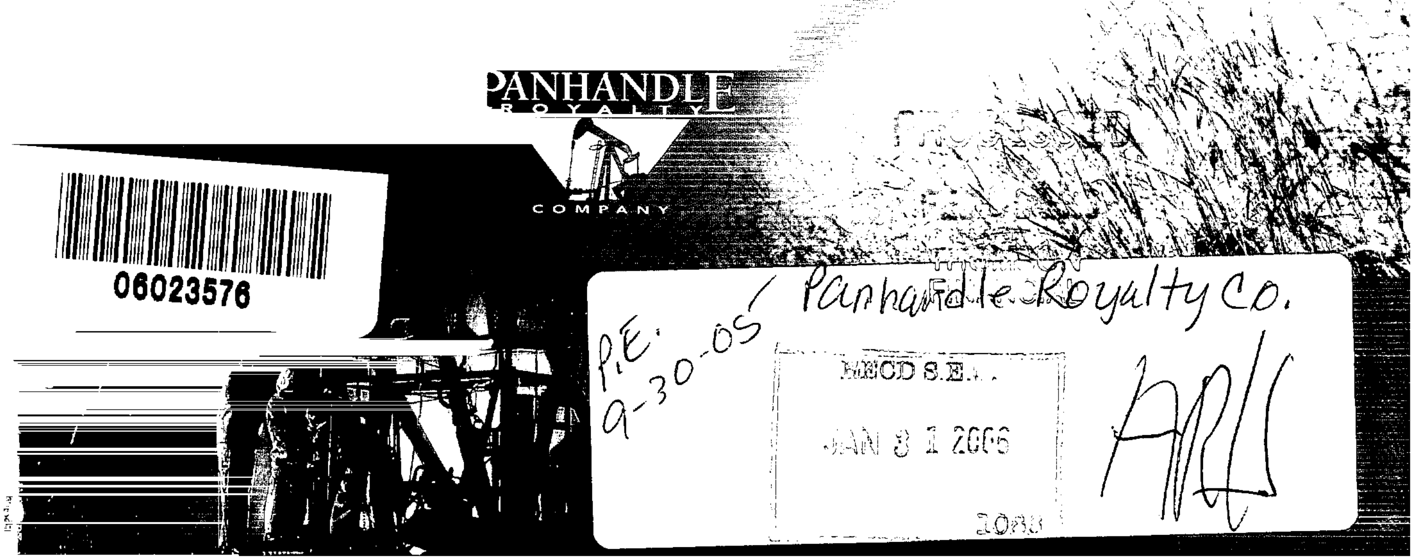
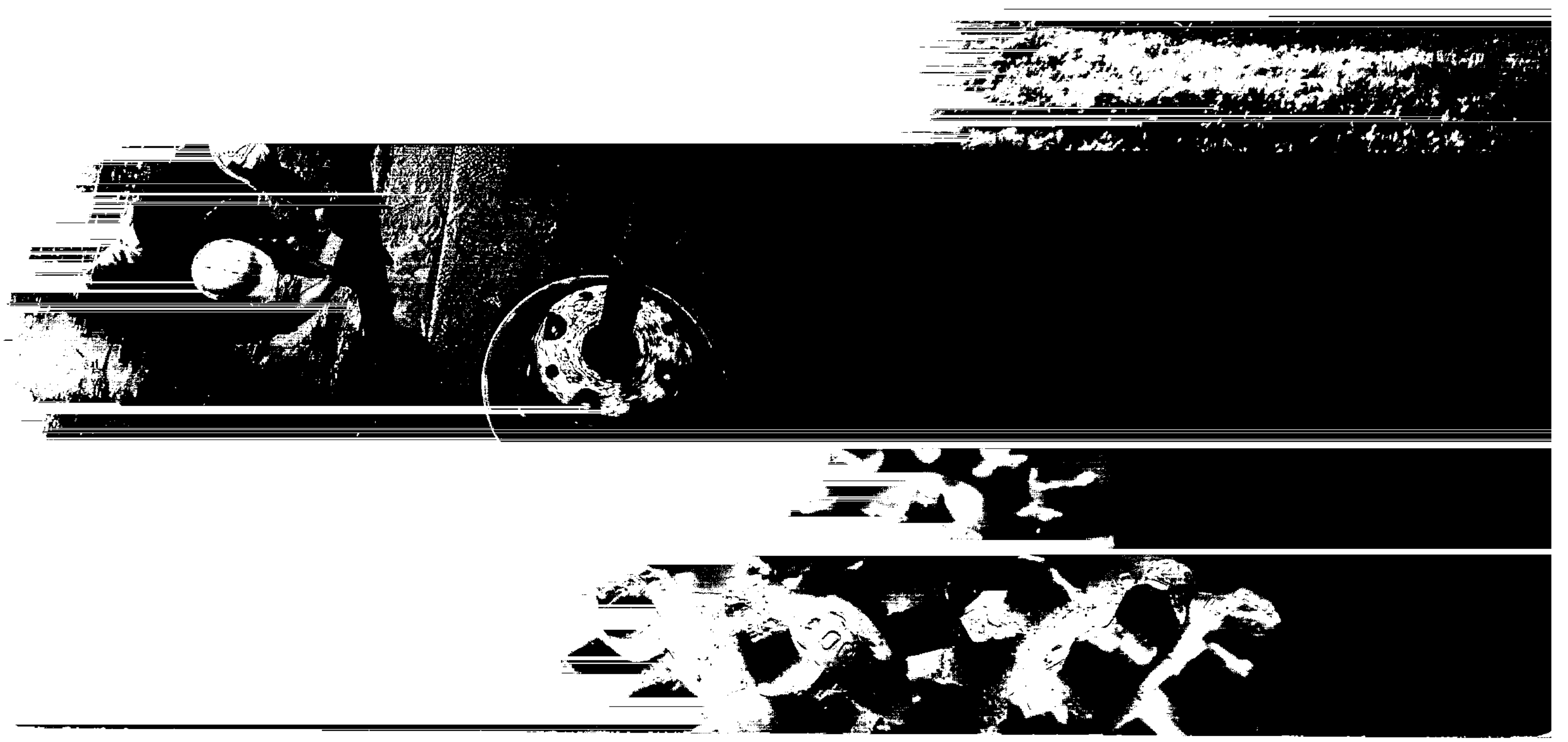
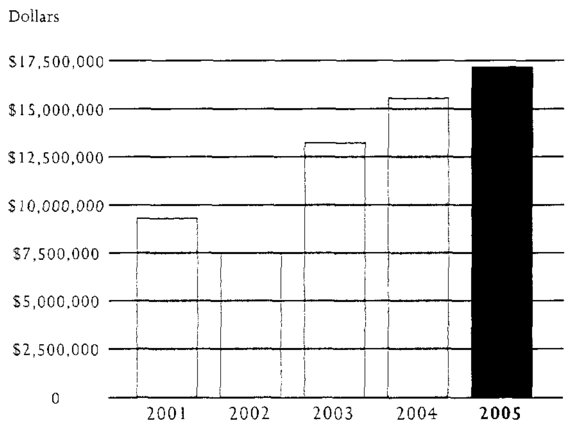
PANHANDLE
ROYALTY
COMPANY



