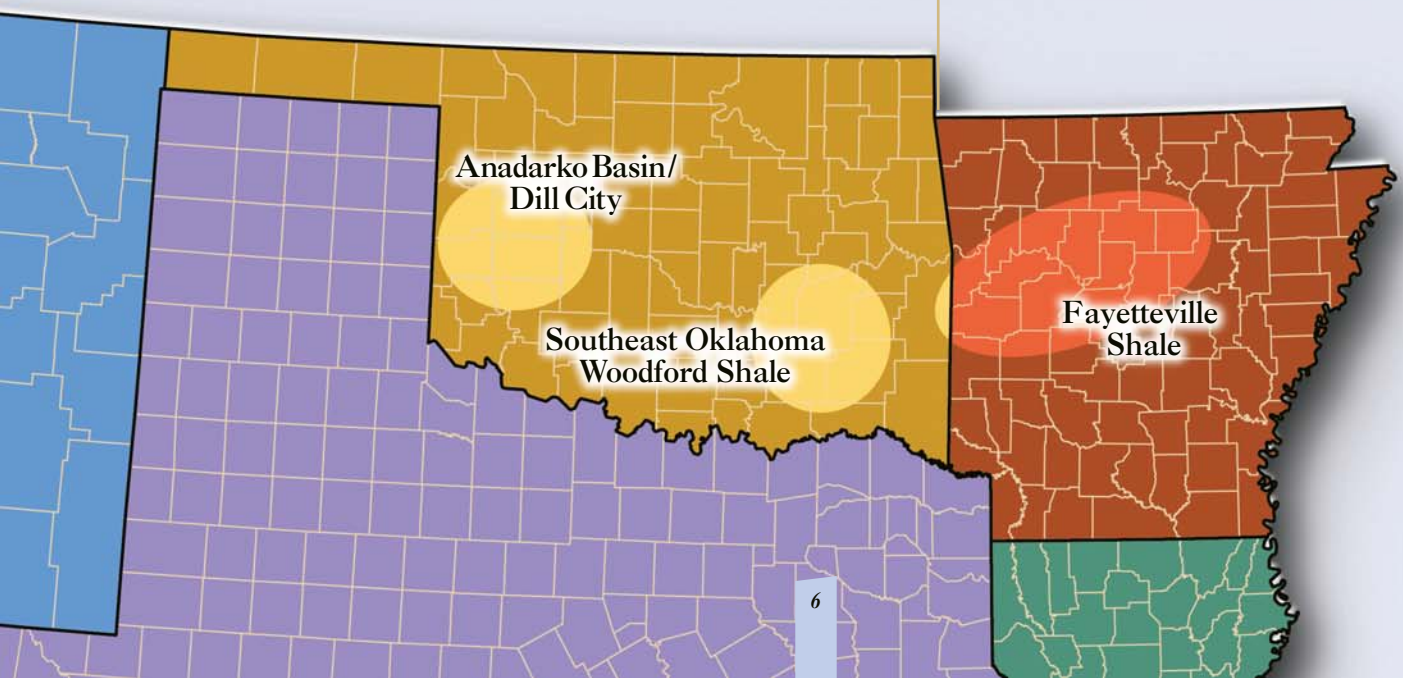
Operations Highlights

Fiscal 2007 will prove to be a very important year in the Company's history as strategy changes instituted in mid-2006 have begun to yield significant results. Fiscal 2007 results yielded the largest mcfe production and mcfe reserve volumes in the Company's history. The most meaningful of the strategy changes currently, and when fully implemented, is the increased working interest percentage being taken by the Company in new wells.

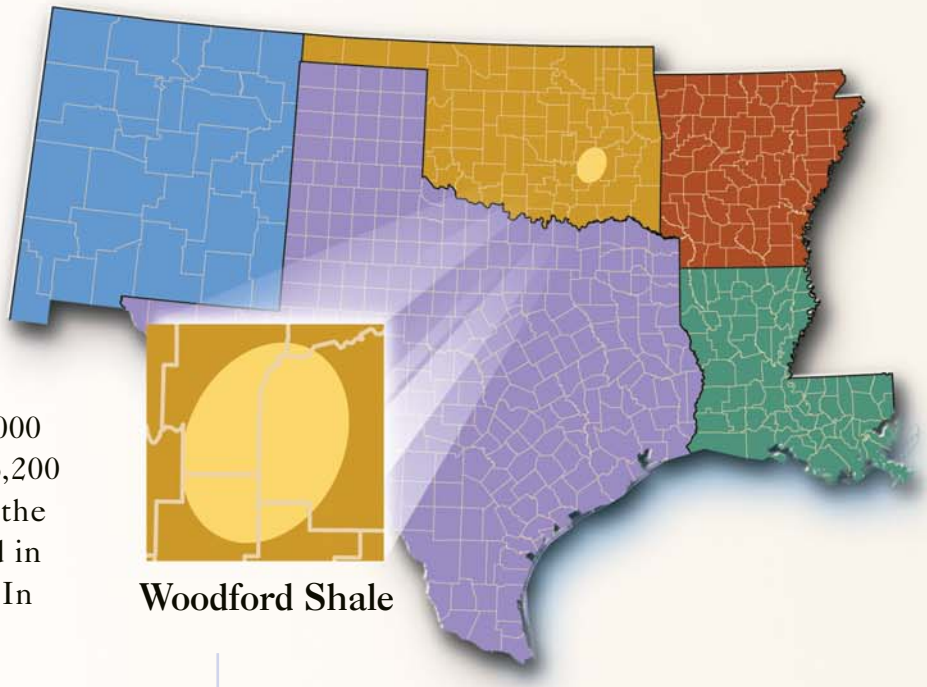
These increased working interests are principally a result of the Company using all its mineral interests to participate in wells drilled on its mineral acreage rather than drilling on a portion of the acreage and then leasing a portion to others. In addition, Panhandle is purchasing leasehold in certain areas in which the Company is actively drilling, either to supplement mineral acreage ownership or to give the Company drilling opportunities in areas in which there was no mineral acreage ownership.

The Company is committing to larger working interests in new wells being drilled and will be spending substantially more capital per well than in past years. Additional capital spending is the only way to achieve significant growth in the Company. An increase in spending could have taken either of two courses: larger interest in new drilling, or purchasing reserves and production. Management chose to concentrate on additional spending for new drilling due to the significant drilling opportunities the Company has with its mineral acreage in the Woodford and Fayetteville shales and on purchased leasehold in the Dill City prospect. These three areas are discussed in detail in this report. Acquisitions have not been ruled out, and those opportunities which may be of strategic significance will be evaluated for potential purchase.

PHX Significant Areas



Woodford Shale



Panhandle owns approximately 10,000 net mineral acres in the currently very active Woodford shale play located in Atoka, Coal, Hughes and Pittsburg counties, Oklahoma. Of the 10,000 acres, approximately 6,200 are in the core area of the play and are contained in 185 separate sections. In those 185 sections, Panhandle will have working interests and net revenue interests ranging from less than 1% to 35%, with the average net revenue interest in all 185 sections being approximately 3.9%.

These horizontally drilled wells use the latest drilling and completion technology and are very costly at $5-to-$6 million to the 100% interest. Completion technology continues to improve, which will translate into even better economics in future wells.

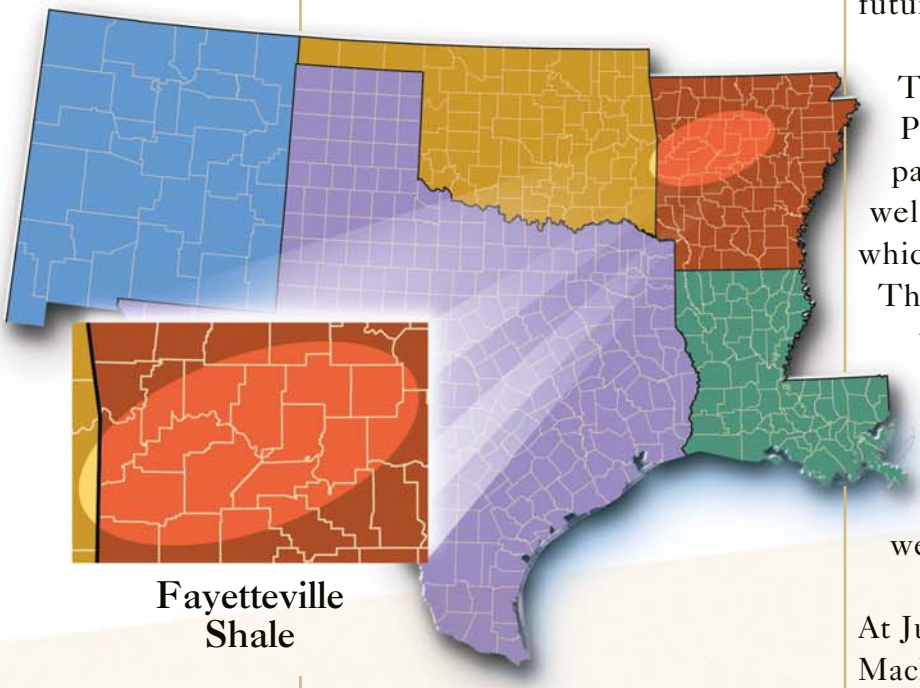
Through October 2007, the Company committed to participate with a working interest in 64 wells in the Woodford. Twenty-eight of those wells were already producing at that date. The average working interest and net revenue interest in the committed wells was approximately 8%. Approximately $17 million of fiscal 2007 capital commitments were for the Woodford shale wells.

At December 31, 2006, the independent engineering firm of DeGolyer and MacNaughton calculated probable reserves of 85 bcf and possible reserves of 45 bcf, net to Panhandle's interest, from the Woodford shale. These calculations were based on the Company's 6,200 net acres in the core area with average reserves per well estimated at 2.5 bcf and an assumed 80-acre well density.

Management anticipates fiscal 2008 and the next several years will bring increased drilling activity in the Woodford shale, and Panhandle will be participating aggressively in those drilling opportunities available to the Company.

Fayetteville Shale

Panhandle owns approximately 9,000 net mineral acres in Arkansas. Of these, approximately 7,800 are in the core area of the Fayetteville shale play, located in Cleburne, Conway, Faulkner, Johnson, Logan, Pope, Van Buren and Yale counties. Sixty-five percent of the 7,800 acres is in Conway and Van Buren counties. The entire 9,000 acres were leased out in fiscal 2005, but we retained the right to repurchase up to 50% of the acres in 67 sections where Panhandle ownership was over 40 acres in the section. This will allow the Company to participate with a working interest in those sections. In the other 200-plus sections the Company will have a royalty interest. The average net revenue interest in all 284 sections will be approximately 2%.



Again these are horizontally drilled wells, but are not as deep as the Woodford shale wells in Oklahoma. Completed well costs are in the $3.5 million range to the 100% interest. Again, completion technology is continuing to improve and should provide better economics on future wells.

Through October 2007, Panhandle committed to participate in 12 working interest wells in the Fayetteville, seven of which were producing at that date. The average working interest in the committed wells is 4.4% with an average net revenue interest of 5.2%. Approximately $1.2 million of fiscal 2007 capital commitments were in this area.

At July 1, 2007 DeGolyer and MacNaughton calculated probable reserves of 15 bcf and possible reserves of 28 bcf, net to Panhandle's interest, from the Fayetteville. These calculations were based on the Company's 7,800 net acres in the core area, average reserves of .8 bcf per well and nine wells per section.

Again, we anticipate fiscal 2008 and the next several years will bring increased drilling activity in the Fayetteville. As in the Woodford shale, Panhandle will aggressively participate in the opportunities available to the Company.

Anadarko Basin/Dill City

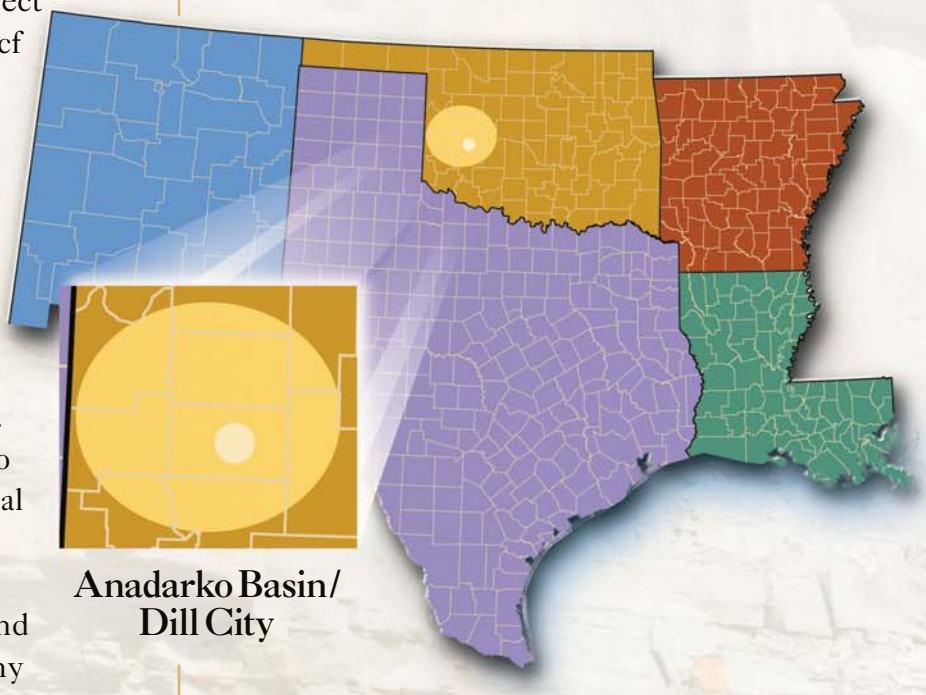
The Dill City project area in Washita County, Oklahoma, is a different type of play for Panhandle. It is being drilled essentially on leasehold acreage rather than owned mineral acres. The Company currently has significant leasehold ownership in 17 sections in this area. The average working interest in the current acreage held in the project area is approximately 16%.

