# PANHANDLE
## ROYALTY COMPANY

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2006 Annual Report

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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, "**Bcfe**" or "**Mcfe**" means natural gas stated on a Bcf or 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 2002-2006 refer to the Company's fiscal years ended September 30 each year. "**Minerals**" or "**mineral acres**" refers to fee mineral acreage owned in perpetuity by the Company.

# To Our Shareholders

2006 was a year of change for Panhandle Royalty Company, and as we enter 2007, more changes lie ahead. HW Peace II retired as president and CEO of the Company in March. Michael C. Coffman and Ben D. Hare assumed Co-President positions and maintained their respective chief financial and chief operating officer roles. New strategies and objectives were developed and presented to the board of directors. With the board's input and guidance, we have begun to implement certain changes in the Company's operational philosophies which we believe will allow the Company to achieve its primary goal of significantly adding to Panhandle's oil and gas production levels and reserve base. We know this is the most important objective for your Company and will lead to building solid underlying values and profitable growth for your Company.

2006 was also a year of achievements for the Company as records were set in:

- Revenue, net income and cash flow
- The amount of natural gas reserves
- The amount of natural gas production

2006 financial results are completely disclosed and analyzed in the attached Form 10-K, which was filed with the Securities and Exchange Commission in December 2006. As you will see in the 10-K financial statements, 2006 income was negatively impacted by a non-cash flow $3,009,953 provision for impairment, which was recorded on certain oil and gas properties. This impairment provision was primarily the result of one field in which the more recent wells drilled, and especially the last well drilled, did not yield anticipated sustained production or reserve volumes. Also, the decline in natural gas prices in the latter part of fiscal 2006 caused the natural gas prices used in the impairment calculation to be substantially lower than last year's prices. In spite of the impairment change, your Company was able to have a very successful financial and operational year. Discussion of 2006 operations is contained in the Operations Highlights section of this report.

When you are reviewing the Form 10-K, take special note of the prices used to calculate reserves and estimated future net cash flows from those reserves. The Securities and Exchange Commission requires that prices in effect on the last day of the Company's fiscal year be used in these calculations. For September 30, 2006, these prices were $60.50 per barrel of oil and $3.49 per mcf of natural gas. Compare those prices to the September 30, 2005, prices of $64.18 per barrel of oil and $11.54 per mcf and you can see why estimated future net cash flows for 2006 declined so drastically. Since September 30, 2006, natural gas prices have recovered and are now in the mid to upper $5 per mcf range.

2007 is expected to be another exciting year for the Company. Your board of directors approved the largest capital expenditure budget in Company history for 2007. The budget includes $31,500,000 for drilling and equipping wells and $1,500,000 for both leasehold purchases and workover expenses on existing wells.

The Operations Highlights section of this report discusses the new strategies and the major areas in which the Company expects to be expending drilling dollars in 2007. The unconventional natural gas resource plays discussed will be especially exciting to watch develop over the next few years. These plays have the potential to substantially increase the value of the Company.

To assure funding is available for the 2007 and beyond drilling program, the Company has entered into a new $50 million credit facility with Bank of Oklahoma, N.A. At our request, the initial borrowing base was set at $10 million to minimize the non-use fees, but the borrowing base can be increased when needed. The Company also entered into its first hedging arrangement, which will affect gas sold in calendar 2007. The exact terms of these natural gas collars are discussed on page 38 of the Form 10-K. These hedging arrangements cover only a portion of the Company's expected natural gas production for 2007 and should help provide some buffer against potential future changes in natural gas prices.

Finally, you will see in the enclosed Notice of Annual Shareholder's Meeting and Proxy Statement that the board of directors is asking the shareholders to approve two significant changes for the Company. First, we recommend changing the Company's name to Panhandle Oil and Gas Inc. We believe the change will clear up confusion as to Panhandle's corporate status. The inclusion of Royalty in the name has led many to think the Company operates as a royalty trust or that the Company owns only royalty interests in oil and gas wells, neither of which is accurate. This is a simple problem to solve and we urge each of you to vote to change the Company's name to one which will reflect the current operating status of the Company. Second, we recommend increasing the authorized common shares from 12,000,000 to 24,000,000. There are 8,422,259 shares currently outstanding. The proposed increase would provide the Company the flexibility of having shares available for strategic transactions to encourage the Company's growth, including possible stock splits, acquisitions of oil and gas reserves or business combinations where shares might be used to fund part of the purchase price. We currently have no plans to issue any of the proposed authorized shares. Again, we encourage each of you to vote for this proposed increase in authorized shares.

Thank you to our board of directors for their hard work, guidance and governance throughout the year, and be assured we are all committed to continue to build solid underlying value and consistent profitable growth for your Company.

E. Chris Kauffman
Chairman

Michael C. Coffman
Co-President/CFO

Ben D. Hare
Co-President/COO

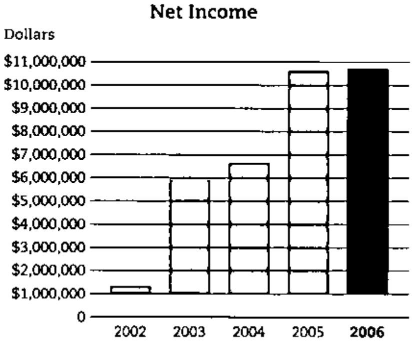
*The unconventional natural gas resource plays will be especially exciting to watch develop over the next few years. These plays have the potential to substantially increase the value of the Company.*

# Financial and Operating Highlights

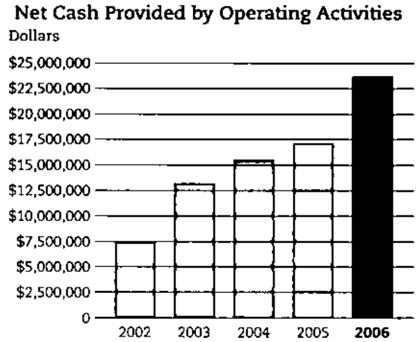
| | 2006 | 2005 | 2004 |
|---|---|---|---|
| **Revenue and Earnings** | | | |
| Revenue | $ 37,485,680 | $ 33,598,175 | $ 24,606,609 |
| Net income | $ 10,574,219 | $ 10,484,786 | $ 6,729,825 |
| Diluted earnings per share | $ 1.25 | $ 1.24 | $ 0.80 |
| Average diluted shares outstanding | 8,479,406 | 8,450,238 | 8,457,602 |
| Net cash provided by operating activities | $ 23,736,931 | $ 17,154,171 | $ 15,515,300 |
| Capital expenditures | $ 22,624,040 | $ 14,741,637 | $ 10,946,471 |
| **Exploration and Production** | | | |
| Total proved reserves (mcf equivalent) | 34,320,985 | 31,252,341 | 32,812,205 |
| Estimated future net cash flow from reserves (before income taxes): | | | |
| At September 30 pricing, Discounted @ 10% | $ 68,636,668 | $ 190,395,273 | $ 97,212,618 |
| Percent of reserves natural gas | 90% | 88% | 86% |
| Total production (mcf equivalent) | 4,881,976 | 4,620,712 | 4,553,193 |
| Average gas price ($/mcf) | $ 6.94 | $ 6.24 | $ 5.03 |
| Average oil price ($/barrel) | $ 63.44 | $ 51.30 | $ 35.89 |
| Average price per mcf equivalent | $ 7.38 | $ 6.54 | $ 5.18 |
| Average production costs ($/mcf) | $ 1.08 | $ 1.04 | $ 0.90 |

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

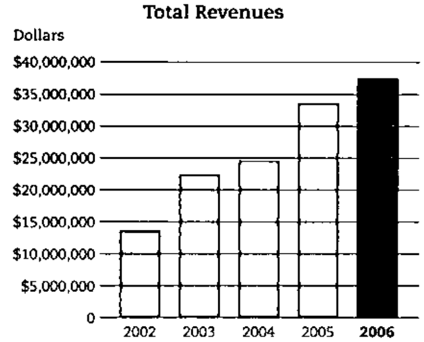
Net Income




Net Cash Provided by Operating Activities




Total Revenues



# Operations Highlights

Fiscal year 2006 was a successful year for operations because Panhandle was able to achieve the objective of our primary strategy to increase reserves and production. At various presentations to the investment community, three key strategic directions to be implemented in order to grow the Company were put forth. Those strategies are:

**(1) Achieve significant reserve and production growth**

- Increase working interest percentage
- Increase reserve target size

**(2) Develop new ventures**

- Evaluate potential acquisitions
- Selectively participate in unconventional plays
- Diversify geologic/geographic areas

**(3) Exploit legacy assets**

Although not fully implemented, the Company made good progress on these strategies, which enabled it to increase reserves and production.