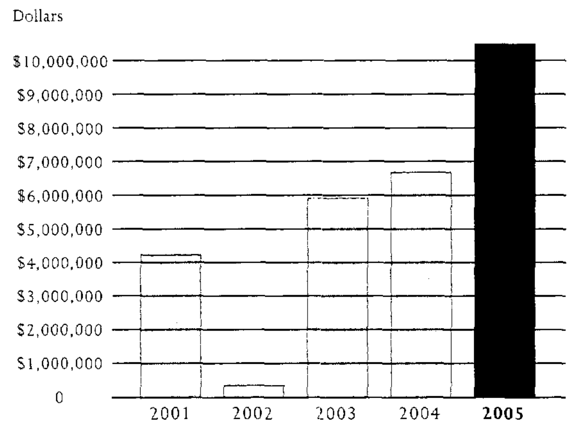
2005 ANNUAL REPORT



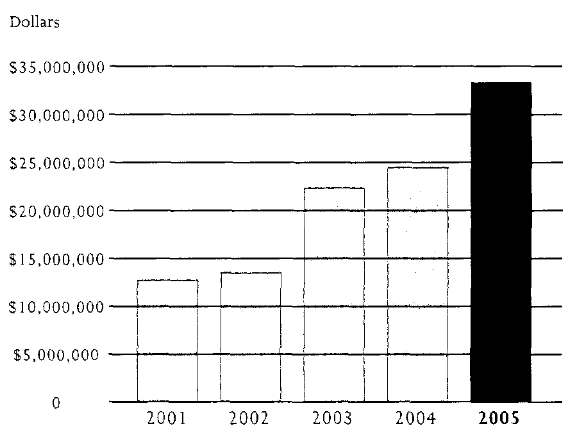
Cash Flow from Operations



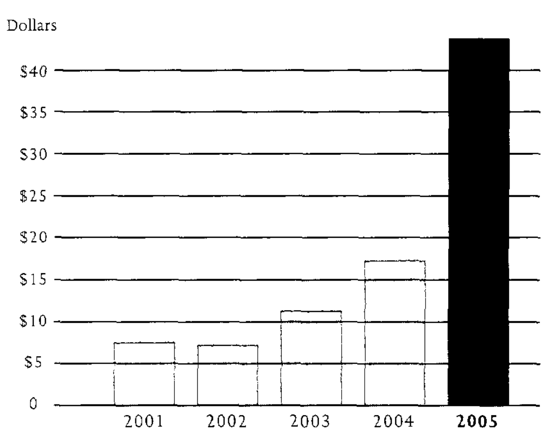
Net Income



Revenues

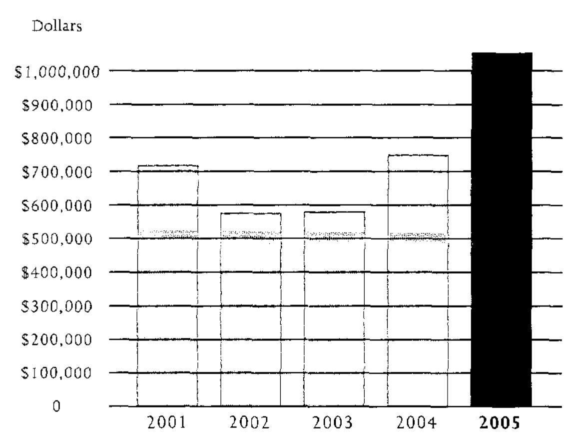


Stock Price at 9/30



The above prices are adjusted for a 3-for-1 stock split in May 1999 and a 2-for-1 stock split in April 2004.

Dividends Paid



PANHANDLE ROYALTY COMPANY

To Our Shareholders

In this report last year we remarked what an "exciting" year fiscal 2004 had been. In search of an adjective to indicate fiscal 2005 was considerably better than 2004, the only possibility seems to be "fabulous." To summarize highlights of our fabulous year, we have listed several of our accomplishments and expanding ongoing activities. Financially this was our third consecutive record setting fiscal year with revenues up 35.4% to $33,306,723 and net income up 55.8% to $10,484,876 or $2.48 per diluted share. Pretax income was $15,075,786 or an increase of 53.9%. Undiscounted estimated future cash flow from proven oil and gas reserves was up 100% to $296,860,830, while the 10% discounted amount was $190,395,273 or a 96% increase. Total assets rose 13% to $61,241,692, and shareholders equity climbed 34.6% to $38,635,350. Debt was more than cut in half ending the year at $5,166,657 after paying off $5,350,004.

The increase in revenue and reserve value was principally a function of oil and gas price with the average price received being $51.30 per barrel and $6.24 per mcf. Those were increases of 42.9% and 24.1% respectively. Due to hurricane Katrina, oil and gas price was abnormally high at September 30th and we were required by regulation to use those prices for valuing our reserves – they were $64.18 per barrel and $11.54 per mcf. Due to fiscal 2004's good results, a one-time special additional cash dividend was paid in March bringing our total per share dividend for the fiscal year to 25 cents or an increase of 39%. At $1,048,659 or 10% of net income, dividends for the first time exceeded $1,000,000.

E. Chris Kauffman

The shortage of drilling rigs, service equipment and experienced service personnel accounted for a healthy increase in individual well costs and expenses. Total costs and expenses were up 23.1% to $18,230,937. Excluding property acquisition costs, $12,706,930 was spent on new exploration and development well activity. This was an increase of 24% over fiscal 2004. We anticipate increasing that by another 36.5% to $17,350,000 in fiscal 2006. Average working interest in the 113 new working interest completions was 4.91%. Only six (6) of these were dry holes. There were an additional 157 royalty interest well completions including fourteen (14) dry holes. We have no cost in these royalty wells but their reserves do aid in reducing our overall finding cost which was $1.74 per mcf equivalent (excluding reserve revisions). Revenue from the higher oil and gas price, lease bonus monies and sale of some low income producing properties was utilized to pay all well costs and pay down the debt, while retaining over $1,000,000 cash at year end. Cash flow from operations grew 10.6% to $17,154,171. At year end we had a revenue interest in over 4,100 producing wells with an additional seventy-three (73) drilling or testing for completion. Approximately 83% of the oil and gas revenue is from natural gas wells with 77% of that derived from producers located in Oklahoma. About 25% of our oil and gas revenue is from royalty interest only wells. Most of our wells are situated upon some of the 258,884 net mineral acres owned in perpetual fee. The Company also held leases on an additional 20,023 net acres, an increase of 14.2% during the year.