These wells are vertically drilled wells for Atoka objectives at approximately 15,000 to 16,000 feet. The wells cost approximately $3.5 million to the 100% interest. At the end of October 2007, the Company had an interest in five new Atoka producers, with two wells completing, two wells drilling and nine wells scheduled. The best well in the Dill City prospect has made more than one bcf of gas and 60,000 barrels of oil since March 22, 2007.

Panhandle is seeking to purchase additional leasehold in the prospect area, but it is very competitive at this point. This area will continue to be very active through fiscal 2008, and has and will continue to contribute significant new reserves and production. The Company again will be aggressive in its drilling participations.

In other areas of western Oklahoma, the Company continues to develop its legacy assets (mineral acreage) by participating aggressively in economically viable projects proposed on the Company's mineral acreage. This area has been the Company's bread and butter area for many years and will continue to generate new reserves and production for the Company for many years.

With these projects, Panhandle has been presented an opportunity to add very significant reserves and production over the next several years. The Company is committed to maximizing these opportunities.

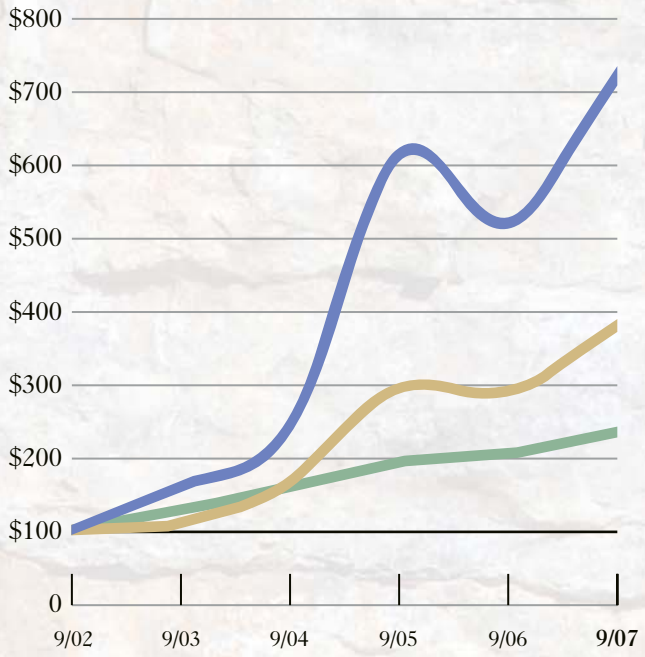


Comparison of 5 Year Cumulative Total Return*

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

The accompanying graph compares the cumulative 5-year total return provided shareholders on Panhandle Oil and Gas Inc.'s 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 9/30/2002 and its relative performance is tracked through 9/30/2007.

Panhandle Oil and Gas Inc.
S&P Smallcap 600
S&P Oil & Gas Exploration & Production



* $100 invested on 9/30/02 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 American 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, 2005	$ 22.00	$ 14.23
March 31, 2006	$ 23.50	$ 17.05
June 30, 2006	$ 22.50	$ 17.00
September 30, 2006	$ 19.78	$ 16.68
December 31, 2006	$ 19.75	$ 17.25
March 31, 2007	$ 20.68	$ 17.80
June 30, 2007	$ 28.80	$ 19.70
September 30, 2007	$ 28.60	$ 20.18

As of December 4, 2007, there were 1,826 holders of record of Panhandle's Class A Common Stock and approximately 3,000 beneficial owners.

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 2005	$ 0.025
March 2006	$ 0.08
June 2006	$ 0.04
September 2006	$ 0.04
December 2006	$ 0.04
March 2007	$ 0.07
June 2007	$ 0.07
September 2007	$ 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.

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

Ben Spriestersbach
Vice President, Land

Lonnie J. Lowry
Vice President,
Chief Financial Officer
and Secretary

Corporate Headquarters

Grand Centre Building
5400 North 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

Subsidiary

Wood Oil Company

Stock Exchange

American 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

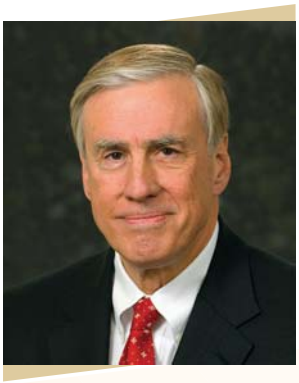
Panhandle Oil and Gas Inc.

Board of Directors

Bruce M. Bell
Edrio Oil Company
(2) (3) (4)

Michael C. Coffman
President
Chief Executive Officer

E. Chris Kauffman
Chairman of the Board
Campbell-Kauffman
Insurance Agency
(3)



Duke R. Ligon
Strategic Advisor
Love's Travel Shops &
Country Stores
(1) (2)

Robert O. Lorenz
Retired
(1) (2)

Robert A. Reece
Attorney
(1) (3) (4)

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

H. Grant Swartzwelder
Petrogrowth Advisors
(1) (2) (4)

(1) Member audit committee
(2) Member compensation committee
(3) Member retirement committee
(4) Member nominating committee

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

FORM 10-K

Annual Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended September 30, 2007

Commission File Number: 0-9116

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 North 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) — AMERICAN 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 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. X

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___

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, 2007, was $146,833,736. As of December 4, 2007, 8,431,502 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 6, 2008, 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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PART I

ITEM 1 BUSINESS

GENERAL

Panhandle Oil and Gas Inc. ("Panhandle" or the "Company") is an Oklahoma corporation organized in 1926 as Panhandle Cooperative Royalty Company. In 1979, Panhandle Cooperative Royalty Company was merged into Panhandle Royalty Company. Effective April 2, 2007, Panhandle Royalty Company changed its name to Panhandle Oil and Gas Inc. Panhandle's original authorized and registered stock consisted of 100,000 shares of $1.00 par value Class A Common Stock. In 1982, the Company split the stock on a 10-for-1 basis resulting in 1,000,000 shares of authorized Class A Common Stock. In May 1999, the Company's shareholders voted to increase the authorized Class A Common Stock to 6,000,000 shares and to split the shares on a three-for-one basis. In addition, voting rights for the shares were changed from one vote per shareholder to one vote per share. In February 2004, the Company's shareholders voted to increase the authorized Class A Common Stock to 12,000,000 shares and to split the shares on a two-for-one basis. In January 2006, the Class A Common Stock was again split on a two-for-one basis. In March 2007, the Company's shareholders voted to increase the authorized Class A Common Stock to the current 24,000,000 shares.

Since its formation, the Company has been involved in the acquisition, management and development of oil and gas properties, including wells located on the Company's mineral acreage. Panhandle's mineral properties and other oil and gas interests are located primarily in Arkansas, Kansas, Oklahoma, New Mexico and Texas. Properties are also located in seven other states. The majority of the Company's oil and gas production is from wells located in Oklahoma. In 1988, the Company merged with New Mexico Osage Royalty Company acquiring most of its New Mexico mineral acreage.

On October 1, 2001, Panhandle acquired privately held Wood Oil Company ("Wood") of Tulsa, Oklahoma. Prior to the acquisition, Wood was a privately held company engaged in oil and gas exploration and production and fee mineral ownership. Wood is operating as a wholly-owned subsidiary of Panhandle. Wood and its shareholders were unrelated parties to Panhandle.

The Company's office is located at Grand Centre, Suite 300, 5400 North Grand Blvd., Oklahoma City, OK 73112, (405)948-1560, fax (405)948-2038. Its website is located at www.panhandleoilandgas.com.

The Company files periodic SEC reports 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 electronically with the SEC. In addition, posted on the website are copies of the Company's various corporate governance documents. From time to time, other important disclosures to investors are provided by posting them 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 450 Fifth Street, N.W., 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 have been filed electronically with the SEC.

BUSINESS STRATEGY

The majority 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 gas holdings, including its mineral acreage, leasehold acreage and working and royalty interests in producing wells are mainly in Oklahoma with other significant holdings in Arkansas, Kansas, New Mexico and Texas. See “Item 2 - Description of Properties.” Exploration and development of the Company’s oil and gas properties are conducted in association with operating oil and gas companies, primarily larger independent companies. The Company does not operate any of its oil and 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 large percentage of the Company’s recent drilling participations have been on properties in which the Company has mineral acreage and, in many cases, already owns an interest in a producing well in the unit.

PRINCIPAL PRODUCTS AND MARKETS

The Company’s principal products are crude oil and natural gas. 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 properties in which it owns an interest, it relies on the operating expertise of numerous companies that operate in the areas where the Company owns interests. This expertise includes the drilling and completion of new wells, producing well operations and, in most cases, the marketing or purchasing of the well’s production. Natural gas sales are principally handled by the well operator and are normally contracted on a monthly basis with third party gas marketers and pipeline companies. Payment for gas sold is received 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 from the well operator or from the crude oil purchaser.

In general, prices of oil and gas are dependent on numerous factors beyond the control of the Company, such as 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 are subject to seasonal variations. The Company had not, through fiscal 2006, engaged in price hedging on its oil or gas production.

Beginning in calendar 2007, the Company has entered into hedging arrangements to reduce the Company’s exposure to short-term fluctuations in the price of natural gas. The hedging arrangements apply to only a portion of the Company’s production and provide only partial price protection against declines in natural gas prices. These hedging arrangements may expose the Company to risk of financial loss and limit the benefit of future increases in natural gas prices. A more thorough discussion of the hedging arrangements is contained in “Management’s Discussion and Analysis of Financial Condition and Results of Operation,” Item 7.

COMPETITIVE BUSINESS CONDITIONS

The oil and gas industry is highly competitive, particularly in the search for new oil and gas reserves. There are many factors affecting 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 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, weather patterns and actions taken by OPEC and other oil-producing countries have dramatic influence on the price Panhandle receives for its oil and gas production. The Company relies heavily on companies with greater resources, staff, equipment, research, and experience for operation of wells and the development and drilling of subsurface prospects. 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 method allows the Company to effectively compete 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 commercial quantities of oil and gas reserves is essential to the ultimate realization of value from the Company's mineral and leasehold acreage. These mineral properties and leasehold acreage may be considered a raw material to its 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 continues to reinvest a portion of its cash flow, after debt service, to the purchase of oil and gas leasehold acreage and, to a lesser extent, additional mineral 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 gas. This participation in exploration and production activities and the 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 purchases are made from many owners, and the Company does not rely on any particular companies or individuals for these acquisitions.

MAJOR CUSTOMERS

The Company's oil and gas production is sold, in most cases, by the well operators to many different purchasers on a well-by-well basis. During fiscal 2007, sales through two separate operators accounted for approximately 20% and 13%, respectively, of the Company's total revenues. Generally, if one purchaser declines to continue purchasing the Company's oil and natural gas, 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 gas wells stemming from the Company's ownership of mineral acreage generate a portion of the Company's revenues. These royalties are tied to the ownership of the mineral acreage and this ownership is perpetual, unless sold by the Company. Royalties are due and payable to the Company whenever oil and/or gas is produced from wells located on the Company's mineral acreage.

REGULATION

All of the Company's well interest and non-producing properties are located onshore in the United States. Oil and 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 and production of oil and gas. These states also have regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties and the regulation of spacing, plugging and abandonment of wells. As previously discussed, the well operators are relied upon by Panhandle to comply with governmental regulations.

Various aspects of the Company's oil and gas operations are regulated by agencies of the federal government. The 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 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 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 gas transporters. As a result of the various omnibus rulemaking proceedings in the late 1980's and the individual pipeline restructuring proceedings of the early to mid-1990's, 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) the large-scale divestiture of interstate pipeline-owned 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 available transportation information 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. What new or different regulations FERC and other regulatory agencies may adopt or what effect subsequent regulations may have on production and marketing of natural gas from the Company's properties 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. These regulations may tend to increase the cost of transporting oil by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. These regulations have generally been approved 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 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 these environmental laws will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future events. Since the Company does not operate any wells where 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 the Company believes the well operators to be in compliance with existing regulations and that absent an extraordinary event any noncompliance will not have a material adverse effect on the Company. Although the Company is not fully insured against all environmental risks, insurance is maintained which is customary in the industry.

EMPLOYEES

At September 30, 2007, Panhandle employed 18 persons on a full-time basis. Three of the employees are executive officers and 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.