In 2006, Panhandle's average working interest percentage increased to 5.6% compared to an average of 5% for FY2005. Compared to 2005, 24 additional wells were approved with greater than a 10% working interest. In terms of increasing target size, 12 new wells with greater than 3.0 BCF gross, pre-drill gas reserves were approved over 2005 and five wells with greater than 10 BCF potential were approved for participation. If the company continues on this path, it will be drilling bigger potential wells and will own more of the reserves and production if successful.

Several potential acquisitions were evaluated in 2006, but none were consummated. Because of high commodity prices during much of the year, expectations of valuations by the sellers were high. Also, the offerings evaluated were highly weighted toward proved undeveloped reserves relative to proved producing reserves.

In subsequent sections of this report, discussions will cover unconventional plays where Panhandle is participating in drilling and some areas where we have diversified geologically and geographically. These strategies, as implemented, will expose Panhandle to prospects with the potential to increase reserves and production significantly.

In 2006, Panhandle participated in 118 working interest wells that were completed, drilling or testing at year end, and had a royalty interest in 235 wells in the same categories.

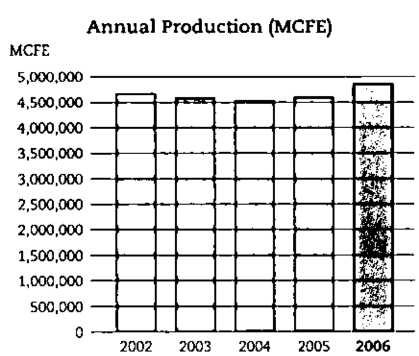
## Working Interest

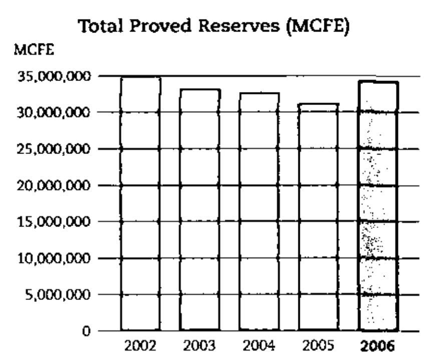
| Category | 2006 | 2005 | 2004 |
|---|---|---|---|
| Drilling | 6 | 11 | 18 |
| Testing | 11 | 18 | 32 |
| Producing | 98 (7 oil, 91 gas) | 107(9 oil, 98 gas) | 107 (14 oil,93 gas) |
| Dry Holes | 3 | 6 | 15 |
| Total | 118 | 142 | 172 |

## Royalty Interest

| Category | 2006 | 2005 | 2004 |
|---|---|---|---|
| Drilling | 22 | 14 | 5 |
| Testing | 2 | 30 | 23 |
| Producing | 194 (21 oil, 173 gas) | 143 (12 oil, 131 gas) | 112 (16 oil, 96 gas) |
| Dry Holes | 17 | 14 | 6 |
| Total | 235 | 201 | 146 |

The working interest activity resulted in seven oil wells, 91 gas wells and three dry holes. The royalty interest activity resulted in 21 oil wells and 173 gas wells. In terms of working interest wells, Panhandle is becoming much more efficient over time by drilling fewer wells with bigger interests, and with higher productivity and reserves. In 2006 the Company had fewer new producing wells (98) as compared to 2005 (107) and 2004 (107), yet still increased production and reserves while drilling fewer total wells.



Actual dollars spent on exploration, development and land acquisition in 2006 was approximately $22,600,000 (See Note 9, Notes to Consolidated Financial Statements). In 2005, Panhandle spent $14,740,000 on exploration, development and property acquisition. Panhandle purchased 1,266 acres of new non-producing leasehold in 2006 at a total cost of $446,027.

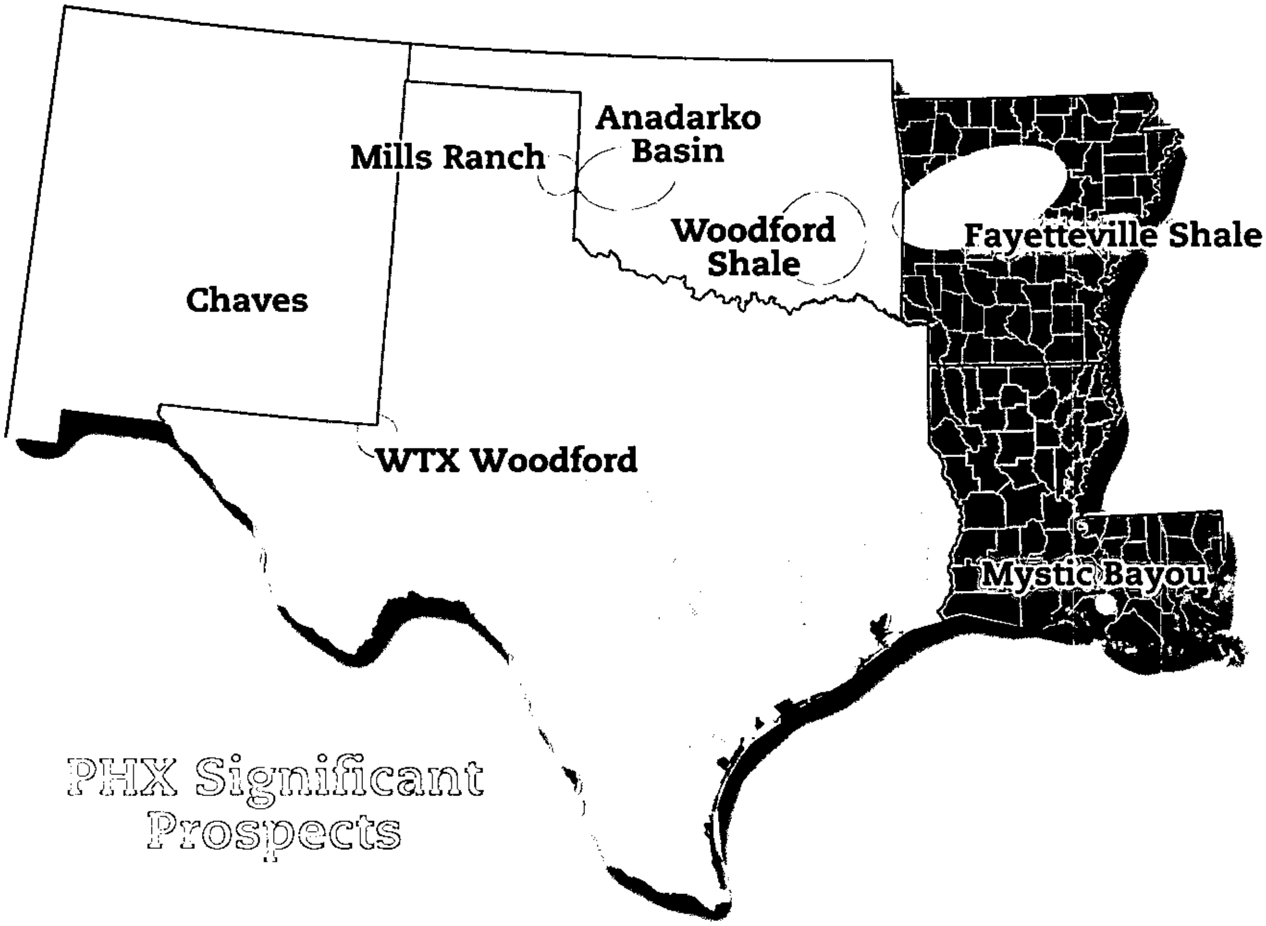
## Unconventional Plays

Significant exploration and drilling is rapidly building in several geological provinces in which Panhandle owns fee mineral acreage. These plays are frequently referred to as unconventional reservoirs or resource plays because of the nature of the reservoir rock. Unconventional resource plays are usually tight, fractured rocks which serve simultaneously as the source of the hydrocarbons as well as the reservoir. These plays generally have a wide area distribution that offers the opportunity for numerous horizontal well locations.

Panhandle has acreage in the Fayetteville shale play in Arkansas, the Woodford and Caney shale play in Oklahoma, the Woodford shale play in far west Texas, and the Wolfcamp play in Chaves County, New Mexico. All of these plays have had significant and growing activity by the industry in 2006.

In 2005, Panhandle leased for five years all 9,000 acres of its non-producing Arkansas minerals in the Fayetteville shale trend for an approximate $2,000,000 bonus and a 3/16th royalty interest. The company retained the right to participate with a working interest in wells drilled in 65 of the sections leased. The average working interest available to Panhandle in these sections will be approximately 4.6%. The Company has committed to participate with a working interest in four wells to date. Active operators in this play have publicly announced average flow rates of 1.7 million cubic feet of gas per day (MMCFD) and potential reserves of 2.0 to 3.0 billion cubic feet of gas per completed well.