We are not only increasing our volume of drilling and leases acquired but we have completed the first year and one-half of a five-year growth strategy to have an average working interest of 8% to 10% in wells completed each year by 2008-2009. As a non-operator this is the best method we believe available, with successful producing wells, to commence increasing reserves and to more rapidly increase production. Currently very few of our new wells are drilled as oil producers; hence oil production and oil reserves will probably continue their steady decline. We are increasing our natural gas production (3.8% increase in 2005) and proven producing reserves. The increased working interests are necessary to further expand natural gas production and show an overall increase on an mcf equivalent basis for total production and reserves. During fiscal 2005 several of our proven undeveloped reserve (PUD) wells were drilled and became proven producing reserves. Several others that were on our PUD list where we had not received a well proposal were removed because as a non-operator we had no certainty as to when they might be drilled by the operator.

In July we leased all of our approximate 9,000 net acres in 442 tracts located within the central Arkoma Basin of Arkansas. The $2,023,000 lease bonus at $227/acre made fiscal 2005 the largest lease revenue year in our history, when coupled with smaller size leases made elsewhere. The term of this lease is five (5) years with a 3/16 royalty interest and we retain the option on a well by well basis to participate with up to 50% of our interest when wells are proposed where we have 40 or more acres in the unit. An explanation of the geologic trend is found in the following operations section. Also, in the operations section is a description of several producing property divestitures which relieved us of most of our working interest in small income water floods and high water production, low oil production fields. Additionally we sold our approximately 1% working interest in the Gallegos Canyon Gas Field of northwestern New Mexico. In all cases we only sold our working interests, not our mineral interests, if any, in these properties. A total of $2,180,000 was received from these sales of over 800,000 mcf and some oil.

HW Peace II

This year we have elected to include the SEC Form 10-K in our Annual Report rather than utilize portions of it in a rewritten shortened form as in past years. The 10-K is essentially a complete financial statement with details and footnotes on all our activities exactly as we report it to the Securities and Exchange Commission. On the following pages before you get to the 10-K you will find non-financial information on our operations and land activities along with a profile of our largest shareholder and director, Bob Robotti.

Jerry Smith retired as Chairman of the Board in February and Chris Kauffman, who has been a board member fifteen (15) years, became the Chairman. Mr. Smith's board position was not filled and the size of the board was reduced from eight (8) to seven (7) directors.

This has been an extremely active and successful year for the Company, with the changes noted along with the completion of the review of financial reporting and internal controls required by the Sarbanes-Oxley Act. Panhandle completed its review with no significant or material deficiencies as indicated in Ernst & Young's letter. It is also a pleasure to announce the continued productivity increase by our employees to an average of $617,000 net income generated per employee from our seventeen-(17) person staff. We anticipate cash flow in fiscal 2006 to exceed all budgeted expenditures including amortizing debt payments of $166,000 per month at a 4.56% interest rate. However, should an acquisition on favorable terms present itself our considerable line-of-credit is available.

This will be my final annual report as President and CEO. The past almost fifteen (15) years have been the finest and most productive of my career. Panhandle has grown considerably, has excellent officers and employees and is extremely well positioned to have continued record years in the future. With our mineral and growing leasehold position in current active areas, and in other basins such as the Arkoma where new "unconventional" reservoirs are being tapped, Panhandle has a considerable potential for increased annual drilling. Some of the other "unconventional" basins where we own thousands of mineral acres are: the Williston Basin of North Dakota, the Tucumcari Basin and the NW shelf of the Permian Basin in New Mexico. My retirement date is set as March 1, 2006. It has been fun.

E. Chris Kauffman
Chairman

HW Peace II
President & Chief Executive Officer

Profile of a Stockholder – Excellent Advice Leads to More than Two Decades of Sound Investments

Bob Robotti discovered the benefit of having a well-informed mentor 21 years ago. That's when Joe Reilly, a founder of the Tweedy, Browne Company, a long-standing private investment firm that specializes in small, inactively traded securities, recommended that Bob purchase stock in Panhandle Royalty Company.

Since that piece of advice proved extremely sound, Bob continued to follow it. Today, this lifelong New Yorker owns 5.6 percent of PRC.

A member of Panhandle's board of directors since 2004, Bob describes the company as extremely well run. "It's conservatively managed and has a relatively unique set of assets: mineral ownership," he explains. "These mineral interests provide significant potential. They are also a perpetual asset in an industry of finite assets."

"Historically it's been good – but in the current energy environment it's particularly great – to be a mineral owner. Minerals are clearly a scarce resource in the oil and gas business. This ownership interest uniquely positions Panhandle to participate in exploration opportunities that others won't get the chance to see. Most other oil and gas companies have to conduct their own exploration, which means those companies have to develop exploration leads and secure land before they can begin to explore. Our minerals bring the best explorers to us."