Oil and natural gas prices are volatile. Volatility in oil and natural gas prices can adversely affect 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:

- relatively minor changes in the supply of and demand for oil and natural gas;
- market uncertainty;
- worldwide economic conditions;
- weather conditions;
- import prices;
- political conditions in major oil producing regions, especially the Middle East and West Africa;
- actions taken by OPEC;
- competition from alternative sources of energy; and
- economic, political and regulatory developments.

Price volatility makes it difficult to budget and project the return on exploration and development projects and to estimate with precision the value of producing properties that are owned or acquired. In addition, unusually 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. Quarterly results of operations may fluctuate significantly as a result of, among other things, variations in oil and natural gas prices and production performance. In recent years, oil and natural gas price volatility has become increasingly severe.

The Company's hedging activities may reduce the realized prices received for oil and natural gas sales.

In order to manage exposure to price volatility in our natural gas, we enter into natural gas price risk management arrangements (costless collars) for a portion of our expected production. Commodity price hedging may limit the prices we actually realize and therefore reduce oil and natural gas revenues in the future. The fair value of our natural gas derivative instruments outstanding as of September 30, 2007, was an asset of approximately $107,000.

A substantial or extended decline in oil and natural gas prices would have a material adverse effect on the Company.

A substantial or extended decline in oil and natural gas prices 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 negative effect in several ways, including:

- cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves or increase production;
- 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.

Lower oil and natural gas prices may cause impairment charges.

The Company has elected to utilize the successful efforts method of accounting for its oil and 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 as oil and gas is produced.

All long-lived assets, principally the Company's oil and gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than its future net cash flows. The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to oil and gas reserves. Any assets held for sale are reviewed for impairment when the Company approves the plan to sell. 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.

Although the Company's estimated oil and natural gas reserve data is prepared by a consulting engineering firm, estimates may still prove to be inaccurate.

The Company's fiscal 2007 reserve data represents the estimates of Pinnacle Energy Services, LLC, a consulting petroleum engineering firm. The Company's fiscal 2006 and 2005 reserve data represents the estimates of Campbell and Associates, a consulting petroleum engineering firm. Reserve estimates are prepared for all of the Company's properties annually by the consulting reservoir engineer with a limited review mid-year report also prepared. Incorporated into reserve estimates are many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices; and
- future development and operating costs.

Management believes the assumptions are reasonable based on the information available at the time of the estimates. However, actual results could vary considerably which could cause material variances in the estimated quantities of proved oil and natural gas reserves in the aggregate and for a particular geographic location or future net revenues, including production, revenues, taxes and development and operating expenditures. Any significant variation from these assumptions could result in the actual quantity of reserves and future net cash flows being materially different from the estimates. In addition, estimates of reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing oil and natural gas prices, operating and development costs and other factors. Because a complete review of reserve projections is only done at the end of the year, any material change in a reserve estimate is included in subsequent reserve reports.

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 successful exploration and development drilling, successfully applies new technologies or identifies additional behind-pipe zones or secondary recovery reserves. Future oil and natural gas production is therefore highly dependent upon the level of success in acquiring or finding additional reserves. The above activities must be done in conjunction with well operators, as the Company does not operate any of its wells.

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 net 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 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 or may be produced economically.

The ultimate cost of drilling, completing and operating a well is controlled by well operators and cost factors can adversely affect the economics of any project. 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 and the cost and availability of drilling rigs, equipment and services.

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 and the drilling of oil and natural gas wells, including well blowouts, cratering and explosions, pipe failures, fires, abnormal pressures, uncontrollable flows of oil, 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 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 upon the Company's financial results.

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 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 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 technology.

Shortages of oil field 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 and other equipment, as demand for rigs and equipment has 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 other independent oil and natural gas companies in each of the following areas:

- seeking to acquire desirable producing properties or new properties for future exploration; and
- seeking to acquire the equipment and expertise necessary to develop and operate properties.

Many of our competitors have financial and other resources substantially greater than ours, and some of them are fully integrated oil companies. These companies are able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully join in drilling with operators, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

ITEM 1B UNRESOLVED STAFF COMMENTS

None

ITEM 2 PROPERTIES

At September 30, 2007, Panhandle's principal properties consisted of perpetual ownership of 254,692 net mineral acres, held principally in tracts in Oklahoma, New Mexico, Texas and nine other states. The Company also held leases on 20,737 net acres of minerals primarily in Oklahoma. At September 30, 2007, Panhandle held royalty and/or working interests in 4,306 producing oil or gas wells, and 44 wells in the process of being drilled or completed.

Panhandle 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, few challenges have been made against the Company's fee title to its properties.

Panhandle pays ad valorem taxes on its minerals owned in certain states.

ACREAGE

Mineral Interests Owned

The following table of mineral interests owned reflects, at September 30, 2007, 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).

State	Net Acres	Gross Acres	Net Acres Prod'g (1)	Gross Acres Prod'g (1)	Net Acres Leased to Others (2)	Gross Acres Leased to Others (2)	Net Acres Open (3)	Gross Acres Open (3)
Arkansas	10,038	44,793	1,065	3,089	8,778	41,151	195	553
Colorado	8,326	39,299	109	219	30	200	8,187	38,880
Florida	5,602	12,239					5,602	12,239
Kansas	3,082	11,816	152	1,280			2,930	10,536
Montana	1,007	17,947			11	1,599	996	16,348
North Dakota	11,179	64,286			15	600	11,164	63,686
New Mexico	57,396	174,460	1,352	7,125	320	320	55,724	167,015
Oklahoma	113,013	940,145	32,481	265,472	3,259	27,759	77,273	646,914
South Dakota	1,825	9,300					1,825	9,300
Texas	43,180	361,444	7,216	68,510	598	4,909	35,366	288,025
OTHER	44	279					44	279
Total:	**254,692**	**1,676,008**	**42,375**	**345,695**	**13,011**	**76,538**	**199,306**	**1,253,775**

(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	Lease Acres Expiring			Net Acres Held by Production
		2008	2009	2010	
Kansas	2,117				2,117
Oklahoma	16,561	1,115	450	1,467	13,529
Texas	527	26	1	32	468
Other	1,532	92	67		1,373
TOTAL	20,737	1,233	518	1,499	17,487

PROVED RESERVES

The following table summarizes estimates of the proved reserves of oil and gas held by Panhandle. All reserves are located within the United States and are principally made up of small interests in approximately 4,300 individual wells. Because the Company's non-producing mineral and leasehold interests consist of various small interests in numerous tracts located primarily in Oklahoma, New Mexico and Texas and because the Company is a non-operator and must rely on third parties to propose and drill and operate producing wells, it is not feasible or possible to provide estimates of all proved undeveloped reserves and associated future net revenues. The Company is currently providing proved undeveloped reserve estimates for wells that it has a substantial reason to believe will be drilled in the very near term. In most cases, this means the Company has received some type of notice from the operator that a well will be drilled. All reserve quantity estimates for 2007 were prepared by Pinnacle Energy Services, LLC, Oklahoma City, Oklahoma, a consulting petroleum engineering firm. All reserve quantity estimates for 2006 and 2005 were prepared by Campbell and Associates, Norman, Oklahoma, a consulting petroleum engineering firm. Other than this report, the Company's reserve estimates are not filed with any other federal agency.

Proved Developed Reserves	Barrels of Oil	Mcf of Gas
September 30, 2007	754,866	31,016,304
September 30, 2006	566,110	25,322,756
September 30, 2005	613,536	24,011,062
Proved Undeveloped Reserves		
September 30, 2007	67,958	5,989,487
September 30, 2006	9,081	5,547,083
September 30, 2005	20,787	3,435,341
Total Proved Reserves		
September 30, 2007	822,824	37,005,791
September 30, 2006	575,191	30,869,839
September 30, 2005	634,323	27,446,403

These reserves exclude approximately 1.5 to 2.3 Bcf of CO2 gas reserves for the years presented.

Because the determination of reserves is a function of testing, evaluating, developing oil and gas reservoirs and establishing a production decline history, along with product price fluctuations, estimates will change as future information concerning individual reservoirs is developed and as market conditions change. Estimated reserve quantities and future net revenues are affected by changes in product prices, and these prices have varied substantially in recent years and are expected to vary substantially from current pricing in the future. Proved developed reserves are those expected to be recovered through existing well bores under existing economic and operating conditions. Proved undeveloped reserves are reserves that may be recovered from undrilled acreage or units, but are limited to those sites directly offsetting established production units, have sufficient geological data to indicate a reasonable expectation of commercial success and the Company has reason to believe will be drilled in the very near term.

ESTIMATED FUTURE NET CASH FLOWS

Set forth below are estimated future net cash flows with respect to Panhandle's proved reserves (based on the estimated units set forth in the immediately preceding table) for the fiscal year indicated, and the present value of such estimated future net cash flows, computed by applying a 10% discount factor as required by the rules and regulations of the SEC. Estimated future net cash flows have been computed by applying current prices at September 30 of each year to future production of proved reserves less estimated future expenditures to be incurred with respect to the development and production of such reserves. This pricing is based on SEC regulations. No federal or state income taxes are included in estimated costs. However, the amounts are net of operating costs and production taxes levied by the respective states. Prices used for determining future cash flows from oil and natural gas for the periods ended September 30, 2007, 2006, 2005 were as follows: 2007 - $78.93, $5.50; 2006 - $60.50, $3.49; 2005 - $64.18, $11.54. These future net cash flows 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 gas price increases or decreases.

Estimated Future Net Cash Flows (before federal income taxes)

	9-30-07	9-30-06	9-30-05
Proved Developed	$ 175,044,930	$ 94,939,418	$ 265,189,328
Proved Undeveloped	$ 23,046,080	$ 10,734,504	$ 31,671,502
Total Proved	$ 198,091,010	$ 105,673,922	$ 296,860,830

10% Discounted Present Value of Estimated Future Net Cash Flows (before federal income taxes)

	9-30-07	9-30-06	9-30-05
Proved Developed	$ 103,316,060	$ 62,920,576	$ 169,417,252
Proved Undeveloped	$ 13,178,660	$ 5,716,092	$ 20,978,021
Total Proved	$ 116,494,720	$ 68,636,668	$ 190,395,273

The future net cash flows are net of immaterial amounts of future cash flow to be received from CO2 reserves. The large decrease in the natural gas price at September 30, 2006, resulted in the decline of future net cash flows in 2006.

OIL AND GAS PRODUCTION

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

	Year Ended 9-30-07	Year Ended 9-30-06	Year Ended 9-30-05
Bbls - Oil	107,344	97,139	101,581
Mcf - Gas	5,147,343	4,299,142	4,011,226
Mcfe	5,791,407	4,881,976	4,620,712

Gas production includes 175,175, 192,957 and 183,743 Mcf of CO2 sold at average prices of $.61, $.65 and $.51 per Mcf for the years ended September 30, 2007, 2006 and 2005, respectively.

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 9-30-07	Year Ended 9-30-06	Year Ended 9-30-05
Per Bbl, Oil	$ 62.81	$ 63.44	$ 51.30
Per Mcf, Gas	$ 5.97	$ 6.94	$ 6.24
Per Mcfe	$ 6.47	$ 7.38	$ 6.54
Average Production (lifting costs)			
(Per Mcfe of Gas)			
(1)	$ 0.63	$ 0.63	$ 0.62
(2)	$ 0.42	$ 0.45	$ 0.42
	$ 1.05	$ 1.08	$ 1.04

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

Approximately 27% of the Company's oil and gas revenue is generated from small royalty interests in a few thousand wells. These 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 gas wells as of September 30, 2007. Panhandle owns fractional royalty interests or fractional working interests in these wells. The Company does not operate any wells.

	Gross Wells	Net Wells
Oil	935	18.89
Gas	3,371	76.95
Total	4,306	95.84

Information on multiple completions is not available from Panhandle's records, but the number of such is insignificant.

As of September 30, 2007, Panhandle owned 345,695 gross developed mineral acres and 42,375 net developed mineral acres. Panhandle has also leased from others 174,579 gross developed acres, which contain 17,487 net developed acres.

UNDEVELOPED ACREAGE

As of September 30, 2007, Panhandle owned 1,253,775 gross and 199,306 net undeveloped mineral acres, and leases on 19,643 gross and 3,250 net acres.

DRILLING ACTIVITY

The following net productive development and exploratory wells and net dry development and exploratory wells in which the Company had a fractional royalty or working interest were drilled and completed during the fiscal years indicated. Also shown are the net wells purchased during these periods.

Development Wells	Net Productive Wells	Net Dry Wells
Fiscal year ended September 30, 2005	5.485356	0.142047
Fiscal year ended September 30, 2006	5.477069	0.139168
Fiscal year ended September 30, 2007	6.215883	0.025393
Exploratory Wells		
Fiscal year ended September 30, 2005	0.584992	0.131758
Fiscal year ended September 30, 2006	0.747225	0.159593
Fiscal year ended September 30, 2007	1.539561	0.137873
Purchased Wells		
Fiscal year ended September 30, 2005	1.660737	0
Fiscal year ended September 30, 2006	0	0
Fiscal year ended September 30, 2007	0	0

PRESENT ACTIVITIES

The following table sets forth the gross and net oil and gas wells drilling or testing as of September 30, 2007, in which Panhandle owns a royalty or working interest. These wells are not yet producing.