In southeastern Oklahoma, primarily in Coal, Hughes, Pittsburgh and Atoka counties, there is abundant drilling activity in the Woodford shale. In 2006, the Company had a working interest in 17 wells and a royalty interest in seven wells. At year end, four of the working interest wells had been completed, three were testing and the rest were drilling or scheduled to drill. One vertical well was plugged and replaced with a horizontal well. Of the completed horizontal wells, initial potential flow rates ranged from 3.0 to 4.0 MMCFD. Four of the royalty wells had been completed as gas wells at year end. Panhandle has approximately 10,250 mineral acres in the core of the play and has mineral acreage ownership in 404, 640-acre sections. Working interests will range from less than 1% up to 35%, with the average working interest expected to be approximately 4%. At year end, the average cost of a completed well in this play exceeded $4 million. Active operators in the Woodford have publicly announced flow rates of up to 10.0 MMCFD and potential reserves of 2.0 to 3.0 BCF per well.




The Woodford shale is also present in far west Texas, where Panhandle has 2,600 mineral acres in Winkler and Andrews counties. Approximately 1,800 acres are in 24 contiguous, 640-acre sections with mineral acreage ownership ranging from 8% to 17% and averaging 12.5%. This play is in the early stages of evaluation, and its potential is not as well known as that of the Woodford in Oklahoma. One well was drilling on Company minerals at year end, and to minimize risks, the Company elected to participate with half of its 8.33% working interest. Initial published reports indicate potential reserves to be 3.0 BCF per well with projected development on 160-acre spacing.

In Chaves County, New Mexico, the Wolfcamp formation is a developing resource play. Panhandle has 7,300 acres in or near activity in this trend and participated in two wells during 2006. One well was fracture stimulated and testing at year end (9.4% working interest) and the other (4.7% working interest) had reached total depth and was waiting on testing to begin. Operators in the area have estimated per-well reserves to range from 1.8 to 2.0 BCF. The Company has mineral interests in 112, 640-acre sections with the average interest being 10%. It is not known at this time how much of the company's acreage will be prospective.

## Geological/Geographical Diversification

Earlier in this report, one of the strategic directions identified for the Company was to diversify into other geological and geographical areas to expose the Company to larger reserve targets and higher production rates. Two projects were approved in 2006 to accomplish that goal. One was the drilling of the Mills Ranch prospect in Wheeler County, Texas. Although the Company has previously participated in shallower wells in the Texas panhandle, Mills Ranch is the first deep test for the Company. The Mills Ranch 1-96 spudded in March 2006 and drilled to a target depth of 25,000 feet and commenced testing the Hunton Formation. Panhandle has 161 acres in the drill site section and elected to participate with a 9.6% working interest and a 12.5% net revenue interest. Potential gross reserves for this well range from 15 BCF to more than 20 BCF.

Another project for diversification is the Mystic Bayou prospect in St. Martin Parish, Louisiana. The Company committed to a two-well drilling program based on 3-D seismic data. The objective is the Planulina formation at 16,000 feet with reserve potential of 15 BCF and 1.3 MMBO per well. The first well, the Williams Land Co. #1, was spudded in November 2006. Panhandle has a 6.27% working interest before casing point, 5.96% working interest after casing point, and a 4.4% net revenue interest. The well encountered a Planulina sand that was not reservoir quality and was plugged and abandoned as a dry hole in December.

## Exploit Legacy Assets

Panhandle Royalty Company has excellent legacy assets because of its extensive mineral holdings. The Company will continue to exploit those assets when opportunities arise using the cash generated as a base to fund much of its activity. Those assets have proven to be an important part of the Company's ability to participate in the unconventional plays.

In terms of more conventional resources, the mineral holdings account for a large portion of the Company's annual activity, especially in western Oklahoma. In the four-county area of Beckham, Custer, Dewey and Roger Mills, the Company has 13,915 mineral acres and 5,991 acres of leasehold. In 2006, Panhandle's drilling schedule had 87 working interest wells in those four counties with an average working interest of 4.8%. For 2006, the Company had 67 producing wells, one dry hole and six wells drilling or testing. The remaining wells were scheduled to drill. In addition, there were 60 royalty interest wells on the schedule, with 36 producers and three dry holes.

Another legacy asset is the Potato Hills field in Pushmataha County, which has a gross estimated ultimate recovery of more than 250 BCF. In 2006, the Company participated in seven successful development wells, with initial potential tests averaging 2.9 MMCFD. Working interests range from 2.0% to 6.3% and averaged 4.6%.


We are all committed to
continue to build solid
underlying value
and consistent
profitable growth
for your Company.

# Officers

**Ben D. Hare**
Co-President
Chief Operating Officer

**Michael C. Coffman**
Co-President
Chief Financial Officer
and Treasurer

**Ben Spriestersbach**
Vice President, Land

**Lonnie J. Lowry**
Vice President,
Controller and
Secretary

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 Auditors

Ernst & Young LLP
Oklahoma City, Oklahoma

Stock Transfer & Dividend
Paying Agent

UMB Bank
Securities Transfer Division
PO Box 410064
Kansas City, Missouri 64141-0064
1-800-884-4225

# Board of Directors

**Bruce M. Bell**
Post Oak Oil Company
(2) (3) (4)

**Michael C. Coffman**
Co-President
Chief Financial Officer
and Treasurer

**Ben D. Hare**
Co-President
Chief Operating Officer

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

**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

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PANHANDLE
ROYALTY
COMPANY

Annual Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended September 30, 2006

Commission File Number: 0-9116

**PANHANDLE ROYALTY COMPANY**
(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 305, 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. ___

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, 2006, was $141,933,276. As of December 4, 2006, 8,422,529 shares of Class A Common stock were outstanding.

**Documents Incorporated By Reference**

The information required by Part III of this Report, to the extent not set forth herein, is incorporated by reference from the registrant's Definitive Proxy Statement relating to the annual meeting of stockholders to be held on March 8, 2007, 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 Royalty Company ("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. Panhandle's 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.

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 Oklahoma, New Mexico and Texas. Properties are also located in nine 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 and owned interests in certain oil and gas and real estate partnerships and an office building in Tulsa. 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 305, 5400 North Grand Blvd., Oklahoma City, OK 73112 (405)948-1560, fax (405)948-2038. Its website is located at www.panra.com.

The Company makes periodic SEC reports on Forms 10-Q and Forms 10-K, the Company's annual report to shareholders and current press releases 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 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 and its working and royalty interests in producing wells, are centered in Oklahoma with some activity in New Mexico, Texas, Arkansas and Kansas. 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 in 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, 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 in 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 prices. A more thorough discussion of the hedging arrangements is contained in the Management's Discussion and Analysis of Financial Condition and Results of Operation section of this report contained in 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 acreage ownership, coupled with its own geologic and economic evaluation, 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 oil and gas reserves is essential to the ultimate realization of value from the Company's mineral 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 purchasing 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 2006, sales through two separate operators accounted for approximately 14% and 11%, 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 usually reasonably 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.

## GOVERNMENTAL REGULATION

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. 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.

## EMPLOYEES

At September 30, 2006, Panhandle employed sixteen persons on a full-time basis. Four of the employees are executive officers and the co-presidents are also directors 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;
- 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.

**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 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 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 with well operators, as the Company does not operate any of its wells.

Drilling for oil and natural gas may involve 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 a 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 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 financial reports.

**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 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.

## ITEM 2 PROPERTIES

As of September 30, 2006, Panhandle's principal properties consisted of perpetual ownership of 254,778 net mineral acres, held principally in tracts in Oklahoma, New Mexico, Texas and nine other states. The Company also held leases on 20,742 net acres of minerals primarily in Oklahoma. At September 30, 2006, Panhandle held royalty and/or working interests in 4,174 producing oil or gas wells, and 41 wells in the process of being drilled or completed.