Robert E. Robotti

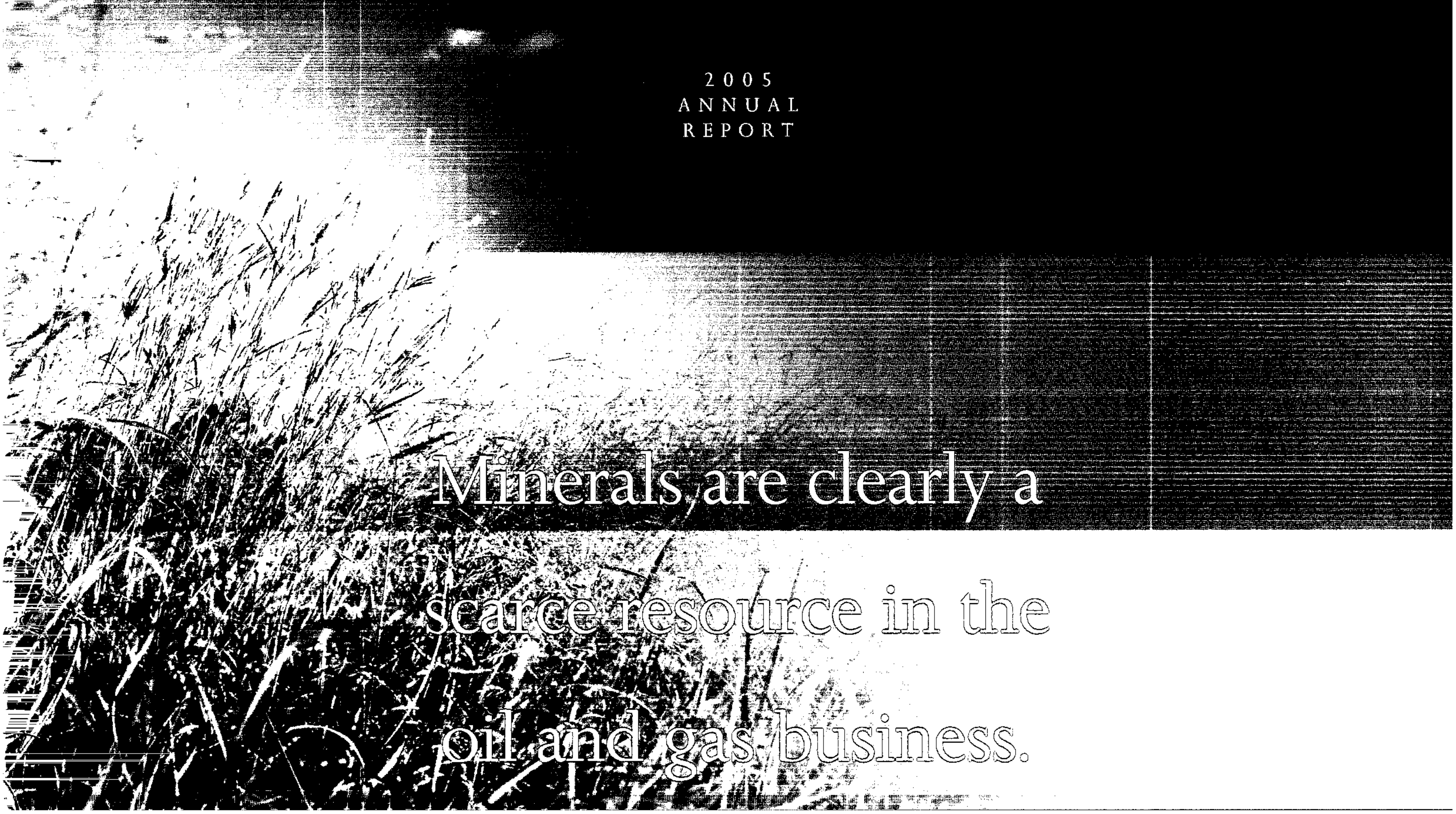
Founder and largest shareholder of Robotti & Company – which began as Robotti & Eng in 1983 – Bob is extremely familiar with the energy business. Robotti & Company specializes in investing in the securities of energy companies like Panhandle Royalty Company. As a result, his description of PRC as a company that is different than most energy organizations comes from a position of extensive experience and deep knowledge about the industry.

In addition, as a member of Panhandle's Audit Committee, Bob is well situated to judge the soundness of both the company and its operations. He describes PRC's corporate governance as extremely strong and its Audit Committee as excellent. A member of the SEC Advisory Committee for Small Cap Companies, Bob says that although PRC is smaller than the average company, its governance is as strong as any. Bob believes PRC was based on a sound business concept and has since benefited from wise leadership.

"I recognize what a great package the original incorporators put together," he says. "I am convinced the oil and gas industry is going to beat a path to our door because they're going to want to explore on our minerals. Due to wise management, we are perfectly positioned to harvest this opportunity. We have the in-house capability to evaluate these opportunities, the willingness to participate and the financial strength to commit capital. Fortunately, the company broadened its focus in the early 90s when, instead of just being a mineral owner that collects royalty checks (not that there's anything bad about that), it began to reinvest cash flow to seize these opportunities. A timely and great use of capital, that reinvestment has enabled us to get the most out of our assets and position us today."

Bob says energy producers have gotten very good at developing and producing known reserves, but he is convinced exploration is going to take on greater importance.

"We now have an excellent opportunity to get great returns on our earlier reinvestments," he says. "Companies are going to step out to develop new exploration leads and will need to lease our minerals in the process. Since these exploration minerals aren't currently committed to others, we'll have the ability to participate on a larger basis in these upcoming opportunities. We've also got an inside track on important information: who's interested in drilling, where they want to drill and what the prospects are in the area. All of this places us in a very real and very exciting position of strength for the future."



2005
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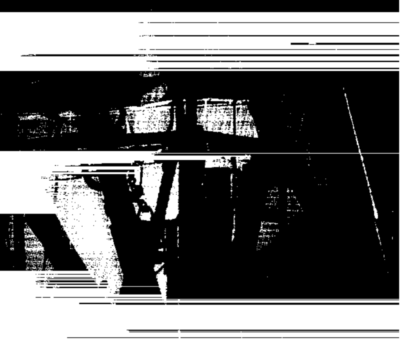
Minerals are clearly a scarce resource in the oil and gas business.

This ownership interest uniquely positions Panhandle to participate in exploration opportunities that others won't get the chance to see.



Financial And Operating Highlights

	2005	2004	2003
Revenue and Earnings			
Revenue	$33,306,723	$24,606,609	$22,456,038
Net income	$10,484,786	$6,729,825	$5,961,622
Diluted earnings per share	$2.48	$1.59	$1.42
Average diluted shares outstanding	4,225,119	4,228,801	4,207,426
Net cash provided by operating activities	$17,154,171	$15,515,300	$13,198,368
Capital expenditures	$14,741,636	$10,946,471	$9,195,916
Exploration and Production			
Total proved reserves (mcf equivalent)	31,252,341	32,812,205	33,285,723
Estimated future net cash flow from reserves (before income taxes):			
Undiscounted	$296,860,830	$148,192,749	$115,741,342
Discounted @ 10%	$190,395,273	$97,212,618	$75,497,304
Percent of reserves natural gas	88%	86%	84%
Total production (mcf equivalent)	4,620,712	4,553,193	4,602,600
Average gas price ($/mcf)	$6.24	$5.03	$4.79
Average oil price ($/barrel)	$51.30	$35.89	$29.30
Average price per mcf equivalent	$6.54	$5.18	$4.80
Average production costs ($/mcfe)	$1.04	$0.90	$0.87
Finding and development costs ($/mcfe), excluding revisions	$1.74	$1.49	$1.36

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

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

Operations Highlights

Fiscal Year 2005 was an eventful and successful year for Panhandle Royalty Company and was characterized by the divestiture of several under-performing or non-core assets; the leasing of a major mineral lease block in Arkansas; and the acquisition of significantly larger working interests in two projects.

In northern Arkansas, we successfully conducted an "auction" which resulted in the leasing of approximately 9,000 mineral acres, for a $2 million bonus payment. At our Dill City Prospect in Washita County, OK, we acquired an 80% Working Interest in two producing wells and approximately 1,300 acres with future drilling potential. The Dempsey Prospect, located in Roger Mills County, OK, is the focus of an active Cottage Grove/Tonkawa oil drilling program. We purchased a 25% Working Interest (19.25% Net Revenue Interest) in one well drilled and completed in 2005, plus a 25% Working Interest in at least two additional locations. All of these activities will be discussed in detail in this report.