	Gross Wells	Net Wells
Oil	2	0.01000
Gas	42	1.68387

OTHER FACILITIES

The Company leases 9,944 square feet of office space in Oklahoma City, OK. The lease obligation ends in 2009.

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, contain, 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 after the date of this report which reflect the occurrence of unanticipated events.

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 consolidated results for 2008 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 heavily 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 extremely 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, at times, has 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 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 estimated discounted future net cash flows from proved oil and natural gas reserves are determined based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows are also affected, in part, by the amount and timing of oil 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 for use 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 or Wood Oil as of 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, 2007.

PART II

ITEM 5 MARKET FOR REGISTRANTS' COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Company's Class A Common Stock ("Common Stock") is listed on the American Stock Exchange (symbol PHX). The following table sets forth the high and low trade prices of the Common Stock during the periods indicated (all share and per share amounts are adjusted for the 2-for-1 stock split, effective on January 9, 2006):

Quarter Ended	High	Low
December 31, 2005	$ 22.00	$ 14.23
March 31, 2006	$ 23.50	$ 17.05
June 30, 2006	$ 22.50	$ 17.00
September 30, 2006	$ 19.78	$ 16.68
December 31, 2006	$ 19.75	$ 17.25
March 31, 2007	$ 20.68	$ 17.80
June 30, 2007	$ 28.80	$ 19.70
September 30, 2007	$ 28.60	$ 20.18

As of December 4, 2007, there were 1,826 holders of record of Panhandle's Class A Common Stock and approximately 3,000 beneficial owners.

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 2005	$ 0.025
March 2006	$ 0.08
June 2006	$ 0.04
September 2006	$ 0.04
December 2006	$ 0.04
March 2007	$ 0.07
June 2007	$ 0.07
September 2007	$ 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 current line of credit loan agreement also contains a provision limiting the paying or declaring of a cash dividend to 20% of net cash flow provided by operating activities from the Consolidated Statement of Cash Flows of the preceding 12-month period. See Note 4 to the consolidated financial statements contained herein at "Item 8 - Financial Statements," for a further discussion of the loan agreement.

ITEM 6 SELECTED FINANCIAL DATA

The following table summarizes consolidated financial data of the Company and should be read in conjunction with the "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements of the Company, including the Notes thereto, included elsewhere in this report.

	Year Ended September 30,				
	2007	2006	2005	2004	2003
Revenues					
Oil & Gas Sales	$ 37,449,174	$ 36,008,527	$ 30,242,210	$ 23,578,615	$ 22,098,198
Lease Bonuses	208,625	410,984	2,214,992	115,938	72,765
Interest & Other	1,471,112	1,066,169	1,140,973	912,056	285,075
	$ 39,128,911	$ 37,485,680	$ 33,598,175	$ 24,606,609	$ 22,456,038
Costs and Expenses					
Lease Oper. Exp. & Prod. Taxes	$ 6,057,456	$ 5,262,834	$ 4,802,595	$ 4,098,124	$ 4,013,572
Exploration Costs (A)	1,050,069	222,892	784,741	236,939	469,224
Depr. Depl. Amortization	15,291,625	10,142,367	7,506,571	6,115,500	5,783,457
Provision for Impairment	3,761,832	3,009,953	232,295	841,687	692,220
Loss on Sale of Assets	254,395	119,282	291,452	-	-
Gen. & Administrative	3,877,492	3,335,899	4,545,208	3,033,437	2,666,177
Interest Expense	133,578	232,234	359,527	488,097	699,266
	$ 30,426,447	$ 22,325,461	$ 18,522,389	$ 14,813,784	$ 14,323,916
Income Before Provision For Income Taxes	$ 8,702,464	$ 15,160,219	$ 15,075,786	$ 9,792,825	$ 8,132,122
Cumulative effect of accounting changes, net of taxes of $28,500 (B)	-	-	-	-	46,500
Provision for Income Taxes	2,359,000	4,586,000	4,591,000	3,063,000	2,217,000
Net Income	$ 6,343,464	$ 10,574,219	$ 10,484,786	$ 6,729,825	$ 5,961,622
Basic Earnings per share	$ 0.75	$ 1.25	$ 1.25	$ 0.80	$ 0.71
Diluted Earnings per share	$ 0.75	$ 1.25	$ 1.24	$ 0.80	$ 0.71
Dividends Declared per share	$ 0.25	$ 0.185	$ 0.125	$ 0.09	$ 0.07
Weighted Average Shares Outstanding (C)					
Basic	8,499,233	8,479,406	8,390,280	8,357,566	8,325,488
Diluted	8,499,233	8,479,406	8,450,238	8,457,602	8,414,852
Net Cash Provided by (used in):					
Operating Activities	$ 28,106,500	$ 23,470,145	$ 17,909,249	$ 15,583,362	$ 13,487,890
Investing Activities	$ (26,940,679)	$ (21,118,606)	$ (10,514,096)	$ (10,631,869)	$ (9,200,810)
Financing Activities	$ (610,814)	$ (3,556,019)	$ (6,398,663)	$ (4,902,156)	$ (3,936,910)
Total Assets	$ 78,539,797	$ 70,949,242	$ 61,241,692	$ 54,186,362	$ 49,402,534
Long-Term Debt	$ 4,661,471	$ 1,166,649	$ 3,166,653	$ 8,516,657	$ 12,666,661
Shareholders' Equity	$ 53,681,371	$ 49,065,697	$ 38,635,350	$ 28,700,515	$ 22,527,685

All share and per share amounts are adjusted for the effects of 2-for-1 stock splits, effective in January 2006 and in April 2004.

(A) The Company uses the successful efforts method of accounting for its oil and gas activities.

(B) Represents the income effect of the adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations* on October 1, 2003. See Note 1: Summary of Significant Accounting Policies of Notes to the Consolidated Financial Statements herein.

(C) Weighted average shares outstanding for basic and diluted earnings per share are the same in fiscal year 2007 and 2006 due to the October 2005 amendment to the Deferred Compensation Plan for Non-Employee Directors.

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

RESULTS OF OPERATIONS

General

The Company's principal line of business is the production and sale of oil and natural gas. Results of operations are dependent upon the quantity of production and the price obtained for such production. Prices received by the Company for the sale of its oil and natural gas have fluctuated significantly from period to period. These fluctuations affect the Company's ability to maintain or increase its production from existing oil and gas properties and to explore, develop or acquire new properties. Capital expenditures, which increased significantly in 2006 and 2007, are expected to again increase in 2008 which should translate into increased production volumes for the Company going forward.

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

	For the Year Ended September 30,				
	2007	Percent Incr or (Decr)	2006	Percent Incr or (Decr)	2005
Production:					
Oil (Bbls)	107,344	11%	97,139	(4%)	101,581
Gas (Mcf)	5,147,343	20%	4,299,142	7%	4,011,226
Mcfe	5,791,407	19%	4,881,976	6%	4,620,712
Average Sales Price:					
Oil (per Bbl)	$ 62.81	(1%)	$ 63.44	24%	$ 51.30
Gas (per Mcf)	$ 5.97	(14%)	$ 6.94	11%	$ 6.24
Mcfe	$ 6.47	(12%)	$ 7.38	13%	$ 6.54

2007 Compared to 2006

Overview

The Company recorded net income of $6,343,464 in 2007, compared to net income of $10,574,219 in 2006. Total revenues were slightly higher in 2007 as a result of increased oil and gas sales generated by increased sales volumes of oil and natural gas in 2007 as compared to 2006. However, the revenue increases were more than offset by substantial increases in exploration costs, depreciation, depletion and amortization and provision for impairment expense in 2007 as compared to 2006.

Revenues

Total revenues increased $1,643,231 or 4% for 2007 as compared to 2006. The increase was the result of a $1,440,647 increase in oil and natural gas sales, a $765,316 increase in combined realized and unrealized gains on natural gas collar contracts and a $202,359 decrease in lease bonuses and rentals. Oil and natural gas sales increases were due to an overall 19% increase in oil and natural gas production, a 1% decrease in oil prices and a 14% decrease in natural gas prices. The production increases are the result of the Company's continued strategy of participating with higher interests in new wells, especially in the Dill City and Woodford Shale areas where significant production is now being received from several newly completed wells. All realized and unrealized gains from natural gas collar contracts in 2007 were a part of the revenue increase as no hedging of natural gas prices had been implemented previously by the Company. The decrease in lease bonuses and rentals is attributed to the Company's strategy of increasing its average working interest in wells by participating with larger portions of its mineral acreage as well proposals are received, thus leasing to third parties less. The table above outlines the Company's production and average sales prices for oil and natural gas for 2007 and 2006. High drilling activity continues in some key areas where the Company has significant mineral and leasehold acreage positions and as the Company continues its strategy to increase its working interest participation in new wells, 2008 budgeted drilling commitments have been increased to $42.5 million. In 2008, the Company again expects to more than replace the production decline of existing wells with new production from wells that come on line in 2008.

Production by quarter for 2007 was as follows:

First quarter	1,334,357 mcfe
Second quarter	1,305,041 mcfe
Third quarter	1,432,023 mcfe
Fourth quarter	1,719,986 mcfe

Realized and Unrealized Gains on Natural Gas Collar Contracts

As of September 30, 2007, the Company's fair value of derivative contracts (unrealized gain) was $106,916. The Company had no derivative contracts during 2006. The Company received cash payments (realized gains) in 2007 of $658,400 under the contracts.

Lease Operating Expenses and Production Taxes (LOE)

LOE increased $614,072 or 20% in 2007. The increase is a result of the increased number of larger ownership wells going on line in 2007 (new wells normally have higher operating costs the first several months of production), and the continuing increase in the overall number of wells in which the Company has an interest. LOE costs per mcfe of production were $.63 in both 2007 and 2006.

Production Taxes

Production taxes increased $180,550 or 8% in 2007. The increase is the result of the higher oil and gas revenues in 2007, as production taxes are paid as a percentage of these revenues.

Exploration Costs

Exploration costs increased $827,177 in 2007 as compared to 2006. This increase is principally the result of a $467,868 exploratory dry hole drilled in 2007 as compared to a $143,264 exploratory dry hole drilled in 2006. Since the Company utilizes the successful efforts method of accounting for oil and gas operations, only exploratory dry holes result in their costs being charged to exploration costs. Also,

the Company charges to exploration costs for leasehold deemed worthless or the lease term had expired. Such costs were higher in 2007 as compared to 2006 by $479,420.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased $5,149,258 or 51% in 2007 to $2.64 per mcfe as compared to $2.08 per mcfe in 2006. Reductions in the estimate of remaining reserves on several properties, large increases in drilling expenditures the last two years, due to the Company's participation with higher ownership interests in new wells and high initial production on these newly drilled wells resulted in this increase. On 34 of the Company's over 1,250 working interest wells, reserve evaluations were reduced by the Company's consulting engineer resulting in approximately $2 million of additional DD&A charges in 2007 as compared to 2006. DD&A on 16 significant new wells that began producing in 2007 accounted for another $1.3 million of the DD&A increase. The continued increase in drilling expenditures which has added significantly to the depreciable base of the Company's properties combined with the higher initial production received from these same properties (thus accelerating the depreciation taken) accounts for the remainder of the increase.

Provision for Impairment

The provision for impairment increased $751,879 in 2007 as compared to 2006. One large western Oklahoma field which was impaired by approximately $1.9 million in 2006 was again impaired in 2007 by approximately $2.0 million as production, and thus ultimate reserves, from the wells in this field has continued to decline at a faster rate than anticipated. The impairment of a Chaves County, New Mexico, field for approximately $402,000, a Winkler County, Texas, field for approximately $478,000 and a Beckham County, Oklahoma, field for approximately $214,000 comprise most of the remaining 2007 impairment provision.

Loss on Sale of Assets

Loss on sale of assets increased $135,113 in 2007 as compared to 2006. Several low performing properties in southeast Oklahoma were sold in 2007 at a loss of $221,998. In 2006, one property was sold at a loss of $94,275. Other insignificant sales accounted for the remainder in both 2007 and 2006.

General and Administrative Costs (G&A)

G&A costs increased $541,593 or 16% in 2007. Increases of approximately $290,000 of directors' expense, $147,000 of salary and benefit related costs, $76,000 of consulting costs and $20,000 of legal costs account for the majority of the overall increase in G&A costs. Of the directors' expense increase, approximately $288,000 relates to an amendment to the Directors' Deferred Compensation Plan (the Plan) that was effective October 19, 2005. The Plan was amended so that on retirement, termination or death of the director or on a change in control of the Company, the shares accrued under the Plan will be issued to the director. No shares are issued to a director until the occurrence of one of these events. This amendment removed the "conversion to cash" option previously available under the Plan, thus eliminating the requirement (after October 19, 2005) that the deferred compensation accounts be adjusted for changes in the market value of the Company's common stock. The adjustment of the deferred compensation liability to market value of the shares at the closing price on October 19, 2005, resulted in a credit to G&A of approximately $288,000. After the October 19, 2005, adjustment, the deferred compensation liability was reclassified to stockholders' equity.

Interest Expense

Interest expense decreased in 2007 due to lower outstanding debt balances.