Panhandle does not have current abstracts or title opinions on all mineral properties owned and, therefore, cannot be certain that it has unencumbered title to all of its 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

The following table of mineral interests owned reflects, as of September 30, 2006, 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 (2) | Gross Acres Leased (2) | Net Acres Open (3) | Gross Acres Open (3) |
|---|---|---|---|---|---|---|---|---|
| Arkansas | 10,048 | 44,556 | 1,079 | 2,936 | 8,959 | 41,581 | 10 | 39 |
| Colorado | 8,326 | 39,299 | 109 | 219 | 30 | 200 | 8,187 | 38,880 |
| Florida | 5,606 | 12,239 | | | | | 5,606 | 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 | 113,078 | 939,674 | 32,223 | 266,110 | 3,336 | 24,067 | 77,519 | 649,497 |
| South Dakota | 1,825 | 9,300 | | | | | 1,825 | 9,300 |
| Texas | 43,187 | 361,270 | 7,060 | 67,436 | 1,206 | 6,777 | 34,921 | 287,057 |
| OTHER | 44 | 279 | | | | | 44 | 279 |
| **Total:** | **254,778** | **1,675,126** | **41,975** | **345,106** | **13,877** | **75,144** | **198,926** | **1,254,876** |

(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 |
|---|---|---|---|---|---|
| | | 2007 | 2008 | 2009 | |
| Kansas | 2,117 | | | | 2,117 |
| Oklahoma | 16,782 | 914 | 1,375 | 548 | 13,945 |
| Texas | 470 | | | | 470 |
| Other | 1,373 | | | | 1,373 |
| TOTAL | 20,742 | 914 | 1,375 | 548 | 17,905 |

## 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. 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, 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 many cases, this means the Company has received some type of notice from the operator that a well will be drilled. All reserve quantity estimates were prepared by Campbell & Associates, Inc., Norman, Oklahoma, a consulting petroleum engineering firm. The Company's reserve estimates are not filed with any other federal agency.

| Proved Developed Reserves | Barrels of Oil | Mcf of Gas |
|---|---|---|
| September 30, 2006 | 566,110 | 25,322,756 |
| September 30, 2005 | 613,536 | 24,011,062 |
| September 30, 2004 | 710,513 | 24,086,120 |
| Proved Undeveloped Reserves | | |
| September 30, 2006 | 9,081 | 5,547,083 |
| September 30, 2005 | 20,787 | 3,435,341 |
| September 30, 2004 | 49,729 | 4,164,633 |
| Total Proved Reserves | | |
| September 30, 2006 | 575,191 | 30,869,839 |
| September 30, 2005 | 634,323 | 27,446,403 |
| September 30, 2004 | 760,242 | 28,250,753 |

These reserves exclude approximately 1.2 to 1.6 Bcf of $CO_2$ 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 guidelines. 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, 2006, 2005, 2004 were as follows: 2006 - $60.50, $3.49; 2005 - $64.18, $11.54; 2004 - $44.68, $5.42. 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)

| | 9-30-06 | 9-30-05 | 9-30-04 |
|---|---|---|---|
| Proved Developed | $ 94,939,418 | $ 265,189,328 | $ 129,410,259 |
| Proved Undeveloped | $ 10,734,504 | $ 31,671,502 | $ 18,782,490 |
| Total Proved | $ 105,673,922 | $ 296,860,830 | $ 148,192,749 |

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

| | 9-30-06 | 9-30-05 | 9-30-04 |
|---|---|---|---|
| Proved Developed | $ 62,920,576 | $ 169,417,252 | $ 84,400,194 |
| Proved Undeveloped | $ 5,716,092 | $ 20,978,021 | $ 12,812,424 |
| Total Proved | $ 68,636,668 | $ 190,395,273 | $ 97,212,618 |

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 for 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 9-30-06 | Year Ended 9-30-05 | Year Ended 9-30-04 |
|---|---|---|---|
| Bbls - Oil | 97,139 | 101,581 | 114,986 |
| Mcf - Gas | 4,299,142 | 4,011,226 | 3,863,277 |
| Mcfe | 4,881,976 | 4,620,712 | 4,553,193 |

Gas production includes 192,957, 183,743 and 176,605 Mcf of CO2 sold at average prices of $.65, $.51 and $.41 per Mcf for the years ended September 30, 2006, 2005 and 2004, 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 9-30-06 | Year Ended 9-30-05 | Year Ended 9-30-04 |
|---|---|---|---|
| Per Bbl, Oil | $ 63.44 | $ 51.30 | $ 35.89 |
| Per Mcf, Gas | $ 6.94 | $ 6.24 | $ 5.03 |
| Per Mcfe | $ 7.38 | $ 6.54 | $ 5.18 |
| Average Production (lifting costs) | | | |
| (Per Mcfe of Gas) | | | |
| (1) | $ 0.49 | $ 0.52 | $ 0.48 |
| (2) | $ 0.59 | $ 0.52 | $ 0.42 |
| | $ 1.08 | $ 1.04 | $ 0.90 |

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

Approximately 28% 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, 2006. Panhandle owns fractional royalty interests or fractional working interests in these wells. The Company does not operate any wells.

| | Gross Wells | Net Wells |
|---|---|---|
| Oil | 955 | 18.92 |
| Gas | 3,219 | 73.85 |
| TOTAL | 4,174 | 92.77 |

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

As of September 30, 2006, Panhandle owned 345,106 gross developed mineral acres and 41,975 net developed mineral acres. Panhandle has also leased from others 178,312 gross developed acres, which contain 17,905 net developed acres.

## UNDEVELOPED ACREAGE

As of September 30, 2006, Panhandle owned 1,330,020 gross and 212,803 net undeveloped mineral acres, and leases on 30,694 gross and 2,837 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, 2004 | 4.362204 | 0.322523 |
| Fiscal year ended September 30, 2005 | 5.485356 | 0.142047 |
| Fiscal year ended September 30, 2006 | 5.477069 | 0.139168 |
| **Exploratory Wells** | | |
| Fiscal year ended September 30, 2004 | 1.245048 | 0.305172 |
| Fiscal year ended September 30, 2005 | 0.584992 | 0.131758 |
| Fiscal year ended September 30, 2006 | 0.747225 | 0.159593 |
| **Purchased Wells** | | |
| Fiscal year ended September 30, 2004 | 0.009749 | 0 |
| Fiscal year ended September 30, 2005 | 1.660737 | 0 |
| Fiscal year ended September 30, 2006 | 0 | 0 |

## PRESENT ACTIVITIES

The following table sets forth the gross and net oil and gas wells drilling or testing as of September 30, 2006, in which Panhandle owns a royalty or working interest. These wells are not yet producing.

| | Gross Wells | Net Wells |
|---|---|---|
| Oil | 2 | 0.22875 |
| Gas | 39 | 1.19593 |

## 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 2007 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, 2006.

## PART II

## ITEM 5 MARKET FOR 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 two-for-one stock split, effective on January 9, 2006):

| Quarter Ended | High | Low |
|---|---|---|
| December 31, 2004 | $ 12.65 | $ 8.70 |
| March 31, 2005 | $ 15.84 | $ 10.55 |
| June 30, 2005 | $ 15.25 | $ 10.53 |
| September 30, 2005 | $ 22.50 | $ 13.88 |
| December 31, 2005 | $ 21.28 | $ 14.63 |
| March 31, 2006 | $ 20.33 | $ 17.48 |
| June 30, 2006 | $ 22.41 | $ 16.98 |
| September 30, 2006 | $ 19.53 | $ 17.27 |

As of December 4, 2006, there were 1,877 holders of record of Panhandle's Class A Common Stock.

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 2004 | $ 0.025 |
| March 2005 | $ 0.05 |
| June 2005 | $ 0.025 |
| September 2005 | $ 0.025 |
| December 2005 | $ 0.025 |
| March 2006 | $ 0.08 |
| June 2006 | $ 0.04 |
| September 2006 | $ 0.04 |