As has been the case for the last few years, FY2005 was an active drilling year, spurred by high commodity prices and demand for natural gas. During the year we reviewed 219 proposals for drilling, with 110 approved for working interest participation. It is a significant advantage to the Company to have our mineral and leasehold base to allow us to screen this many opportunities and to pick and choose those in which to invest.

During FY2005, we participated in the drilling of 142 Working Interest wells and had a Royalty Interest in 201 non-participating wells drilled. This compares with 172 Working Interest wells and 146 Royalty Interest wells in 2004. The completed Working Interest wells resulted in 9 oil producers, 98 gas producers, and 6 dry holes. The completed Royalty Interest wells accounted for 12 oil wells, 131 gas wells, and 14 dry holes.

Working Interest

Category	2005	2004	2003
Drilling	11	18	12
Testing	18	32	24
Producing	107 (9 oil, 98 gas)	107 (14 oil, 3 gas)	113 (11 oil, 102 gas)
Dry Holes	6	15	20
Totals	142	172	169

Royalty Interest

Category	2005	2004	2003
Drilling	14	5	3
Testing	30	23	21
Producing	143 (12 oil, 131 gas)	112 (16 oil, 96 gas)	114 (14 oil, 100 gas)
Dry Holes	14	6	12
Totals	201	146	150

We purchased 1,336 acres of new non-producing leasehold in 2005 and 1,361 acres of producing leasehold at a total cost of $1,825,638. Mineral acres acquired amounted to 74 acres at a cost of $141,000 ($1,905/acre). These acreage acquisitions continued to be in active plays in which we are involved and expect drilling activity in the near future.

Actual dollars spent on exploration, development, and land acquisition in FY2005 was approximately $14,740,000 (See Note 9, Notes to Consolidated Financial Statements). In FY2004, Panhandle spent $10,857,000 on exploration, development, and property acquisition.

Divestitures

As mentioned in the introduction, FY2005 was a year in which we took steps to divest or monetize several under-performing or non-core assets. Some of the more significant divestitures are summarized in the Table below. Within the divested water floods, we retained our mineral interests outside of the producing formations.

LOCATION	FY2005 DIVESTITURES	NET $ RECEIVED
SAN JUAN, NM	GALLEGOS CANYON	755,000
SOUTHERN OK	VARIOUS WATERFLOODS	611,000
SEMINOLE, OK	NE WEWOKA DEWATERING	151,000
OSAGE, OK	SULLIVAN OSAGE	202,000
	TOTAL	1,719,000

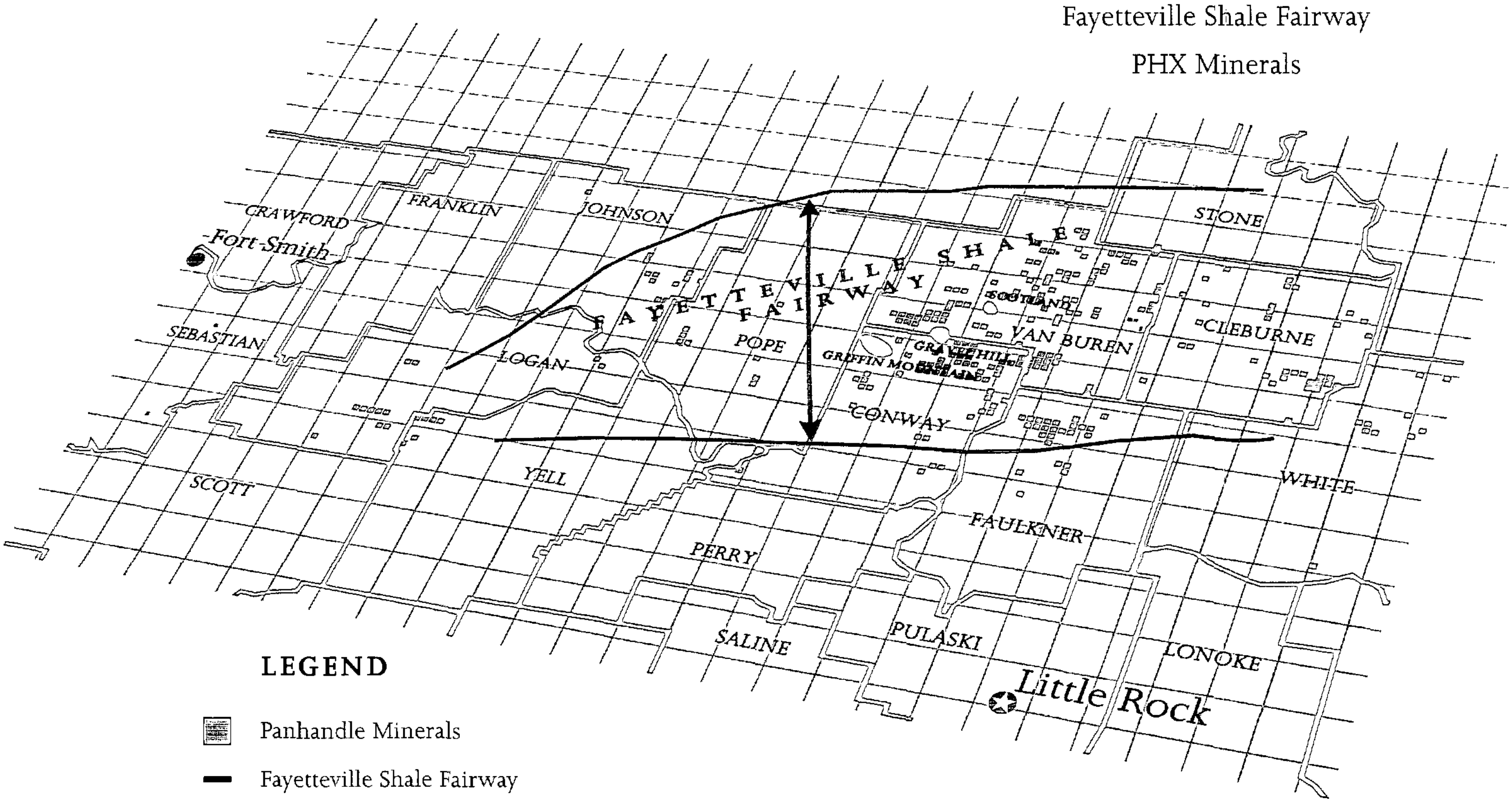
Northern Arkansas Minerals

In the Lower 48 of the United States, there are several active non-conventional plays underway. They include the Barnett Shale of the Fort Worth Basin and the Bakken Shale of the Williston Basin. In 2005, activity began to develop in the Arkoma Basin of Arkansas in a formation called the Fayetteville Shale. As of 9/30/05, approximately 50 wells have been drilled in the main area of this play with Initial Potential Tests ranging from 200 MCFGD to 3,700 MCFGD and cumulative production from 23 wells totaling 209 million cubic feet of gas (IHS Energy estimate). Following expressions of interest from several parties, Panhandle conducted an auction in May, 2005, receiving bids from five companies. As a result, we were able to lease approximately 9,000 mineral acres for a total bonus of $2,023,000.