Provision for Income Taxes

Provision for income taxes decreased $2,227,000 in 2007 as compared to 2006 as a result of income before provision for income tax decreasing by $6,457,755. The Company utilizes excess percentage depletion to reduce its effective tax rate from the federal statutory rate. The effective tax rate was 27.1% for 2007 and 30.3% for 2006.

Liquidity and Capital Resources

At September 30, 2007, the Company had positive working capital of $7,191,111 as compared to $4,997,714 at September 30, 2006. Items with positive effects on working capital include increase in cash of $555,007, increase in oil and gas sales receivable of $1,631,627 and decrease in long-term debt due within one year of $2,000,004. Items that had a negative effect include a decrease in income tax and other receivables of $1,772,987 and an increase in accounts payable of $209,079. Cash and oil and gas sales receivable have increased as a result of an overall increase in revenue. The short-term portion of the long-term debt was eliminated as a term loan was paid off on September 1, 2007. The decrease in income tax and other receivables mainly relates to the Company's receipt of a $1 million income tax refund in 2007 and alternative minimum tax due for 2007 of $503,000. Accounts payable increased due to the increased participation in drilling new wells. Capital expenditures increased and will continue to increase as the Company implements its strategy of increasing the average working interest in new wells drilled, the drilling of oil and natural gas wells continues to increase in number and costs of drilling and equipping new wells continues to increase.

Cash flow from operating activities increased 16% over last year. Additions to properties and equipment for oil and gas activities for 2007 amounted to $28,112,522, as compared to $22,624,040 for 2006. Management currently expects capital commitments for oil and gas activities to be approximately $44.7 million for 2008. This includes expected well drilling and equipment costs of $42.5 million and $2.2 for both leasehold acreage purchases and workover expenses on existing wells. The $42.5 million commitment budget is expected to include expenditures of approximately $25 million on gas resource drilling projects principally in southeast Oklahoma and Arkansas and $17 million on drilling projects in western Oklahoma. Any acquisition of oil and gas properties would further increase capital expenditures. As the Company does not operate any of the wells in which it participates, it is difficult to predict which or how many wells will actually be drilled in fiscal 2008.

The Company has historically funded capital expenditures, overhead costs and dividend payments from operating cash flow and has utilized, at times, its bank revolving line-of-credit facility to help fund these expenditures. The $50 million facility currently has a $10 million borrowing base which could probably be expanded up to the $50 million maximum, if needed. The borrowing base is set by the Company to minimize the fee on the unused portion of the borrowing base. Based on expected natural gas production volumes and prices for fiscal 2008, the expected capital expenditure level discussed above, and no meaningful acquisitions of oil and gas properties, borrowings of $10-15 million in fiscal 2008 are possible. Changes in production volumes or pricing or an acceleration or slowing down of the development in the gas resource projects would materially affect anticipated borrowings.

Contractual Obligations

In October 2006, the Company arranged a new credit facility with Bank of Oklahoma (BOK) replacing its credit facility with BancFirst of Oklahoma City, Oklahoma. The BOK Agreement consisted of a term loan in the amount of $2,500,000 and a revolving loan in the amount of $50,000,000 which is subject to a semi-annual borrowing base determination. The current borrowing base under the BOK Agreement is $10,000,000. The term loan matured on September 1, 2007, and was paid off, and the revolving loan matures on October 31, 2009. Monthly payments, began December 1, 2006, on the term

loan and were $250,000, plus accrued interest. Borrowings under the revolving loan are due at maturity. The term loan's interest rate was 30 day LIBOR plus .75%. The revolving loan bears interest at the national prime rate minus from 1.375% to .75%, or 30 day LIBOR plus from 1.375% to 2.0%. The interest rate charged will be based on the percent of the value advanced of the calculated loan value of Panhandle's oil and gas reserves. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the loan value of Panhandle's oil and 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 Panhandle's oil and 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, 2007, the Company was in compliance with these covenants.

The table below summarizes the Company's contractual obligations under the BOK facility, as of September 30, 2007:

	Payments Due By Period				
Contractual Obligations	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$4,661,471	$ -	$4,661,471	$ -	$ -

Hedging

Effective January 1, 2007, the Company entered into the following three natural gas collar contracts.

First Contract:

Production volume covered	30,000 mmbtu/month
January through December of 2007	Floor of $6.00 and a ceiling of $9.20

Second Contract:

Production volume covered	40,000 mmbtu/month
January through December of 2007	Floor of $6.00 and a ceiling of $9.20

Third Contract:

Production volume covered	30,000 mmbtu/month
January through December of 2007	Floor of $6.00 and a ceiling of $10.20

Subsequent to year end, in November 2007, the Company entered into the following natural gas collar contracts.

First Contract:	
Production volume covered	40,000 mmbtu/month
January through March of 2008	Floor of $6.60 and a ceiling of $8.85
April through September of 2008	Floor of $6.20 and a ceiling of $8.15
October through December of 2008	Floor of $6.50 and a ceiling of $8.90
Second Contract:	
Production volume covered	40,000 mmbtu/month
January through March of 2008	Floor of $6.60 and a ceiling of $9.10
April through September of 2008	Floor of $6.40 and a ceiling of $8.60
October through December of 2008	Floor of $6.90 and a ceiling of $9.15
Third Contract:	
Production volume covered	40,000 mmbtu/month
January through March of 2008	Floor of $6.55 and a ceiling of $8.80
April through September of 2008	Floor of $6.15 and a ceiling of $8.05
October through December of 2008	Floor of $6.55 and a ceiling of $8.75

The derivative instruments will settle based on the prices above which are basis adjusted and tied to certain pipelines in Oklahoma.

2006 Compared to 2005

Overview

The Company recorded net income of $10,574,219 in 2006, compared to net income of $10,484,786 in 2005. Total revenues were higher in 2006 as a result of increased oil and gas sales generated by increases in the average sales prices of oil and natural gas and increased sales volumes of natural gas in 2006 as compared to 2005. The revenue increases were offset by substantial increases in depreciation, depletion and amortization and provision for impairment expense in 2006 as compared to 2005.

Revenues

Total revenues increased $3,887,505 or 12% for 2006 as compared to 2005. The increase was the result of a $5,766,317 increase in oil and natural gas sales revenues offset by a decline in lease bonus revenues of $1,804,008. The increase in oil and gas sales revenues resulted from a 24% and 11% increase in the average sales price for oil and natural gas, respectively, and a 7% increase in gas sales volumes. The decrease in lease bonus revenue in 2006 is a result of the Company leasing all of its non-producing mineral acreage in Arkansas in 2005. The total lease bonus, net of associated basis, was $1,879,467, as compared to normal leasing activity in 2006. The table above outlines the Company's production and average sales prices for oil and natural gas for 2006 and 2005.

The continuing increase in drilling expenditures and the Company's stated goal of increasing its working interest percentage in new wells drilled is expected to result in continuing increased production volumes for gas in 2007, as compared to 2006. The Company has announced a significant increase, to $31.5 million, in its drilling budget for 2007. Drilling continues to be concentrated on natural gas prospects and new wells expected to be put on line in 2007 should continue to more than replace the decline of existing well production.

Production by quarter for 2006 was as follows:

First quarter	1,196,923 mcfe
Second quarter	1,173,313 mcfe
Third quarter	1,134,814 mcfe
Fourth quarter	1,376,926 mcfe

Lease Operating Expenses and Production Taxes (LOE)

LOE increased $175,499 or 6% in 2006. The increase is a result of new larger percentage ownership wells going on line in 2006, as new wells normally have higher operating costs the first several months of production, the continuing increase in the number of wells in which the Company has an interest and general oilfield price increases. In addition water disposal costs on one new well have been disproportionately high. LOE costs per mcfe of production were $.63 in 2006 as compared to $.62 in 2005.

Production Taxes

Production taxes increased $284,740 or 15% in 2006. The increase is the result of the higher oil and gas revenues in 2006, as production taxes are paid as a percentage of these revenues.

Exploration Costs

Exploration costs decreased $561,849 in 2006 as compared to 2005. This decrease is principally the result of three higher cost exploratory dry holes drilled in 2005 as compared to only one in 2006. Since the Company utilizes the successful efforts method of accounting for oil and gas operations, only exploratory dry holes result in their costs being charged to exploration costs. Also, the Company's charge to exploration costs for leasehold deemed worthless or the lease term had expired was higher in 2005.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased $2,635,796 or 35% in 2006. The increase is a result of higher costs in 2006 on new wells as general oilfield price increases have been substantial the last two years. These higher costs then must be depreciated. In addition, projected remaining production volumes were reduced on some wells, which then increases current DD&A costs. Further, high initial production rates and the inordinate amount of certain wells total estimated reserves being produced rapidly causes DD&A to be heavily weighted to the front end of these wells lives.

Provision for Impairment

The provision for impairment increased $2,777,658 in 2006 as compared to 2005. The impairment provision in 2005 benefited from higher natural gas prices (as of September 30, 2005) used in the fair value calculations as compared to substantially lower prices used in the 2006 calculation. Natural gas prices declined dramatically during the fourth fiscal quarter of 2006, and were at a low point for fiscal 2006 at September 30. Market price for natural gas affects the economic evaluation of properties and the potential impairment calculation. The 2006 provision was principally the result of one 27 well field in which the more recent wells drilled were not as good as earlier well results. The last well drilled in the field, which was a large interest well (25%), resulted in a poor well and caused the entire field to be in an impaired status. This field's carrying value was impaired by approximately $1.9 million. An adjacent one well field also incurred a $.5 million impairment in 2006.

Loss on Sale of Assets

Loss on sale of assets decreased $172,170 in 2006 as compared to 2005. Several low performing properties were sold in 2005 at a loss, with one group of wells sold at a loss of approximately $200,000. In 2006, one property was sold at a loss of $94,275, and other insignificant sales accounted for the remaining $25,007.

General and Administrative Costs (G&A)

G&A costs decreased $1,209,309 or 27% in 2006. The decrease is the result of an amendment to the Directors' Deferred Compensation Plan (the Plan). Effective October 19, 2005, the Plan was amended so that on retirement, termination or death of the director, or on a change in control of the Company, the shares accrued under the Plan will be issued to the director. No shares are issued to a director until the occurrence of one of these events. This amendment removed the conversion to cash option available under the Plan, which eliminated the requirement to adjust the deferred compensation liability for changes in the market value of the Company's common stock after October 19, 2005. The adjustment of the liability to market value of the shares at the closing price on October 19, 2005, resulted in a credit to G&A of approximately $288,000 as compared to a charge of approximately $990,000 in 2005. In addition, the deferred compensation liability after the October 19, 2005, adjustment was reclassified to stockholders' equity.

Interest Expense

Interest expense decreased in 2006 due to lower outstanding debt balances.

Provision for Income Taxes

The 2006 provision for income taxes was basically flat as compared to 2005, as income before provision for income tax increased only $84,433. The Company utilizes excess percentage depletion to reduce its effective tax rate from the federal statutory rate. The effective tax rate was 30.3% for 2006 and 30.5% for 2005.

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. Generally, accounting rules do not involve a selection among alternatives, but involve a selection of the appropriate policies for applying the basic principles. Interpretation of the existing rules must be done 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, impairment of assets, oil and gas sales revenue accruals and tax accruals. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known. The oil and gas sales revenue accrual is particularly subject to estimates due to the Company's status as a non-operator on all of its properties. Production information obtained from well operators is substantially delayed. This causes the estimation of recent production, used in the oil and gas revenue accrual, to be subject to some variations.

Oil and Gas Reserves

Of these judgments and estimates, management considers the estimation of crude oil and natural gas reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as DD&A and impairment calculations. Changes in crude oil and natural gas reserve estimates affect the Company's calculation of depreciation, depletion and amortization, provision for abandonment and assessment of the need for asset impairments. On an annual basis, with a limited scope semi-annual update, the Company's consulting engineer (the Company employed a new consulting engineer beginning with the March 31, 2007, semi-annual update), with assistance from Company geologists, 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. As required by the guidelines and definitions established by the SEC, these estimates are based on current crude oil and natural gas pricing. Crude oil and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Projected future crude oil and natural gas pricing assumptions are used by management to prepare estimates of crude oil and natural gas reserves used in formulating management's overall operating decisions in the exploration and production segment.

Hedging

The Company periodically utilizes commodity price instruments, costless collars, to reduce its exposure to unfavorable changes in natural gas prices. Volumes under such contracts are a portion of expected production. The Company's collars contain a fixed floor price and a fixed ceiling price. If market prices exceed the ceiling price or fall below the floor, then the Company will receive the difference between the floor and market price or pay the difference between the ceiling and market price. If market prices are between the ceiling and the floor, then no payments or receipts related to the collars are required.

The Company accounts for its derivative contracts under Financial Accounting Standards Board Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS No. 133). Under the provision of SFAS No. 133, the Company is required to recognize all derivative instruments as either assets or liabilities in the consolidated 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 of SFAS No. 133, 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 currently in 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. Amounts recorded in unrealized gains (losses) on derivative activities do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts that are not entitled to receive hedge accounting treatment.

Successful Efforts Method of Accounting

The Company has elected to utilize the successful efforts method of accounting for its oil and 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 developmental dry holes are capitalized and amortized by property using the unit-of-production method as oil and gas is produced. This accounting method may yield significantly different operating results than the full cost method.