The Company's current line of credit loan agreement contains a provision limiting the paying or declaring of a cash dividend to twenty percent of net cash flow provided by operating activities from the Consolidated Statement of Cash Flows of the preceding twelve-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, | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2003 | 2002 |
| **Revenues** | | | | | |
| Oil & Gas Sales | $ 36,008,527 | $30,242,210 | $23,578,615 | $22,098,198 | $13,080,754 |
| Lease Bonuses | 410,984 | 2,214,992 | 115,938 | 72,765 | 41,497 |
| Interest & Other | 1,066,169 | 1,140,973 | 912,056 | 285,075 | 469,146 |
| | $ 37,485,680 | $33,598,175 | $24,606,609 | $22,456,038 | $13,591,397 |
| **Costs and Expenses** | | | | | |
| Lease Oper. Exp. & Prod. Taxes | $ 5,262,834 | $ 4,802,595 | $ 4,098,124 | $ 4,013,572 | $ 3,001,449 |
| Exploration Costs (A) | 222,892 | 784,741 | 236,939 | 469,224 | 417,971 |
| Depr. Depl. Amortization | 10,142,367 | 7,506,571 | 6,115,500 | 5,783,457 | 5,845,779 |
| Provision for Impairment | 3,009,953 | 232,295 | 841,687 | 692,220 | 1,116,234 |
| Loss on Sale of Assets | 119,282 | 291,452 | - | - | - |
| Gen. & Administrative | 3,335,899 | 4,545,208 | 3,033,437 | 2,666,177 | 2,263,908 |
| Interest Expense | 232,234 | 359,527 | 488,097 | 699,266 | 895,997 |
| | $ 22,325,461 | $18,522,389 | $14,813,784 | $14,323,916 | $13,541,338 |
| **Income Before Provision (Benefit) For Income Taxes** | $ 15,160,219 | $15,075,786 | $ 9,792,825 | $ 8,132,122 | $ 50,059 |
| Cumulative effect of accounting changes, net of taxes of $28,500 (B) | - | - | - | 46,500 | - |
| Provision (Benefit) for Income Taxes | 4,586,000 | 4,591,000 | 3,063,000 | 2,217,000 | (293,000) |
| **Net Income** | $ 10,574,219 | $10,484,786 | $ 6,729,825 | $ 5,961,622 | $ 343,059 |
| Basic Earnings per share | $ 1.25 | $ 1.25 | $ 0.80 | $ 0.71 | $ 0.04 |
| Diluted Earnings per share | $ 1.25 | $ 1.24 | $ 0.80 | $ 0.71 | $ 0.04 |
| Dividends Declared per share | $ 0.185 | $ 0.125 | $ 0.09 | $ 0.07 | $ 0.07 |
| Weighted Average Shares Outstanding (C) | | | | | |
| Basic | 8,479,406 | 8,390,280 | 8,357,566 | 8,325,488 | 8,271,488 |
| Diluted | 8,479,406 | 8,450,238 | 8,457,602 | 8,414,852 | 8,359,888 |
| Net Cash Provided by Operating Activities | $ 23,736,931 | $17,154,171 | $15,515,300 | $13,198,368 | $ 7,481,195 |
| Total Assets | $ 70,949,242 | $61,241,692 | $54,186,362 | $49,402,534 | $44,837,060 |
| Long-Term Debt | $ 1,166,649 | $ 3,166,653 | $ 8,516,657 | $12,666,661 | $14,024,000 |
| Shareholders' Equity | $ 49,065,697 | $38,635,350 | $28,700,515 | $22,527,685 | $16,953,294 |

All share and per share amounts are adjusted for the effects of two-for-one 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 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, are expected to again increase in 2007, 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, | | | | |
|---|---|---|---|---|---|
| | 2006 | Percent Incr or (Decr) | 2005 | Percent Incr or (Decr) | 2004 |
| Production: | | | | | |
| Oil (Bbls) | 97,139 | (4%) | 101,581 | (12%) | 114,986 |
| Gas (Mcf) | 4,299,142 | 7% | 4,011,226 | 4% | 3,863,277 |
| Mcfe | 4,881,976 | 6% | 4,620,712 | 1% | 4,553,193 |
| Average Sales Price: | | | | | |
| Oil (per Bbl) | $ 63.44 | 24% | $ 51.30 | 43% | $ 35.89 |
| Gas (per Mcf) | $ 6.94 | 11% | $ 6.24 | 24% | $ 5.03 |
| Mcfe | $ 7.38 | 13% | $ 6.54 | 26% | $ 5.18 |

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 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 $0.63 in 2006 as compared to $0.62 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 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. 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.

## Liquidity and Capital Resources

At September 30, 2006, the Company had positive working capital of $4,997,714 as compared to $3,470,006 at September 30, 2005. The increase is a result of an income tax receivable created by the estimated federal income tax payment made in March 2006 and the directors' deferred compensation liability being reclassified to equity in October 2005. These items were offset by an increase in accounts payable, relating to increased drilling expenditures. 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 costs for drilling rigs, field services and equipment continue to increase and the drilling of gas resource wells continues to increase in number.

Cash flow from operating activities increased 38% over last year. Capital expenditures for oil and gas activities for 2006 amounted to $22,624,040, as compared to $14,741,637 for 2005. Management currently expects capital expenditures for oil and gas activities to be approximately $33,000,000 for 2007. This includes expected well drilling and equipment costs of $31.5 million and $1.5 million for both leasehold acreage purchases and workover expenses on existing wells. The $31.5 million drilling budget is expected to include expenditures of approximately $14.5 million on gas resource drilling projects principally in southeast Oklahoma and west Texas, $12.5 million on drilling projects in western Oklahoma and $4.5 million in onshore Gulf Coast drilling projects. Any acquisition of oil and gas properties would further increase capital expenditures.

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 borrowing base of the current bank line-of-credit can be substantially increased if needed. 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 2007, the expected capital expenditure level discussed above, and no meaningful acquisitions of oil and gas properties, borrowings of $10-15 million in fiscal 2007 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 refinanced its credit facility with BancFirst of Oklahoma City, Oklahoma with a credit facility from Bank of Oklahoma (BOK). The BOK Agreement consists 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 matures on September 1, 2007 and the revolving loan matures on October 31, 2009. Monthly payments, beginning December 1, 2006, on the term loan are $250,000, plus accrued interest. Borrowings under the revolving loan are due at maturity. The term loan bears interest at 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 prime 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 the bank, in its sole discretion, believes 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 of treasury stock, and require the Company to maintain certain financial ratios. At September 30, 2006 the Company was in compliance with the covenants of the BancFirst agreement.

The table below summarizes the Company's contractual obligations, under the BancFirst facility, as of September 30, 2006:

| | 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 | $ 3,166,653 | $ 2,000,004 | $ 1,166,649 | $ - | $ - |

Hedging

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

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

2005 Compared to 2004

Overview

The Company recorded net income of $10,484,786 in 2005, compared to net income of $6,729,825 in 2004. Revenues and consequently net income were larger as a result of increased oil and gas sales revenues generated by significant increases in the average sales prices of oil and natural gas in 2005 as compared to 2004. In addition, the Company was able to increase lease bonus revenue by approximately $2,100,000 in 2005. New leasing activity was the result of an industry wide increase in drilling activity brought on by the increased market price of oil and gas.

Revenues

Total revenues increased 35% to $33,306,723 in 2005 compared to $24,606,609 in 2004. The majority of the increase was due to increases in the average sales price for oil and natural gas in 2005 per the above operating data. New production from the Company's drilling activity more than replaced the normal production decline of existing gas wells and the sale in 2005 of approximately 3% (on an annualized basis) of the Company's gas production. These sales of non-core assets were accomplished throughout 2005. Gas production increased 4% for the year in spite of the asset sales. Oil wells beginning production in 2005 could not replace the decline in existing oil production. As the Company is concentrating on the drilling of gas wells, this trend of increasing gas production and decreasing oil production should continue.

Lease bonus revenue increased $2,099,054 in 2005, substantially all of which is due to the leasing of all of the Company's non-producing mineral acreage in Arkansas. The total lease bonus, net of associated basis, for the approximate 9,000 Arkansas mineral acres was $1,879,467.

Lease Operating Expenses and Production Taxes (LOE)

LOE continues to increase each year due to increases in the number of working interest wells in which the Company has an interest, increasing repairs and maintenance needed for existing older wells and normal inflation of costs. Actual well operating costs were $2,877,972 in 2005 as compared to $2,592,911 in 2004. Gross production taxes are paid as a percentage of oil and gas sales revenues and therefore increased in 2005 to $1,924,623, an increase of $419,410 over 2004.

Exploration Costs

Exploration costs increased $547,802 or 231% in 2005 as compared to 2004. 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. In 2004, there were no high-cost exploratory dry holes as compared to three such wells in 2005.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased $1,391,071 or 23% in 2005 as compared to 2004. Increased DD&A expenses in 2005, as compared to 2004, are a result of rapid decline rates on many wells which have been drilled and gone on production in the last two years coupled with higher costs on these recently completed wells, which then must be depreciated. The high initial production rates result in an inordinate amount of the wells' total estimated reserves being produced rapidly, which then causes the units of production DD&A being heavily weighted to the front end of these wells' lives.

Provision for Impairment

The provision for impairment decreased $609,392 or 72% in 2005 as compared to 2004. The decrease in impairment charges was principally the result of increased market prices for oil and natural gas. Higher market prices dramatically change the economic evaluation of properties and the calculation of potential impairment.

General and Administrative Costs (G&A)

G&A costs increased $1,511,771 or 50% in 2005. Personnel related expenses (including salaries, payroll taxes, insurance and ESOP expenses) increased approximately $250,000 in 2005. Professional fees including: audit, oil and gas land brokers, engineering and Sarbanes-Oxley internal control review assistance increased $291,000 in 2005 as compared to 2004. G&A expense related to the Non-Employee Directors Deferred Compensation Plan (the "Plan") increased approximately $682,000 in 2005. The increase resulted from the Company recognizing a charge to G&A to adjust the potential shares (approximately 31,000 shares) in the Plan to market price at September 30, 2005. The non-employee directors have elected to defer payment of directors' fees with future payment (in cash or shares) indexed to the Company's stock performance. Subsequent to 2005 fiscal year end, the Company's board of directors voted to amend the Plan to provide future payment only in common stock of the Company. That change will eliminate the requirement to adjust the liability for changes in market price of the Company's common stock for 2006 and future fiscal periods.