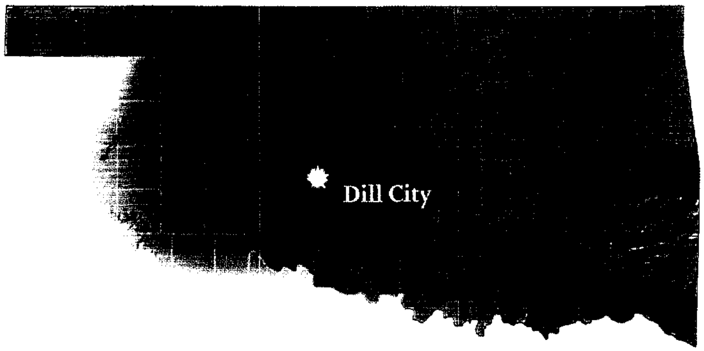
Arkansas-Arkoma Basin

Fayetteville Shale Fairway

PHX Minerals



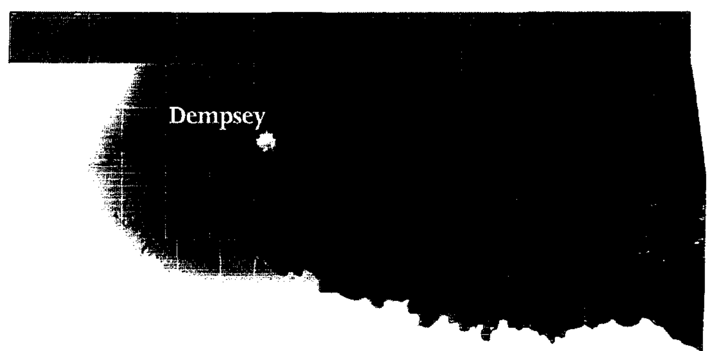
Dill City Prospect - Washita County, OK



In December, 2004, the Company closed an acquisition in Washita County, OK. As a result of the acquisition, Panhandle acquired an 80% interest in two producing wells in Washita County plus an 80% interest in approximately 1,360 undeveloped acres in two sections in the Dill City Prospect at a cost of $878,000.

Subsequently, we were able to interest another company in reimbursing us $260,000 for our acreage costs; committing to drill two additional wells; and carrying us to casing point for 15% of our Working Interest costs in the first two wells. The first of these wells, the Johnson 1-1 (42.5% Working Interest), commenced operations in late September, 2005, reached total depth in late October, 2005 and was testing at the time of this report. In addition, the two companies formed a ten-section Area of Mutual Interest for future acreage acquisition and drilling.

Dempsey Area - Roger Mills County, OK



In 2005, Panhandle participated in the drilling of the Hartman 2-35 well in Roger Mills County. The well tested oil from perforations in the Cottage Grove and Tonkawa Formations at rates in excess of 500 BOPD. The well has been producing at about 220-400 BOPD for several months. Panhandle has a 2.8% Net Revenue Interest in the well.

Following the Hartman well, the Company participated with a 4.5% Net Revenue Interest in the drilling of the Hattie1-4, one mile to the southwest of the Hartman. That well had Initial Potential Tests of over 400 BOPD from the Cottage Grove and Tonkawa Formations.

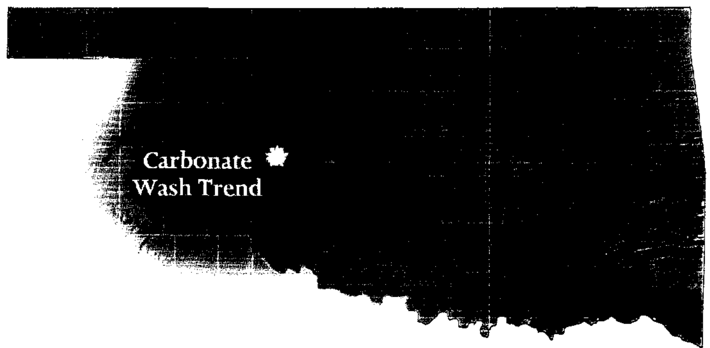
The Company exercised an opportunity to purchase acreage and take a 25% Working Interest in the Juanita Emmit #1. That well, two miles southeast of the Hartman, was completed in September, 2005 with Initial Potential Tests of over 400 BOPD. Panhandle has a 19.25% Net Revenue Interest in the Juanita Emmit production. We expect at least two offsets to the Juanita Emmit to be proposed.

In addition, we have approved participation in the Hall 1-35(in the same section as the Hartman) but it had not commenced at the time of this report. The Company has approximately a 2.3% Working and Net Revenue Interest. If this field is ultimately developed on an 80-acre pattern, several additional locations in which the Company has an interest could be drilled.

Carbonate Wash Trend - Roger Mills County, OK

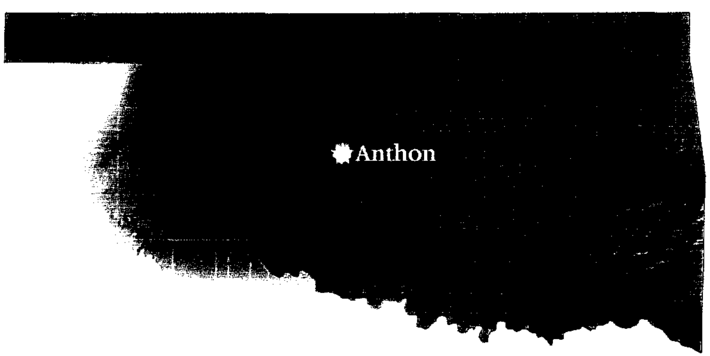
This is our most active drilling area with 2005 year end results consisting of 25 successful producers, six drilling and testing, and seven scheduled to be drilled. This includes both Working and Royalty Interest Wells. In one section we have six successful wells with one, the Hutson Farms 6-18 flowing at rates in excess of 6.0 MMCFGD (7.4% NRI). In another section we have six producing wells with a seventh scheduled to be drilled.

The Company has 1,386 acres of leasehold and 1,405 mineral acres in this trend, which should sustain drilling operations for the future.