Impairment of Assets

All long-lived assets, principally oil and gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than its 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 and gas, future production costs, estimates of future oil and gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to oil and gas reserves. 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.

Oil and Gas Sales Revenue Accrual

The Company does not operate any of its oil and gas properties, and it primarily holds small interests in approximately 4,300 wells. Thus, obtaining timely production data from the well operators is extremely difficult. This requires the Company to utilize past production receipts and estimated sales price information to estimate its oil and gas sales revenue accrual at the end of each quarterly period. The oil and gas accrual can be impacted by many variables, including initial high production rates of new wells and subsequent rapid decline rates of those wells and rapidly changing market prices for natural gas. This could lead to an over or under accrual of oil and gas sales at the end of any particular quarter. Based on past history, the 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. 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 laws, regulations and interpretations.

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 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

The Company's results of operations and operating cash flows can be significantly impacted by changes in market prices for oil and gas. Based on the Company's 2007 production, a $.10 per Mcf change in the price received for natural gas production would result in a corresponding $515,000 annual change in pre-tax operating cash flow. A $1.00 per barrel change in the price received for oil production would result in a corresponding $107,000 annual change in pre-tax operating cash flow. Cash flows could also be impacted, to a lesser extent, by changes in the market interest rates related to the Company's credit facilities. The revolving loan bears interest at the national prime rate minus from 1.375% to .75%, or 30 day LIBOR plus from 1.375% to 2.0%. At September 30, 2007, the Company had $4,661,471 outstanding under these facilities. A change of .5% in the prime rate or on LIBOR would result in a change to interest expense of $23,307.

The Company periodically utilizes certain commodity price instruments, costless collars, to reduce its exposure to unfavorable changes in natural gas prices. Volumes under such contracts are a portion of expected production. The Company's collars contain a fixed floor price and a fixed ceiling price. If market prices exceed the ceiling price or fall below the floor, then the Company will receive the difference between the floor and market price or pay the difference between the ceiling and market price. If market prices are between the ceiling and the floor, then no payments or receipts related to the collars are required.

The Company had not, through fiscal 2006, entered into derivative instruments to hedge the price risk on its oil and gas production. Beginning in fiscal year 2007, the Company has entered in costless collar arrangements intended to reduce the Company's exposure to short-term fluctuations in the price of natural gas. These arrangements cover only a portion of the Company's production and provide only partial price protection against declines in natural gas prices. These economic hedging arrangements may expose the Company to risk of financial loss and limit the benefit of future increases in prices. The derivative instruments will settle based on the prices below which are basis adjusted and tied to certain pipelines in Oklahoma.

Effective January 1, 2007, the Company entered into the following three natural gas collar contracts.

First Contract:	
Production volume covered	30,000 mmbtu/month
January through December of 2007	Floor of $6.00 and a ceiling of $9.20
Second Contract:	
Production volume covered	40,000 mmbtu/month
January through December of 2007	Floor of $6.00 and a ceiling of $9.20
Third Contract:	
Production volume covered	30,000 mmbtu/month
January through December of 2007	Floor of $6.00 and a ceiling of $10.20

Subsequent to year end, in November 2007, the Company entered into the following natural gas collar contracts.

First Contract:	
Production volume covered	40,000 mmbtu/month
January through March of 2008	Floor of $6.60 and a ceiling of $8.85
April through September of 2008	Floor of $6.20 and a ceiling of $8.15
October through December of 2008	Floor of $6.50 and a ceiling of $8.90
Second Contract:	
Production volume covered	40,000 mmbtu/month
January through March of 2008	Floor of $6.60 and a ceiling of $9.10
April through September of 2008	Floor of $6.40 and a ceiling of $8.60
October through December of 2008	Floor of $6.90 and a ceiling of $9.15
Third Contract:	
Production volume covered	40,000 mmbtu/month
January through March of 2008	Floor of $6.55 and a ceiling of $8.80
April through September of 2008	Floor of $6.15 and a ceiling of $8.05
October through December of 2008	Floor of $6.55 and a ceiling of $8.75

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 all of the documentation requirements necessary under SFAS No. 133 to permit these derivative contracts to be accounted for as cash flow hedges. The Company's fair value of derivative contracts was $106,916 as of September 30, 2007 (none as of September 30, 2006) resulting in net unrealized gains of $106,916 and realized gains of $658,400 in the year ended September 30, 2007.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Annual Report on Internal Control Over Financial Reporting

The 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, 2007. 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, 2007, the Company's internal control over financial reporting was effective based on those criteria.

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, 2007, 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 effectiveness of 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, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Panhandle Oil and Gas Inc. as of September 30, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2007, and our report dated December 10, 2007, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 10, 2007

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Panhandle Oil and Gas Inc. (the Company) as of September 30, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2007. 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 consolidated financial position of Panhandle Oil and Gas Inc. at September 30, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2007, in conformity with U.S. generally accepted accounting principles.

We have also 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, 2007, 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 10, 2007, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 10, 2007

Panhandle Oil and Gas Inc.
Consolidated Balance Sheets

	September 30, 2007	September 30, 2006
Assets		
Current Assets:		
Cash and cash equivalents	$ 989,360	$ 434,353
Oil and gas sales receivables	8,103,250	6,471,623
Fair value of derivative contracts	106,916	-
Refundable income taxes and other	112,882	1,889,636
Total current assets	9,312,408	8,795,612
Property and equipment at cost, based on successful efforts accounting:		
Producing oil and gas properties	125,634,251	103,129,158
Non-producing oil and gas properties	10,697,854	11,273,373
Furniture and fixtures	625,455	562,047
	136,957,560	114,964,578
Less accumulated depreciation, depletion, and amortization	68,424,645	53,654,385
Net properties and equipment	68,532,915	61,310,193
Investments	690,011	838,974
Other	4,463	4,463
Total assets	$ 78,539,797	$ 70,949,242

(Continued on next page)

See accompanying notes.

Panhandle Oil and Gas Inc.
Consolidated Balance Sheets

	September 30, 2007	September 30, 2006
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts payable	$ 1,773,255	$ 1,564,176
Accrued liabilities	348,042	233,718
Long-term debt due within one year	-	2,000,004
Total current liabilities	2,121,297	3,797,898
Long-term debt	4,661,471	1,166,649
Deferred income taxes	16,827,750	15,498,750
Asset retirement obligation and other noncurrent liabilities	1,247,908	1,420,248
Stockholders' equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized, 8,431,502 issued and outstanding (8,422,529 in 2006)	140,524	140,375
Capital in excess of par value	2,146,071	1,924,587
Deferred directors' compensation	1,358,778	1,202,569
Retained earnings	50,035,998	45,798,166
Total stockholders' equity	53,681,371	49,065,697
Total liabilities and stockholders' equity	$ 78,539,797	$ 70,949,242

See accompanying notes.

Panhandle Oil and Gas Inc.
Consolidated Statements of Income

	Year ended September 30,		
	2007	**2006**	**2005**
Revenues:			
Oil and gas sales	$ 37,449,174	$ 36,008,527	$ 30,242,210
Lease bonuses and rentals	208,625	410,984	2,214,992
Realized gains on gas collar contracts	658,400	-	-
Unrealized gains on gas collar contracts	106,916	-	-
Gain on sales and interest	322,405	529,804	745,800
Income from partnerships	383,391	536,365	395,173
	39,128,911	37,485,680	33,598,175
Costs and expenses:			
Lease operating expenses and production taxes	6,057,456	5,262,834	4,802,595
Exploration costs	1,050,069	222,892	784,741
Depreciation, depletion, and amortization	15,291,625	10,142,367	7,506,571
Provision for impairment	3,761,832	3,009,953	232,295
Loss on sale of assets	254,395	119,282	291,452
General and administrative	3,877,492	3,335,899	4,545,208
Interest expense	133,578	232,234	359,527
	30,426,447	22,325,461	18,522,389
Income before provision for income taxes	8,702,464	15,160,219	15,075,786
Provision for income taxes	2,359,000	4,586,000	4,591,000
Net Income	$ 6,343,464	$ 10,574,219	$ 10,484,786
Basic earnings per common share:			
Net income	$ 0.75	$ 1.25	$ 1.25
Diluted earnings per common share:			
Net income	$ 0.75	$ 1.25	$ 1.24

See accompanying notes.

Panhandle Oil and Gas Inc.
Consolidated Statements of Stockholders' Equity

	Common Stock Shares	Common Stock Amount	Capital in Excess of Par Value	Deferred Directors Compensation	Retained Earnings	Total
Balances at September 30, 2004	8,379,566	$ 139,660	$ 1,217,020	$ -	$ 27,343,835	$ 28,700,515
Issuance of common shares to ESOP	9,186	154	196,380	-	-	196,534
Issuance of common shares to directors for services	22,134	368	301,806	-	-	302,174
Dividends declared ($.125 per share)	-	-	-	-	(1,048,659)	(1,048,659)
Net Income	-	-	-	-	10,484,786	10,484,786
Balances at September 30, 2005	8,410,886	$ 140,182	$ 1,715,206	$ -	$ 36,779,962	$ 38,635,350
Issuance of common shares to ESOP	11,643	193	209,381	-	-	209,574
Increase in deferred directors compensation:						
Reclassification of liability	-	-	-	1,053,408	-	1,053,408
Charged to expense	-	-	-	149,161	-	149,161
Dividends declared ($.185 per share)	-	-	-	-	(1,556,015)	(1,556,015)
Net Income	-	-	-	-	10,574,219	10,574,219
Balances at September 30, 2006	8,422,529	$ 140,375	$ 1,924,587	$ 1,202,569	$ 45,798,166	$ 49,065,697
Issuance of common shares to ESOP	8,973	149	221,484	-	-	221,633
Issuance of common shares to directors for services	-	-	-	156,209	-	156,209
Dividends declared ($.25 per share)	-	-	-	-	(2,105,632)	(2,105,632)
Net Income	-	-	-	-	6,343,464	6,343,464
Balances at September 30, 2007	8,431,502	$ 140,524	$ 2,146,071	$ 1,358,778	$ 50,035,998	$ 53,681,371

See accompanying notes.

Panhandle Oil and Gas Inc.
Consolidated Statements of Cash Flows

	Year ended September 30,		
	2007	**2006**	**2005**
Operating Activities			
Net income	$ 6,343,464	$ 10,574,219	$ 10,484,786
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization, and impairment	19,053,457	13,152,320	7,738,866
Deferred income taxes	1,329,000	2,177,000	1,072,750
Lease bonus income	(45,954)	(95,892)	(2,133,337)
Exploration costs	1,050,069	222,892	784,741
Net loss (gain) on sale of assets	22,856	(415,951)	(365,288)
Equity in earnings of partnerships	(383,391)	(536,365)	(395,173)
Distributions received from partnerships	465,535	618,509	497,839
Common stock issued to ESOP	221,633	209,574	196,534
Common stock (unissued) to Directors' Deferred Compensation Plan	156,209	149,161	302,174
Cash provided (used) by changes in assets and liabilities:			
Oil and gas sales receivables	(1,631,627)	169,824	(1,678,455)
Fair value of derivative contracts	(106,916)	-	-
Refundable income taxes and other	1,635,853	(1,889,363)	218,375
Accounts payable	(118,012)	(21,361)	131,540
Accrued directors' deferred compensation	-	(281,897)	470,972
Accrued liabilities	(96,831)	37,144	(16,744)
Income taxes payable	211,155	(599,669)	599,669
Total adjustments	21,763,036	12,895,926	7,424,463
Net cash provided by operating activities	28,106,500	23,470,145	17,909,249
Investing Activities			
Capital expenditures, including dry hole costs	(27,785,431)	(21,738,745)	(14,998,876)
Proceeds from leasing of fee mineral acreage	188,417	493,652	2,304,383
Sale or (purchase) of investment	11,280	(282,000)	-
Proceeds from sale of assets	645,055	408,487	2,180,397
Net cash used in investing activities	$ (26,940,679)	$ (21,118,606)	$ (10,514,096)

(Continued on next page)

See accompanying notes.

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

	Year ended September 30,		
	2007	**2006**	**2005**
Financing Activities			
Borrowings under debt agreement	$ 18,046,213	$ -	$ 11,350,000
Payments of loan principal	(16,551,395)	(2,000,004)	(16,700,004)
Payments of dividends	(2,105,632)	(1,556,015)	(1,048,659)
Net cash used in financing activities	(610,814)	(3,556,019)	(6,398,663)
Increase (decrease) in cash and cash equivalents	555,007	(1,204,480)	996,490
Cash and cash equivalents at beginning of year	434,353	1,638,833	642,343
Cash and cash equivalents at end of year	$ 989,360	$ 434,353	$ 1,638,833
Supplemental Disclosures of Cash Flow Information			
Interest paid	$ 140,350	$ 219,898	$ 367,333
Income taxes paid, net of refunds received	$ (952,221)	$ 4,781,462	$ 2,668,870
Supplemental schedule of noncash investing and financing activities:			
Reclassification of deferred compensation liability as equity	$ -	$ 1,053,408	$ -
Additions and revisions, net, to asset retirement obligations	$ (213,759)	$ 141,158	$ 494,508
Properties and equipment change included in accounts payable	$ 327,091	$ 885,295	$ (257,239)

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 gas properties, principally involving the drilling of wells located on the Company's mineral acreage. Panhandle's mineral properties and other oil and gas interests are all located in the United States, primarily in Arkansas, Kansas, Oklahoma, New Mexico and Texas. The Company is not the operator of any wells. The majority of the Company's oil and gas production is from small interests in several thousand wells located principally in Oklahoma. Approximately 82% of oil and gas revenues are derived from the sale of natural gas. Substantially all the Company's oil and gas production is being 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 gas properties as a normal course of business.