### Interest Expense

Interest expense decreased $128,570 or 26% in 2005 because of lower average outstanding bank debt balances.

### Provision for Income Taxes

The provision for income taxes increased in 2005 due to a substantial increase in income before taxes (as discussed above). The Company continued to be able to utilize excess percentage depletion on its oil and gas properties to reduce its tax liability, and its effective tax rate from the federal and state statutory rates. The effective tax rate was approximately 30% in 2005, 31% in 2004 and 27% in 2003.

## 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, 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.

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 4,000 wells. Thus, obtaining timely production data from the well operators is extremely difficult. This requires the Company to utilize past production receipts 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. 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 DISCLOSURE 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 2006 production, a $.10 per Mcf change in the price received for natural gas production would result in a corresponding $430,000 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 $97,000 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 term loan bears interest at 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%. At September 30, 2006, the Company had $3,166,653 outstanding under these facilities. A change of .5% in the prime rate or on LIBOR would result in a change to interest expense of $15,833.

## ITEM 8 FINANCIAL STATEMENTS


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## 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) promulgated 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, 2006. 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, 2006, the Company's internal control over financial reporting was effective based on those criteria.

The Company's independent registered public accounting firm, Ernst & Young, LLP, has audited our assessment of the effectiveness of the Company's internal control over financial reporting as of September 30, 2006, as stated in their report which follows.

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

The Board of Directors and Stockholders
Panhandle Royalty Company

We have audited management's assessment, included in the accompanying "Management's Annual Report on Internal Control Over Financial Reporting," that Panhandle Royalty Company (the Company) maintained effective internal control over financial reporting as of September 30, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO criteria). The Company'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. Our responsibility is to express an opinion on management's assessment and 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control 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, management's assessment that the Company maintained effective internal control over financial reporting as of September 30, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2006, 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 the Company as of September 30, 2006 and 2005, and the related consolidated statements of income, stockholders' equity and cash flows for each of the three years in the period ended September 30, 2006 and our report dated December 6, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 6, 2006

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Panhandle Royalty Company

We have audited the accompanying consolidated balance sheets of Panhandle Royalty Company (the Company) as of September 30, 2006 and 2005, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2006. 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 Royalty Company at September 30, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2006, 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), the effectiveness of the Company's internal control over financial reporting as of September 30, 2006, 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 6, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 6, 2006

Panhandle Royalty Company
Consolidated Balance Sheets

| | September 30, 2006 | September 30, 2005 |
|---|---|---|
| **Assets** | | |
| Current Assets: | | |
| Cash and cash equivalents | $ 434,353 | $ 1,638,833 |
| Oil and gas sales receivables | 6,471,623 | 6,641,447 |
| Income tax and other receivables | 1,889,636 | 21,520 |
| Total current assets | 8,795,612 | 8,301,800 |
| Property and equipment at cost, based on successful efforts accounting: | | |
| Producing oil and gas properties | 103,129,158 | 84,388,067 |
| Non-producing oil and gas properties | 11,273,373 | 11,170,926 |
| Furniture and fixtures | 562,047 | 524,721 |
| | 114,964,578 | 96,083,714 |
| Less accumulated depreciation, depletion and amortization | 53,654,385 | 43,787,403 |
| Net properties and equipment | 61,310,193 | 52,296,311 |
| Investments | 596,280 | 396,424 |
| Other | 247,157 | 247,157 |
| Total assets | $ 70,949,242 | $ 61,241,692 |

(Continued on next page)

*See accompanying notes.*

Panhandle Royalty Company
Consolidated Balance Sheets

| | September 30, 2006 | September 30, 2005 |
|---|---|---|
| **Liabilities and Stockholders' Equity** | | |
| Current Liabilities: | | |
| Accounts payable | $ 1,564,176 | $ 700,242 |
| Accrued liabilities: | | |
| Deferred compensation | - | 1,335,305 |
| Interest | 15,649 | 23,129 |
| Other | 218,069 | 173,445 |
| Income taxes payable | - | 599,669 |
| Long-term debt due within one year | 2,000,004 | 2,000,004 |
| Total current liabilities | 3,797,898 | 4,831,794 |
| Long-term debt | 1,166,649 | 3,166,653 |
| Deferred income taxes | 15,498,750 | 13,321,750 |
| Asset retirement obligation and other noncurrent liabilities | 1,420,248 | 1,286,145 |
| Stockholders' equity: | | |
| Class A voting common stock, $.0166 par value; 12,000,000 shares authorized, 8,422,529 issued and outstanding (8,410,886 in 2005) | 140,375 | 140,182 |
| Capital in excess of par value | 1,924,587 | 1,715,206 |
| Deferred directors' compensation | 1,202,569 | - |
| Retained earnings | 45,798,166 | 36,779,962 |
| Total stockholders' equity | 49,065,697 | 38,635,350 |
| Total liabilities and stockholders' equity | $ 70,949,242 | $ 61,241,692 |

*See accompanying notes.*

Panhandle Royalty Company
Consolidated Statements of Income

| | Year ended September 30, 2006 | 2005 | 2004 |
|---|---|---|---|
| Revenues: | | | |
| Oil and gas sales | $ 36,008,527 | $ 30,242,210 | $ 23,578,615 |
| Lease bonuses and rentals | 410,984 | 2,214,992 | 115,938 |
| Gain on sales and interest | 529,804 | 745,800 | 5,436 |
| Income from partnerships | 536,365 | 395,173 | 906,620 |
| | 37,485,680 | 33,598,175 | 24,606,609 |
| Costs and expenses: | | | |
| Lease operating expenses and production taxes | 5,262,834 | 4,802,595 | 4,098,124 |
| Exploration costs | 222,892 | 784,741 | 236,939 |
| Depreciation, depletion and amortization | 10,142,367 | 7,506,571 | 6,115,500 |
| Provision for impairment | 3,009,953 | 232,295 | 841,687 |
| Loss on sale of assets | 119,282 | 291,452 | - |
| General and administrative | 3,335,899 | 4,545,208 | 3,033,437 |
| Interest expense | 232,234 | 359,527 | 488,097 |
| | 22,325,461 | 18,522,389 | 14,813,784 |
| Income before provision for income taxes | 15,160,219 | 15,075,786 | 9,792,825 |
| Provision for income taxes | 4,586,000 | 4,591,000 | 3,063,000 |
| Net Income | $ 10,574,219 | $ 10,484,786 | $ 6,729,825 |
| Basic earnings per common share: | | | |
| Net income | $ 1.25 | $ 1.25 | $ 0.80 |
| Diluted earnings per common share: | | | |
| Net income | $ 1.25 | $ 1.24 | $ 0.80 |

*See accompanying notes.*

# Panhandle Royalty Company
## Consolidated Statements of Stockholder's Equity

| | Common Stock Shares | Common Stock Amount | Capital in Excess of Par Value | Deferred Directors Compensation | Retained Earnings | Total |
|---|---|---|---|---|---|---|
| Balances at September 30, 2003 | 8,356,404 | $ 139,274 | $ 1,022,249 | $ - | $ 21,366,162 | $ 22,527,685 |
| Issuance of common shares to ESOP | 20,116 | 336 | 172,662 | - | - | 172,998 |
| Issuance of common shares to directors for services | 3,046 | 50 | 22,109 | - | - | 22,159 |
| Dividends declared ($.09 per share) | - | - | - | - | (752,152) | (752,152) |
| Net Income | - | - | - | - | 6,729,825 | 6,729,825 |
| 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 |