Anthon Area - Custer County, OK

In FY 2005, we drilled one dry hole and one producer in this trend. At year end, there were two wells drilling or testing. This activity was generated by our Hatcher 1-1 discovery in 2004 which our engineering analysis indicated to have 4.0 BCFG gross reserves (187 MMCFG net). The Company has minerals and leasehold in 6 sections of the prospect with an average working interest of 5.5%.



A shallower play appears to be developing in this same area and if successful, could result in future development drilling. Two wells in which the Company has a working interest (5.375%) have encountered this zone and appear to be productive. The Abbott 1-35, originally completed in the deeper zone, was subsequently completed in the shallower zone also. The commingled initial rate for the Abbot is approximately 3.0 MMCFGD and 154 BOPD.

Other Areas

Panhandle continues to be active in a number of other areas such as the Mayfield Area of Beckham County, OK. The Company participated in 12 successful gas wells at Mayfield in FY2005. In addition, proposals were received in Arkansas, Texas, New Mexico and Kansas in which the Company either participated or had a Royalty Interest.

State of Oklahoma index map image prepared by "Ray Sterner/Applied Physics Laboratory/The Johns Hopkins University, licensed by North Star Science and Technology, LLC"

PANHANDLE ROYALTY COMPANY

Board of Directors

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

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

Robert O. Lorenz
Retired
(1) (2)

H W Peace II
President and
Chief Executive Officer

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

Officers

H W Peace II
President and
Chief Executive Officer

Michael C. Coffman
Vice President
Chief Financial Officer
Secretary and Treasurer

Ben D. Hare
Vice President
Chief Operating Officer

Ben Spriestersbach
Vice President, Land

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

Form 10-K
A copy of the annual report to the Securities and Exchange Commission on Form 10-K is included with this report.

Company Contact Information
Phone: (405) 948-1560
Fax: (405) 948-1063
www.panra.com
5400 N. Grand Blvd.
Suite 305
Oklahoma City, OK 73112

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

FORM 10-K

Annual Report under Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended September 30, 2005

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 whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act during the past 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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. { }

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
X Yes _No

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange 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, 2005, was $100,025,465. As of December 3, 2005, 4,205,443 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 in February 2006, 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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Certain defined terms as used in this report: "**SEC**" means the United States Securities and Exchange Commission, "**Bbl**" means barrel, "**Mcf**" means thousand cubic feet, "**Mcfd**" means thousand cubic feet per day, "**Mcfe**" means natural gas stated on an Mcf basis and crude oil converted to a thousand cubic feet of natural gas equivalent by using the ratio of one Bbl of crude oil to six Mcf of natural gas, "**PV-10**" means estimated pretax present value of future net revenues discounted at 10% using SEC rules, "**gross**" wells or acres are the wells or acres in which the Company has a working interest, and "**net**" wells or acres are determined by multiplying gross wells or acres by the Company's net revenue interest in such wells or acres. References to years 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.

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 of the Company 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 of the Company to 12,000,000 shares and to split the shares on a two-for-one basis.

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 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 nineteen 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 thus acquiring most of its New Mexico mineral acreage.

On October 1, 2001, Panhandle acquired privately held Wood Oil Company ("Wood") of Tulsa, Oklahoma. Pursuant to an Agreement and Plan of Merger dated August 9, 2001 among Panhandle Royalty Company, PHC, Inc., and Wood, Wood merged with Panhandle's wholly owned subsidiary PHC, Inc., on October 1, 2001, with Wood being the surviving company. 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 interests in producing wells, both working interests and royalty interests, are centered in Oklahoma with some activity in New Mexico, Texas 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. This "increased density" drilling has accounted for a large part of the successful oil and gas wells completed during these years and has added significant reserves and production for the Company. The Company acquired additional mineral interest properties, both producing and non-producing, and interests in approximately 2,000 wells in the Wood acquisition. Several of the mineral properties and well interests were in areas where the Company had no holdings, thus expanding the Company's area of interest.

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 are generally located in and service the areas where the Company's producing wells are located. The Company does not act as operator for any of the properties in which it owns an interest; thus 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 has not, to date, engaged in price hedging on its oil or gas production.

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 and these mineral properties 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 in 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 varied 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 2005, sales through Chesapeake Operating Inc. accounted for approximately 17% 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, especially in the current market environment for natural gas and oil. 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 which may be 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 1980s and the individual pipeline restructuring proceedings of the early to mid-1990s, interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, FERC expanded the impact of open access regulations to intrastate commerce.

More recently, FERC has pursued other policy initiatives that have affected natural gas marketing. Most notable are (1) 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, 2005, Panhandle employed seventeen persons on a full-time basis and one part-time employee. Four of the employees are executive officers and the chief executive officer is a director of the Company.

RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating the Company's business and future prospects. The risk factors described below are not necessarily exhaustive and investors are encouraged to perform their own investigation with respect to the Company and its business. Investors should also read the other information included 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 are likely to 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 other 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 involving oil and natural gas properties 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 can not 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, 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, thus reserves and production will decline materially from their current levels.

The rate of production from oil and natural gas properties generally declines as reserves are depleted. 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, the Company's proved reserves will decline materially as reserves are produced. Future oil and natural gas production is, therefore, highly dependent upon the level of success in acquiring or finding additional reserves. All the above activities must be done in conjunction with operators of these wells, 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. We rely 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 them 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 these 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 of, or shortages or delays in the 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 encountering well blowouts, cratering and explosions, pipe failures, fires, formations with 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 us 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 costs not covered by insurance that could have a material adverse effect upon financial reports.

We can not 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 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 and qualified personnel 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 profit margin, cash flow and operating results or restrict the ability to drill wells and conduct ordinary operations.

ITEM 2 PROPERTIES

As of September 30, 2005, Panhandle's principal properties consisted of perpetual ownership of 258,884 net mineral acres, held principally in tracts in Oklahoma, New Mexico and Texas and 19 other states. The Company also held leases on 20,023 net acres of minerals primarily in Oklahoma. At September 30, 2005, Panhandle held small royalty and/or working interests in 4,163 producing oil or gas wells, and 73 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 warrant 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, 2005, 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	10,050	44,596	1,074	2,856	8,976	41,740		
Colorado	8,326	39,299	109	219	31	200	8,186	38,880
Florida	6,421	13,849					6,421	13,849
Illinois	1,068	4,979	40	261			1,028	4,718
Kansas	3,082	11,816	152	1,280			2,930	10,536
Montana	1,007	17,947					1,007	17,947
Nebraska	1,319	13,249					1,319	13,249
North Dakota	11,179	64,286					11,179	64,286
New Mexico	57,396	174,460	1,367	7,195			56,029	167,265
Oklahoma	113,119	939,927	30,553	252,889	4,176	29,497	78,390	657,541
South Dakota	1,825	9,300					1,825	9,300
Texas	43,186	361,270	11,063	105,079	856	4,600	31,267	251,591
OTHER	906	6,112					906	6,112
Total:	258,884	1,701,090	44,358	369,779	14,039	76,037	200,487	1,255,274