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of Panhandle Oil and Gas Inc. and its wholly owned subsidiaries after elimination of all material intercompany transactions.

Investments and other assets for the prior year have been reclassified to conform to the current year presentation.

Use of Estimates

The 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 reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Of these judgments and estimates, management considers the estimation of crude oil and natural gas reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as DD&A and impairment calculations. Changes in crude oil and natural gas reserve estimates affect the Company's calculation of depreciation, depletion and amortization, provision for abandonment and assessment of the need for asset impairments. On an annual basis, with a limited scope semi-annual update, the Company's consulting engineer (the Company employed a new consulting engineer beginning with the March 31, 2007, semi-annual update), with assistance from Company geologists, 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. As required by the guidelines and definitions established by the SEC, these estimates are based on year-end crude oil and natural gas pricing. Crude oil and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Projected future crude oil and natural gas pricing assumptions are used by management to prepare estimates of crude oil and natural gas reserves used in formulating management's overall operating decisions in the exploration and production segment.

1. Summary of Significant Accounting Policies (continued)

The Company does not operate any of its oil and gas properties, and it primarily holds small interests in several thousand wells; however, in the last two years it has begun to take larger interests in several new wells drilled each year. Obtaining timely production data from the well operators is extremely difficult and in most cases substantially delayed. This causes the Company to utilize past production receipts and estimated sales price information to estimate its oil and gas sales revenue accrual at the end of each quarterly period. The oil and gas accrual can be impacted by many variables, including the initial high production rates and possible rapid decline rates of certain new wells and rapidly changing market prices for natural gas. The Company records an accrual to actual adjustment in each succeeding quarter.

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 Gas Sales and Gas Imbalances

The Company sells oil and natural gas to various customers, recognizing revenues as oil and gas is produced and sold. The Company uses the sales method of accounting for 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, 2007 and 2006, the Company had no material gas imbalances.

Charges for gathering and transportation are included in lease operating expenses and production taxes.

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 gas properties. Oil and natural gas sales are generally unsecured. The Company has not experienced any meaningful credit losses in prior years and is not aware of any uncollectible accounts at September 30, 2007 or 2006.

Oil and Gas Producing Activities

The Company follows the successful efforts method of accounting for oil and 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 gas mineral and leasehold costs are capitalized when incurred.

1. Summary of Significant Accounting Policies (continued)

Derivatives

In fiscal 2007, the Company began using derivative instruments to hedge the price risk on its gas production. The Company has entered in costless collar arrangements intended to reduce the Company's exposure to short-term fluctuations in the price of natural gas. Collar contracts set a minimum price, or floor, and a maximum price, or ceiling, and provide for payments to the Company if the reference price falls below the floor or require payments by the Company if the reference price rises above the ceiling. These arrangements cover only a portion of the Company's production and provide only partial price protection against declines in natural gas prices. These economic hedging arrangements may expose the Company to risk of financial loss and limit the benefit of future increases in prices. The Company accounts for its derivative activities under the guidance provided by SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" as amended and recognizes all of its derivatives as assets or liabilities in the balance sheet at fair value.

Effective January 1, 2007, the Company entered into the following three natural gas collar contracts.

First Contract:	
Production volume covered	30,000 mmbtu/month
January through December of 2007	Floor of $6.00 and a ceiling of $9.20
Second Contract:	
Production volume covered	40,000 mmbtu/month
January through December of 2007	Floor of $6.00 and a ceiling of $9.20
Third Contract:	
Production volume covered	30,000 mmbtu/month
January through December of 2007	Floor of $6.00 and a ceiling of $10.20

Subsequent to year end, in November 2007, the Company entered into the following natural gas collar contracts.

First Contract:	
Production volume covered	40,000 mmbtu/month
January through March of 2008	Floor of $6.60 and a ceiling of $8.85
April through September of 2008	Floor of $6.20 and a ceiling of $8.15
October through December of 2008	Floor of $6.50 and a ceiling of $8.90
Second Contract:	
Production volume covered	40,000 mmbtu/month
January through March of 2008	Floor of $6.60 and a ceiling of $9.10
April through September of 2008	Floor of $6.40 and a ceiling of $8.60
October through December of 2008	Floor of $6.90 and a ceiling of $9.15
Third Contract:	
Production volume covered	40,000 mmbtu/month
January through March of 2008	Floor of $6.55 and a ceiling of $8.80
April through September of 2008	Floor of $6.15 and a ceiling of $8.05
October through December of 2008	Floor of $6.55 and a ceiling of $8.75

1. Summary of Significant Accounting Policies (continued)

Depreciation, Depletion, Amortization, and Impairment

Depreciation, depletion, and amortization of the costs of producing oil and gas properties are generally computed using the units of production method primarily on a separate property basis using proved reserves as estimated annually by a 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 gas properties include non-producing minerals, which have a net book value of $5,351,731 at September 30, 2007, consisting of perpetual ownership of mineral interests in several states, with 81% of the acreage in Oklahoma, Texas and New Mexico. As mentioned these mineral rights are perpetual and have been accumulated over the 81 year life of the Company. There are approximately 212,000 acres of non-producing minerals in over 7,000 tracts owned by the Company. An average tract contains 30 acres and the average cost per acre is $39. Since inception, the Company has continually generated an interest in several thousand oil and 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, they do not expire (as do oil and gas leases), in many cases the same mineral acreage has seen several wells drilled over the span of several years and development of this acreage has been steady since the 1960's. Given the above, it was concluded that a longer term amortization was appropriate and that 33 years, based on past history and experience, was a conservative range. Also, based on the fact that the minerals consist of a large number of properties whose costs are not individually significant, and virtually all are in the Company's core operating areas, the minerals are being amortized on an aggregate basis.

In accordance with the provisions of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, 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 techniques considering expected future prices and costs and estimates of oil and gas quantities. The Company's oil and gas properties were reviewed for indicators of impairment on a field-by-field basis, resulting in the recognition of impairment provisions of $3,761,832, $3,009,953 and $232,295 respectively, for 2007, 2006 and 2005. The majority of the impairment recognized in 2005 relates to fields comprised of a small number of wells or single wells on which the Company does not expect sufficient future net cash flow to recover its carrying cost. The impairment in 2006 is mostly due to two adjacent western Oklahoma fields on which earlier drilled wells performed better than more recently drilled wells. These same fields experienced higher than expected overall production and reserve volume declines in 2007, resulting in further impairment on both fields in 2007. The impairments taken on these fields in 2006 and 2007 comprise approximately 66% of all impairment costs.

1. Summary of Significant Accounting Policies (continued)

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. The cost method is used to account for the Company's investment in one LLC where the Company holds an interest of less than one percent.

Asset Retirement Obligations

The Company owns 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. These expenditures are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). The Company does not have any assets restricted for the purpose of settling the plugging liabilities.

The following table shows the activity for the year ended September 30, 2007, relating to the Company's retirement obligation for plugging liability:

	Plugging Liability
Plugging Liability as of September 30, 2006	$1,374,294
Accretion of Discount	87,373
New Wells Placed on Production	73,257
Revisions in Estimates (A)	(287,016)
Plugging Liability as of September 30, 2007	$1,247,908

(A) Higher oil and gas prices at September 30, 2007, compared to September 30, 2006, increased the lives of the Company's wells and decreased the discounted amount of the plugging liability as of September 30, 2007.

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 these environmental laws will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future events. 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 to the extent available at reasonable cost, pollution control coverage. However, all risks are not insured due to the availability and cost of insurance.

1. Summary of Significant Accounting Policies (continued)

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, 2007 and 2006, there were no such costs accrued.

Earnings Per Share of Common Stock

Basic earnings per share (EPS) is calculated using net income divided by the weighted average of common shares outstanding (including unissued, vested directors' shares after October 19, 2005 - see Note 8) during the year. Diluted EPS is similar to basic EPS except that the weighted average common shares outstanding is increased (for periods prior to October 19, 2005) to include the number of additional common shares that would have been outstanding if the dilutive potential common shares had been issued. The treasury stock method is used to calculate dilutive shares, which reduces the gross number of dilutive shares (see Note 6).

Stock-based Compensation

The Company recognizes current compensation costs for its Outside Directors Deferred Compensation Plan (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. Effective October 19, 2005, the Plan was amended such 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. This amendment removed the conversion to cash option available under the Plan, resulting in reclassification to equity of the liability under the Plan. Effective October 1, 2005, the Company adopted Financial Accounting Standards Board (FASB) No. 123(R) "Share Based Payments." Due to the nature of the Company's equity based compensation, the adoption of the standard did not have a material effect on the Company's financial statements.

The Company applies SOP 93-6 in accounting for its non-leveraged Employee Stock Ownership Plan. Under SOP 93-6 the Company records as expense, the fair market value of the stock at the time of contribution.

Fair Values of Financial Instruments

The carrying amounts reported in the balance sheets for cash and cash equivalents, receivables, derivative contracts, income tax and other, 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 term loan and revolving line of credit being rates which are approximately equivalent to market rates for similar type debt based on the Company's credit worthiness.

1. Summary of Significant Accounting Policies (continued)

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. 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.

New Accounting Pronouncements

In June 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement 109," which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FAS 109, "Accounting for Income Taxes." FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 is effective for fiscal years beginning after December 15, 2006, which will be our fiscal year beginning October 1, 2007. The adoption of this statement is not expected to have a material impact on the Company's financial position or results of operations or cash flows.

On September 13, 2006, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin No. 108 ("SAB 108"), which provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB 108 was effective for the Company in fiscal year 2007. The adoption of this statement did not have a material impact on the Company's financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company is still assessing the impact of this statement, but the adoption of this statement is not expected to have a material effect on the Company's financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of this statement is not expected to have a material effect on the Company's financial position, results of operations or cash flows.

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 consolidated 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 2009. Future minimum rental payments under the terms of the lease are $163,259 in 2008 and $95,234 in 2009. Total rent expense incurred by the Company was $147,849 in 2007, $153,164 in 2006 and $158,203 in 2005.

3. Income Taxes

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

	2007	2006	2005
Current:			
Federal	$1,000,000	$2,351,000	$3,488,250
State	30,000	58,000	30,000
	1,030,000	2,409,000	3,518,250
Deferred:			
Federal	1,083,000	1,928,000	1,004,750
State	246,000	249,000	68,000
	1,329,000	2,177,000	1,072,750
	$2,359,000	$4,586,000	$4,591,000

The difference between the provision for income taxes and the amount which would result from the application of the federal statutory rate to income before provision for income taxes is analyzed below:

	2007	2006	2005
Provision for income taxes at statutory rate	$ 2,958,838	$ 5,210,883	$ 5,178,799
Percentage depletion	(604,662)	(699,384)	(620,982)
State income taxes, net of federal benefit	272,580	361,680	63,700
State net operating loss carryforward benefit	(102,925)	(241,000)	-
Other	(164,831)	(46,179)	(30,517)
	$ 2,359,000	$ 4,586,000	$ 4,591,000

3. Income Taxes (continued)

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:

	2007	2006
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$ 18,328,498	$ 16,538,959
Deferred tax assets:		
Alternative minimum tax credit carryforwards	503,000	-
State net operating loss carry forwards	471,815	368,890
Deferred directors compensation and other	525,933	671,319
	1,500,748	1,040,209
Net deferred tax liabilities	$ 16,827,750	$ 15,498,750

4. Long-term Debt

Long-term debt consisted of the following at September 30:

	2007	2006
4.56% term loan	$ -	$ 3,166,653
Revolving line of credit	4,661,471	-
Current maturities of long-term debt	-	2,000,004
	$ 4,661,471	$ 1,166,649

In October 2006, the Company refinanced its credit facility with BancFirst of Oklahoma City, Oklahoma (Bancfirst) with a new credit facility with Bank of Oklahoma (BOK). The BOK Agreement consisted of a term loan in the amount of $2,500,000 and a revolving loan in the amount of $50,000,000 which is subject to a semi-annual borrowing base determination. The current borrowing base under the BOK Agreement is $10,000,000. The term loan matured on September 1, 2007, and the revolving loan matures on October 31, 2009. Borrowings under the revolving loan are due at maturity. The revolving loan bears interest at the national prime rate minus from 1.375% to .75%, or 30 day LIBOR plus from 1.375% to 2.0% (effective rate of 6.5% as of September 30, 2007). The interest rate charged will be based on the percent of the value advanced of the calculated loan value of Panhandle's oil and gas reserves. The interest rate spread from LIBOR or prime increases or decreases as a larger percent of the loan value of Panhandle's oil and gas properties is advanced.

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 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

4. Long-term Debt (continued)

of treasury stock, and require the Company to maintain certain financial ratios. At September 30, 2007, the Company was in compliance with the covenants of the BOK agreement.