*See accompanying notes.*

Panhandle Royalty Company
Consolidated Statements of Cash Flows

| | Year ended September 30, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| **Operating Activities** | | | |
| Net income | $ 10,574,219 | $ 10,484,786 | $ 6,729,825 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, depletion, amortization and impairment | 13,152,320 | 7,738,866 | 6,957,186 |
| Deferred income taxes | 2,177,000 | 1,072,750 | 1,920,000 |
| Lease bonus income | (95,892) | (2,133,337) | 286,679 |
| Exploration costs | 222,892 | 784,741 | 236,939 |
| Gain on sale of assets | (415,951) | (365,288) | (6,959) |
| Equity in earnings of partnerships | (536,365) | (395,173) | (246,573) |
| Common stock issued to ESOP/Directors' Deferred Compensation Plan | 149,161 | 498,708 | 195,156 |
| Cash provided (used) by changes in assets and liabilities | | | |
| Oil and gas sales receivables | 169,824 | (1,678,455) | (973,115) |
| Income tax and other receivables | (1,889,363) | 218,375 | (122,473) |
| Accounts payable | 863,934 | (125,699) | 273,740 |
| Accrued directors' deferred compensation | (281,897) | 470,972 | 344,550 |
| Accrued interest payable | (7,480) | (7,807) | (9,277) |
| Other accrued liabilities | 254,198 | (8,937) | 60,410 |
| Income taxes payable | (599,669) | 599,669 | (130,788) |
| Total adjustments | 13,162,712 | 6,669,385 | 8,785,475 |
| Net cash provided by operating activities | 23,736,931 | 17,154,171 | 15,515,300 |
| | | | |
| **Investing Activities** | | | |
| Capital expenditures, including dry hole costs | (22,624,040) | (14,741,637) | (10,946,471) |
| Proceeds from leasing of fee mineral acreage | 493,652 | 2,304,383 | - |
| Distributions received from partnerships | 618,509 | 497,839 | 369,761 |
| Purchase of investment | (282,000) | - | - |
| Proceeds from sale of assets | 408,487 | 2,180,397 | 12,903 |
| Net cash used in investing activities | $(21,385,392) | $ (9,759,018) | $(10,563,807) |

(Continued on next page)

*See accompanying notes.*

Panhandle Royalty Company
Consolidated Statements of Cash Flows (continued)

| | Year ended September 30, 2006 | 2005 | 2004 |
|---|---|---|---|
| **Financing Activities** | | | |
| Borrowings under debt agreement | $ - | $ 11,350,000 | $ 6,825,000 |
| Payments of loan principal | (2,000,004) | (16,700,004) | (10,975,004) |
| Payments of dividends | (1,556,015) | (1,048,659) | (752,152) |
| Purchase and cancellation of common shares | - | - | - |
| Net cash used in financing activities | (3,556,019) | (6,398,663) | (4,902,156) |
| Increase (decrease) in cash and cash equivalents | (1,204,480) | 996,490 | 49,337 |
| Cash and cash equivalents at beginning of year | 1,638,833 | 642,343 | 593,006 |
| Cash and cash equivalents at end of year | $ 434,353 | $ 1,638,833 | $ 642,343 |
| **Supplemental Disclosures of Cash Flow Information** | | | |
| Interest paid | $ 219,898 | $ 367,333 | $ 496,441 |
| Income taxes paid, net of refunds received | $ 4,781,462 | $ 2,668,870 | $ 1,344,321 |
| **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 | $ 141,158 | $ 494,508 | $ 219,675 |

*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 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 83% 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 Royalty Company and its wholly owned subsidiaries after elimination of all material intercompany transactions.

Capitalized costs of certain oil and gas properties and gains and losses on sales of assets for prior years 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. 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, 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 Securities and Exchange Commission, 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 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 business.

## 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. Thus, 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, 2006 and 2005, 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, 2006 or 2005.

### 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**

The Company had not, through fiscal 2006, entered into derivative instruments to hedge the price risk on its oil or gas production. Beginning in calendar 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. Collar contracts set a minimum price, or floor, 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.

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

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

**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 $5,680,765 at September 30, 2006, consisting of perpetual ownership of mineral interests in several states, with 82% of the acreage in Oklahoma, Texas and New Mexico. As mentioned these mineral rights are perpetual and have been accumulated over the 80-year life of the Company. There are approximately 213,000 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 $41. 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 over a thirty-three year period on the Company's books. 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

**1. Summary of Significant Accounting Policies (continued)**

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 future cash flows. 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 $3,009,953, $232,295 and $841,687 respectively, for 2006, 2005 and 2004. The majority of the impairment recognized in 2005 and 2004 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 principally the result of a twenty-seven well field in which the more recent wells drilled were not up to earlier well results, and results of the last well drilled, which was a large interest well, were poor resulting in an impairment of the entire field.

**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, 2006 relating to the Company's retirement obligation for plugging liability:

| | Plugging Liability |
|---|---|
| Plugging Liability as of September 30, 2005 | $ 1,144,299 |
| Accretion of Discount | 88,837 |
| Liability Incurred in the Period | 141,158 |
| Plugging Liability as of September 30, 2006 | $ 1,374,294 |

## 1. Summary of Significant Accounting Policies (continued)

### 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.

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, 2006 and 2005, there were no such costs accrued.

### Earning 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 closing price 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.

**1. Summary of Significant Accounting Policies (continued)**

**Fair Values of Financial Instruments**

The carrying amounts reported in the balance sheets for cash and cash equivalents, receivables, accounts payable, accrued liabilities and income taxes payable 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 rate on the Company's term-loan being a rate which is approximately equivalent to market rates at September 30, 2006 for similar type debt based on the Company's credit worthiness.

**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 May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections – a replacement of APB Opinion No. 20 and SFAS No. 3." SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle and a change required by an accounting pronouncement when the pronouncement does not include specific transition provisions. SFAS No. 154 requires retrospective application of changes as if the new accounting principle had always been used. SFAS No. 154 is effective for fiscal years beginning after December 15, 2005, which is our fiscal year beginning October 1, 2006. The adoption of the pronouncement is not expected to have a material impact on the Company's financial position or results of operations.

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.

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 is effective for the first fiscal year ending after November 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.

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 $159,108 in 2007, $159,108 in 2008 and $92,813 in 2009. Total rent expense incurred by the Company was $153,164 in 2006, $158,203 in 2005 and $115,192 in 2004.

**3. Income Taxes**

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

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Current: | | | |
| Federal | $ 2,351,000 | $ 3,488,250 | $ 1,113,000 |
| State | 58,000 | 30,000 | 30,000 |
| | 2,409,000 | 3,518,250 | 1,143,000 |
| Deferred: | | | |
| Federal | 1,928,000 | 1,004,750 | 1,851,000 |
| State | 249,000 | 68,000 | 69,000 |
| | 2,177,000 | 1,072,750 | 1,920,000 |
| | $ 4,586,000 | $ 4,591,000 | $ 3,063,000 |

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:

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Provision for income taxes at statutory rate | $ 5,210,883 | $ 5,178,799 | $ 3,329,561 |
| Percentage depletion | (699,384) | (620,982) | (334,365) |
| State income taxes, net of federal benefit | 361,680 | 63,700 | 64,350 |
| State net operating loss carryforward benefit | (241,000) | - | - |
| Other | (46,179) | (30,517) | 3,454 |
| | $ 4,586,000 | $ 4,591,000 | $ 3,063,000 |

**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:

| | 2006 | 2005 |
|---|---|---|
| Deferred tax liabilities: | | |
| Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes | $ 16,538,959 | $ 13,933,416 |
| Deferred tax assets: | | |
| State net operating loss carry forwards | 368,890 | 220,340 |
| Deferred directors compensation and other | 671,319 | 391,326 |
| | 1,040,209 | 611,666 |
| Net deferred tax liabilities | $ 15,498,750 | $ 13,321,750 |

**4. Long-term Debt**

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

| | 2006 | 2005 |
|---|---|---|
| 4.56% loan | $ 3,166,653 | $ 5,166,657 |
| Current maturities of long-term debt | 2,000,004 | 2,000,004 |
| | $ 1,166,649 | $ 3,166,653 |

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 consists 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 matures on September 1, 2007, and the revolving loan matures on October 31, 2009. Monthly payments on the term loan are $250,000, plus accrued interest. Borrowings under the revolving loan are due at maturity. The term loan bears interest at 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 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, 2006, the Company was in compliance with the covenants of the BancFirst agreement.

The amounts of required principal payments under the BancFirst or the BOK agreement for the next five years, as of September 30, 2006, are as follows:

| | BancFirst | BOK |
|---|---|---|
| 2007 | $ 2,000,004 | $ 2,500,000 |
| 2008 | $ 1,116,649 | $ - |
| 2009 | $ - | $ - |
| 2010 | $ - | $ 666,653 |
| 2011 | $ - | $ - |

**5. Shareholders' Equity**

On December 18, 2003, 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 6,000,000 shares to 12,000,000 shares and effect a 2-for-1 stock split of the outstanding Class A Common Stock and a corresponding reduction of the par value per share from $.03333 to $.01666. On February 27, 2004, these proposals were put forth to a vote of the shareholders, for which a majority of the shareholders voted in favor of each proposal, causing these proposals to become effective on such date. The Class A Common Stock split was effected in the form of a stock dividend, distributed on April 15, 2004, to stockholders of record on April 1, 2004.

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.

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 the 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 and increase in authorized shares approved on February 27, 2004, at the Annual Meeting of the Stockholders of the Company and to reflect the stock split distributed to stockholders on January 9, 2006.

**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 calculations in 2005 and 2004 takes into account certain shares that may be issued under the Non-Employee Directors' Deferred Compensation Plan (see Note 8).

| | Year ended September 30, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Numerator for primary and diluted earnings per share: | | | |
| Net income | $ 10,574,219 | $ 10,484,786 | $ 6,729,825 |
| Denominator: | | | |
| For basic earnings per share- weighted average shares (including for 2006, unissued vested directors' shares of 68,488) | 8,479,406 | 8,390,280 | 8,357,566 |
| Effect of potential diluted shares: Directors' deferred compensation shares | * | 59,958 | 100,036 |
| Denominator for diluted earnings per share-adjusted weighted average shares and potential shares | 8,479,406 | 8,450,238 | 8,457,602 |

* Not applicable - see Note 8.

The weighted average shares outstanding, potentially dilutive shares, and earnings per share for 2005 and 2004 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 2006, 2005 or 2004) 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 250,206 shares of the Company's common stock held by the plan as of September 30, 2006, 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 |
|---|---|---|
| 2006 | 11,643 | $209,700 |
| 2005 | 9,186 | $196,842 |
| 2004 | 20,116 | $173,125 |

## 8. Deferred Compensation Plan for Directors

Effective November 1, 1994, the Company formed the Panhandle Royalty Company 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, 2006, 70,581 shares (62,412 shares at September 30, 2005) 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, 2006 under the Plan was $1,202,569 ($1,335,305 at September 30, 2005). ($132,736), $1,111,097 and $344,551 was (credited) charged to the Company's results of operations for the years ended September 30, 2006, 2005 and 2004, 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 $17.20 per share at September 30, 2004 to $42.79 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 2006 and 2005 approximately 14% and 17%, respectively, of the Company's total revenues were derived from sales through Chesapeake Operating, Inc. During 2006 sales through JMA Energy Company accounted for approximately 11% of the Company's total revenues. During 2004 sales through Oneok, Inc. accounted for approximately 10% of the Company's total revenues.

## 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:

| | 2006 | 2005 |
|---|---|---|
| Producing properties | $ 103,129,158 | $ 84,388,067 |
| Non-producing properties | 11,273,373 | 11,170,926 |
| | 114,402,531 | 95,558,993 |
| Accumulated depreciation, depletion and amortization | (53,239,322) | (43,415,988) |
| Net capitalized costs | $ 61,163,209 | $ 52,143,005 |

### Costs Incurred

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

| | 2006 | 2005 (1) | 2004 |
|---|---|---|---|
| Property acquisition costs | $ 983,159 | $ 2,032,823 | $ 612,392 |
| Exploration costs | 2,719,068 | 907,385 | 1,239,217 |
| Development costs | 18,900,917 | 11,799,545 | 9,005,341 |
| | $ 22,603,144 | $ 14,739,753 | $ 10,856,950 |

(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 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, 2006, 2005 and 2004, have been estimated by Campbell & Associates, Inc., a consulting petroleum engineering firm. 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, 2006, 2005 and 2004. 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, 2003 | 836 | 28,270 | |
| | | | |
| Revisions of previous estimates | (50) | (2,489) | |
| Extensions and discoveries | 89 | 6,333 | |
| Production | (115) | (3,863) | |
| 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 | |

(1) The prices used to calculate reserves and future cash flows from reserves for oil and natural gas, respectively, were as follows: September 30, 2006 - $60.50, $3.49; 2005 - $64.18, $11.54. The large decrease in the natural gas price for 2006 resulted in a negative revision to gas reserves of 4,365 mmcf, meaning 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, 2003 | 703 | 23,600 | 133 | 4,670 |
| 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 |

The above reserve numbers exclude approximately 1.2 – 1.6 Bcf of $CO_2$ gas reserved for the years ended September 30, 2006, 2005, 2004 and 2003.

**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, 2006, 2005, 2004 were as follows: 2006 - $60.50, $3.49; 2005 - $64.18, $11.54; 2004 - $44.68, $5.42.

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Future cash inflows | $ 146,872,790 | $ 358,380,000 | $ 187,769,949 |
| Future production costs | 34,045,630 | 55,406,990 | 35,447,026 |
| Future development costs | 7,101,523 | 5,458,591 | 3,716,299 |
| Asset retirement obligation | 1,374,294 | 1,144,299 | 728,037 |
| Future net cash inflows before future income tax expenses | 104,351,343 | 296,370,120 | 147,878,587 |
| Future income tax expense | 24,394,272 | 84,708,027 | 40,959,776 |
| Future net cash flows | 79,957,071 | 211,662,093 | 106,918,811 |
| 10% annual discount | 28,765,504 | 78,040,774 | 37,768,822 |
| Standardized measure of discounted future net cash flows | $ 51,191,567 | $ 133,621,319 | $ 69,149,989 |

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

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

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Beginning of year | $ 133,621,319 | $ 69,149,989 | $ 53,740,536 |
| Changes resulting from: | | | |
| Sales of oil and gas, net of production costs | (30,745,693) | (25,439,615) | (19,480,491) |
| Net change in sales prices and production costs | (123,034,702) | 96,847,355 | 23,317,917 |
| Net change in future development costs | (1,053,612) | (1,142,715) | 91,349 |
| Net change in asset retirement obligation | (149,267) | (266,949) | (144,078) |
| Extensions and discoveries | 23,822,148 | 43,200,477 | 20,153,689 |
| Revisions of quantity estimates | (7,891,218) | (19,409,623) | (8,026,019) |
| Divestitures of reserves-in-place | - | (6,975,566) | - |
| Acquisition of reserves-in-place | - | 2,585,268 | - |
| Accretion of discount | 19,006,216 | 9,698,899 | 7,516,647 |
| Net change in income taxes | 39,908,385 | (28,601,833) | (6,413,806) |
| Change in timing and other, net | (2,292,009) | (6,024,368) | (1,605,755) |
| Net change | (82,429,752) | 64,471,330 | 15,409,453 |
| End of year | $ 51,191,567 | $133,621,319 | $69,149,989 |

## 11. Quarterly Results of Operations (Unaudited)

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

| | 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 |
| Basic earnings per share | $ 0.58 | $ 0.31 | $ 0.25 | $ 0.11 |
| Diluted earnings per share | $ 0.58 | $ 0.31 | $ 0.25 | $ 0.11 |

| | Fiscal 2005 | | | |
|---|---|---|---|---|
| | Quarter Ended | | | |
| | December 31 | March 31 | June 30 | September 30 |
| Revenues | $ 8,492,360 | $ 6,274,779 | $ 9,215,046 | $ 9,324,538 |
| Income before provision for income taxes | 3,616,344 | 2,210,649 | 5,056,419 | 4,192,374 |
| Net income | 2,448,344 | 1,575,649 | 3,419,419 | 3,041,374 |
| Basic earnings per share | $ 0.29 | $ 0.19 | $ 0.41 | $ 0.36 |
| Diluted earnings per share | $ 0.29 | $ 0.19 | $ 0.40 | $ 0.36 |

## 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 Co-President/COO and Co-President/CFO (Co-Presidents), 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 Co-Presidents 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 Co-Presidents, 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, 2006.

The Company management's assessment of the effectiveness of its internal controls over financial reporting as of September 30, 2006 has been audited by Ernst and Young, LLP, an independent registered public accounting firm, as stated in their report which is included in this report.

### (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 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 and to Form 10-QSB dated March 31, 1999).
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)
(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

No Form 8-K's were filed in the fourth quarter of fiscal 2006.

## 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 ROYALTY COMPANY

| | |
|---|---|
| By: /s/ Michael C. Coffman | By: /s/ Ben D. Hare |
| Michael C. Coffman | Ben D. Hare |
| Co-President | Co-President |
| Chief Financial Officer | Chief Operating Officer |

Date: December 12, 2006

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 | /s/ Bruce M. Bell |
| E. Chris Kauffman, Chairman of Board | Bruce M. Bell, Director |
| Date December 12, 2006 | Date December 12, 2006 |
| /s/ Robert A. Reece | /s/ Robert E. Robotti |
| Robert A. Reece, Director | Robert E. Robotti, Director |
| Date December 12, 2006 | Date December 12, 2006 |
| /s/ H. Grant Swartzwelder | /s/ Robert O. Lorenz |
| H. Grant Swartzwelder, Director | Robert O. Lorenz, Director |
| Date December 12, 2006 | Date December 12, 2006 |

/s/ Lonnie J. Lowry
Lonnie J. Lowry, Vice President,
Controller and Secretary
(Chief Accounting Officer)

Date December 12, 2006

2006
Annual
Report

PANHANDLE
ROYALTY COMPANY

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