The amounts of required principal payments under the BOK agreement for the next five years, as of September 30, 2007, are as follows:

2008	$ -
2009	$ -
2010	$ 4,661,471
2011	$ -
2012	$ -

5. Shareholders' Equity

On December 13, 2005, the Company's Board of Directors declared a 2-for-1 stock split of the outstanding Class A Common Stock. The Class A Common Stock split was effected in the form of a stock dividend, distributed on January 9, 2006, to stockholders of record on December 29, 2005.

On December 12, 2006, the Company's Board of Directors approved a proposal to amend the Company's Articles of Incorporation to increase the number of authorized shares of Class A Common Stock from 12,000,000 shares to 24,000,000 shares with no change to the par value of $.01666 per share. On March 8, 2007, this proposal was put forth to a vote of the shareholders, for which a majority of the shareholders voted in favor of the proposal, causing this proposal to become effective on such date.

All agreements concerning Common Stock of the Company, including the Company's Employee Stock Ownership Plan and the Company's commitment under the Deferred Compensation Plan for Non-Employee Directors, provide for the issuance or commitment, respectively, of additional shares of the Company's stock due to the declaration of a stock split. All references to number of shares, per share, and authorized share information in the accompanying consolidated financial statements have been adjusted to reflect the stock split distributed to stockholders on January 9, 2006, and to reflect the increase in authorized shares approved on March 8, 2007, at the Annual Meeting of the Stockholders of the Company.

6. Earnings Per Share

The following table sets forth the computation of basic and diluted earnings per share. The Company's diluted earnings per share calculation in 2005 takes into account certain shares that may be issued under the Non-Employee Directors' Deferred Compensation Plan (see Note 8).

	Year ended September 30,		
	2007	2006	2005
Numerator for primary and diluted earnings per share:			
Net income	$ 6,343,464	$ 10,574,219	$ 10,484,786
Denominator:			
For basic earnings per share - weighted average shares (including for 2007 and 2006, unissued vested directors' shares of 76,679 and 68,488)	8,499,233	8,479,406	8,390,280
Effect of potential diluted shares:			
Directors' deferred compensation shares	*	*	59,958
Denominator for diluted earnings per share - adjusted weighted average shares and potential shares	8,499,233	8,479,406	8,450,238

* Not applicable - see Note 8.

The weighted average shares outstanding, potentially dilutive shares, and earnings per share for 2005 have been restated to affect the 2-for-1 stock splits discussed in Note 5.

7. Employee Stock Ownership Plan

The Company has an employee stock ownership plan that covers all employees and is established to provide such employees with a retirement benefit. These benefits become fully vested after three years of employment. Contributions to the plan are at the discretion of the Board of Directors and can be made in cash (none in 2007, 2006 or 2005) or the Company's common stock. For contributions of common stock, the Company records as expense, the fair market value of the stock at the time of contribution. The 220,983 shares of the Company's common stock held by the plan as of September 30, 2007, are allocated to individual participant accounts, are included in the weighted average shares outstanding for purposes of earnings per share computations and receive dividends which are credited to the individual accounts. Contributions to the plan consisted of:

Year	Shares	Amount
2007	8,973	$221,781
2006	11,643	$209,700
2005	9,186	$196,842

8. Deferred Compensation Plan for Directors

Effective November 1, 1994, the Company formed the Panhandle Deferred Compensation Plan for Non-Employee Directors (the Plan). 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. Because the original Plan contained an option allowing the directors to convert the shares to cash upon separation from the Company, the liability was adjusted for subsequent changes in market value of the shares. Upon retirement, termination or death of the director or upon change in control of the Company, the shares accrued under the Plan would have been either issued to the director or converted to cash, at the director's discretion, for the fair market value of the shares on the conversion date, as defined by the Plan. As of September 30, 2007, 78,398 shares (70,521 shares at September 30, 2006) are included in the Plan. Effective October 19, 2005, the Plan was amended such 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. This amendment removed the conversion to cash option available under the Plan, which resulted in reclassification to stockholders' equity of the deferred shares outstanding under the Plan. The deferred balance outstanding at September 30, 2007, under the Plan was $1,358,778 ($1,202,569 at September 30, 2006). $156,209, ($132,736) and $1,111,097 was charged (credited) to the Company's results of operations for the years ended September 30, 2007, 2006 and 2005, respectively, and is included in general and administrative expense in the accompanying income statement. The majority (89%) of the $1,111,097 charged to operations in 2005 was the result of the market prices of the Company's shares increasing from $8.60 per share at September 30, 2004, to $21.40 per share at September 30, 2005, thus requiring a charge to expense for the increase per share times the number of shares in the Plan during the year.

9. Information on Oil and Gas Producing Activities

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

During 2007, 2006 and 2005 approximately 20%, 14% and 17%, respectively, of the Company's total revenues were derived from sales through Chesapeake Operating, Inc. During 2007 and 2006 approximately 13% and 11%, respectively, of the Company's total revenues were derived from sales through JMA Energy Company.

9. Information on Oil and Gas Producing Activities (continued)

Aggregate Capitalized Costs

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

	2007	2006
Producing properties	$125,634,251	$103,129,158
Non-producing properties	10,697,854	11,273,373
	136,332,105	114,402,531
Accumulated depreciation, depletion and amortization	(67,962,465)	(53,239,322)
Net capitalized costs	$ 68,369,640	$ 61,163,209

Costs Incurred

During the reporting period, the Company incurred the following costs in oil and gas producing activities:

	2007	2006	2005 (1)
Property acquisition costs	$ 1,592,441	$ 983,159	$2,032,823
Exploration costs	4,604,380	2,719,068	907,385
Development costs	21,906,032	18,900,917	11,799,545
	$ 28,102,853	$ 22,603,144	$ 14,739,753

(1) Property acquisition costs include $900,000 related to the acquisition of proved properties.

10. Supplementary Information on Oil and Gas Reserves (Unaudited)

The following unaudited information regarding the Company's oil and natural gas reserves is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission (SEC) and SFAS No. 69, *Disclosures About Oil and Gas Producing Activities*.

Proved reserves are estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Because the Company's non-producing mineral and leasehold interests consist of various small interests in numerous tracts located primarily in Arkansas, Kansas, Oklahoma, New Mexico, and Texas, it is not economically feasible for the Company to provide estimates of all proved undeveloped reserves.

10. Supplementary Information on Oil and Gas Reserves (Unaudited) (continued)

The Company's net proved (including certain undeveloped reserves described above) oil and gas reserves, all of which are located in the United States, as of September 30, 2007, 2006 and 2005, have been estimated by Pinnacle Energy Services, LLC for 2007 and by Campbell and Associates for 2006 and 2005, 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, 2007, 2006 and 2005. 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 Quantities of Proved Oil and Gas Reserves

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

	Proved Reserves		
	Oil (Mbarrels)	**Gas (MMcf)**	
September 30, 2004	760	28,251	
Revisions of previous estimates	(60)	(3,122)	
Acquisitions	4	409	
Divestitures	(60)	(814)	
Extensions and discoveries	92	6,733	
Production	(102)	(4,011)	
September 30, 2005	634	27,446	
Revisions of previous estimates	(11)	(3,557)	(1)
Extensions and discoveries	49	11,279	
Production	(97)	(4,299)	
September 30, 2006	575	30,869	
Revisions of previous estimates	219	19	
Divestitures	(2)	(162)	
Extensions and discoveries	138	11,396	
Production	(107)	(5,116)	
September 30, 2007	823	37,006	

The prices used to calculate reserves and future cash flows from reserves for oil and natural gas, respectively, were as follows: September 30, 2007 - $78.93, $5.50; 2006 - $60.50, $3.49; 2005 - $64.18, $11.54.

(1) The large decrease in the natural gas price for 2006 resulted in a negative revision to gas reserves of 4,365 mmcf. Other revisions were a positive 808 mmcf.

10. Supplementary Information on Oil and Gas Reserves (Unaudited) (continued)

	Proved Developed Reserves		Proved Undeveloped Reserves	
	Oil (Mbarrels)	Gas (MMcf)	Oil (Mbarrels)	Gas (MMcf)
September 30, 2004	710	24,086	50	4,165
September 30, 2005	613	24,011	21	3,435
September 30, 2006	566	25,323	9	5,547
September 30, 2007	755	31,016	68	5,990

The above reserve numbers exclude approximately 1.2 - 1.6 Bcf of CO2 gas reserves for the years ended September 30, 2007, 2006, 2005 and 2004.

Standardized Measure of Discounted Future Net Cash Flows

Estimates of future cash flows from proved oil and gas reserves, based on current prices and costs, as of September 30 are shown in the following table. Estimated income taxes are calculated by applying the appropriate year-end tax rates to the estimated future pretax net cash flows less depreciation of the tax basis of properties and statutory depletion allowances. Prices used for determining future cash flows from oil and natural gas for the periods ended September 30, 2007, 2006 and 2005 were as follows: 2007 - $78.93, $5.50; 2006 - $60.50, $3.49; 2005 - $64.18, $11.54.

	2007	2006	2005
Future cash inflows	$ 270,149,990	$ 146,872,790	$ 358,380,000
Future production costs	61,736,120	34,045,630	55,406,990
Future development costs	9,429,990	7,101,523	5,458,591
Asset retirement obligation	1,247,908	1,374,294	1,144,299
Future net cash inflows before future income tax expenses	197,735,972	104,351,343	296,370,120
Future income tax expense	61,164,668	24,394,272	84,708,027
Future net cash flows	136,571,304	79,957,071	211,662,093
10% annual discount	59,542,180	28,765,504	78,040,774
Standardized measure of discounted future net cash flows	$ 77,029,124	$ 51,191,567	$ 133,621,319

10. Supplementary Information on Oil and Gas Reserves (Unaudited) (continued)

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

	2007	2006	2005
Beginning of year	$ 51,191,567	$133,621,319	$ 69,149,989
Changes resulting from:			
Sales of oil and gas, net of production costs	(31,391,718)	(30,745,693)	(25,439,615)
Net change in sales prices and production costs	43,499,178	(123,034,702)	96,847,355
Net change in future development costs	(1,511,175)	(1,053,612)	(1,142,715)
Net change in asset retirement obligation	74,315	(149,267)	(266,949)
Extensions and discoveries	35,711,533	23,822,148	43,200,477
Revisions of quantity estimates	4,401,619	(7,891,218)	(19,409,623)
Divestitures of reserves-in-place	(516,909)	-	(6,975,566)
Acquisition of reserves-in-place	-	-	2,585,268
Accretion of discount	6,772,402	19,006,216	9,698,899
Net change in income taxes	(22,707,174)	39,908,385	(28,601,833)
Change in timing and other, net	(8,494,516)	(2,292,009)	(6,024,368)
Net change	25,837,555	(82,429,752)	64,471,330
End of year	$ 77,029,122	$51,191,567	$133,621,319

11. Quarterly Results of Operations (Unaudited)

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

	Fiscal 2007			
	Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 8,931,895	$ 8,143,733	$ 10,988,346	$ 11,064,937
Income (loss) before provision for income taxes	2,876,937	(271,396)	4,176,578	1,920,345
Net income (loss)	1,983,493	(218,745)	2,904,078	1,674,638
Earnings (loss) per share	$ 0.23	$ (0.03)	$ 0.34	$ 0.20

	Fiscal 2006			
	Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$12,207,679	$ 8,728,506	$ 7,414,606	$ 9,134,889
Income before provision for income taxes	7,471,118	3,842,760	2,815,878	1,030,463
Net income	4,894,118	2,653,760	2,078,878	947,463
Earnings per share	$ 0.58	$ 0.31	$ 0.25	$ 0.11

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 Securities Exchange Act of 1934, that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including the Company's President/CEO and Vice President/CFO, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. The Company's disclosure controls and procedures have been designed to meet, and management believes that they do meet, reasonable assurance standards. Based on their evaluation as of the end of the fiscal period covered by this report, the President/CEO and Vice President/CFO have concluded that, subject to the limitations noted above, the Company's disclosure controls and procedures were effective to ensure that material information relating to the Company, including its consolidated subsidiary, is made known to them.

(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, 2007.

(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, 2007, or subsequent to the date the assessment was completed.

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 Consolidated 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)

(4) Instruments defining the rights of security holders (incorporated by reference to Certificate of Incorporation and By-Laws listed above)

(10) Amendment to Loan Agreement (incorporated by reference to Form 10-K dated September 30, 2003)

(10) Agreement indemnifying directors and officers (incorporated by reference to Form 10-K dated September 30, 1989, and Form 8-K dated June 15, 2007)

(21) Subsidiaries of the Registrant

(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

REPORTS ON FORM 8-K

Dated July 16, 2007, Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers

Dated August 16, 2007, Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers

Dated September 4, 2007, Item 1.01 Enters Into a Material Definitive Agreement

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 11, 2007

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

Date: December 11, 2007

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/ E. Chris Kauffman
E. Chris Kauffman, Chairman of Board

Date December 11, 2007

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

Date December 11, 2007

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

Date December 11, 2007

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

Date December 11, 2007

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

Date December 11, 2007

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

Date December 11, 2007

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

Date December 11, 2007

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