(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
		2006	2007	2008	
Kansas	2,117				2,117
Oklahoma	16,218	623	932	931	13,732
Texas	316				316
Other	1,372				1,372
TOTAL	20,023	623	932	931	17,537

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 and drill and operate producing wells, it is not feasible or possible to provide estimates of all proved undeveloped reserves and associated future net revenues. The Company is currently providing proved undeveloped reserve estimates for wells that it has a substantial reason to believe will be drilled in the very near term. In 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, 2005	613,536	24,011,062
September 30, 2004	710,513	24,086,120
September 30, 2003	703,400	23,599,473
Proved Undeveloped Reserves		
September 30, 2005	20,787	3,435,341
September 30, 2004	49,729	4,164,633
September 30, 2003	132,575	4,670,400
Total Proved Reserves		
September 30, 2005	634,323	27,446,403
September 30, 2004	760,242	28,250,753
September 30, 2003	835,975	28,269,873

These reserves exclude approximately 1.2 to 1.5 MMcf 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 year-end prices to future production of proved reserves less estimated future expenditures (based on costs as of year end) to be incurred with respect to the development and production of such reserves. Such pricing is based on SEC guidelines. No federal income taxes are included in estimated costs. However, the amounts are net of operating costs and production taxes levied by respective states. Prices used for determining future cash flows from oil and natural gas for the periods ended September 30, 2005, 2004, 2003 were as follows: 2005 - $64.18, $11.54; 2004 - $44.68, $5.42; 2003 - $27.39, $4.43. 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)

	9-30-05	9-30-04	9-30-03
Proved Developed	$ 265,189,328	$ 129,410,259	$ 97,847,582
Proved Undeveloped	$ 31,671,502	$ 18,782,490	$ 17,893,760
Total Proved	$ 296,860,830	$ 148,192,749	$ 115,741,342

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

	9-30-05	9-30-04	9-30-03
Proved Developed	$ 169,417,252	$ 84,400,194	$ 63,591,623
Proved Undeveloped	$ 20,978,021	$ 12,812,424	$ 11,905,681
Total Proved	$ 190,395,273	$ 97,212,618	$ 75,497,304

The future net cash flows are net of immaterial amounts of future cash flow to be received from CO2 reserves.

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 9-30-05	Year Ended 9-30-04	Year Ended 9-30-03
Bbls - Oil	101,581	114,986	112,746
Mcf - Gas	4,011,226	3,863,277	3,926,124
Mcfe	4,620,712	4,553,193	4,602,600

Gas production includes 183,743, 176,605 and 152,384 Mcf of CO2 sold at average prices of $.51, $.41 and $.32 per Mcf for the years ended September 30, 2005, 2004 and 2003, 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 9-30-05	Year Ended 9-30-04	Year Ended 9-30-03
Per Bbl, Oil	$ 51.30	$ 35.89	$ 29.30
Per Mcf, Gas	$ 6.24	$ 5.03	$ 4.79
Per Mcfe	$ 6.54	$ 5.18	$ 4.80
Average Production (lifting costs)			
(Per Mcfe of Gas)			
(1)	$ 0.52	$ 0.48	$ 0.46
(2)	$ 0.52	$ 0.42	$ 0.41
	$ 1.04	$ 0.90	$ 0.87

(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 27% of the Company's oil and gas revenue is generated from small royalty interests in a few thousand wells. These royalty interests bear no share of the operating costs on those producing wells.

GROSS AND NET PRODUCTIVE WELLS AND DEVELOPED ACRES

The following table sets forth Panhandle's gross and net productive oil and gas wells as of September 30, 2005. Panhandle owns fractional royalty interests or fractional working interests in these wells. The Company does not operate any wells.

	Gross Wells	Net Wells
Oil	1,131	21.21
Gas	3,032	71.61
TOTAL	4,163	92.82

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

As of September 30, 2005, Panhandle owned 369,779 gross developed mineral acres and 44,358 net developed mineral acres. Panhandle has also leased from others 177,324 gross developed acres, which contain 17,537 net developed acres.

UNDEVELOPED ACREAGE

As of September 30, 2005, Panhandle owned 1,331,311 gross and 214,526 net undeveloped mineral acres, and leases on 34,012 gross and 2,486 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 ending September 30, 2003	4.986539	0.462544
Fiscal year ending September 30, 2004	4.362204	0.322523
Fiscal year ending September 30, 2005	5.485356	0.142047
Exploratory Wells		
Fiscal year ending September 30, 2003	1.117805	0.541950
Fiscal year ending September 30, 2004	1.245048	0.305172
Fiscal year ending September 30, 2005	0.584992	0.131758
Purchased Wells		
Fiscal year ending September 30, 2003	0.113069	0
Fiscal year ending September 30, 2004	0.009749	0
Fiscal year ending September 30, 2005	1.660737	0

PRESENT ACTIVITIES

The following table sets forth the gross and net oil and gas wells drilling or testing as of September 30, 2005, in which Panhandle owns a royalty or working interest. These wells are not yet producing.

	Gross Wells	Net Wells
Oil	14	0.2211
Gas	59	1.2236

OTHER FACILITIES

The Company leases 8,189 square feet of office space in Oklahoma City, OK. The obligation under this lease will end in 2008.

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 2006 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 flow 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/or natural gas; current 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/or 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 may 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 or the oil and natural gas industry in general.

ITEM 3 LEGAL PROCEEDINGS

There were no material legal proceedings involving Panhandle or its subsidiary 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, 2005.

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 2-for-1 stock split, effective on April 16, 2004):

Quarter Ended	High	Low
December 31, 2003	$ 15.68	$ 10.94
March 31, 2004	$ 19.35	$ 13.22
June 30, 2004	$ 19.27	$ 14.31
September 30, 2004	$ 17.80	$ 14.76
December 31, 2004	$ 25.30	$ 17.39
March 31, 2005	$ 31.68	$ 21.10
June 30, 2005	$ 30.50	$ 21.05
September 30, 2005	$ 45.00	$ 27.75

As of December 3, 2005, there were 1,929 holders of record of Panhandle's Class A Common Stock.

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

Date	Rate Per Share
December 2003	$0.04
March 2004	$0.04
June 2004	$0.05
September 2004	$0.05
December 2004	$0.05
March 2005	$0.10
June 2005	$0.05
September 2005	$0.05

The Company's line of credit loan agreement contains a provision limiting the paying or declaring of a cash dividend to fifty percent of cash flow, as defined, 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,				
	2005 (A)	2004 (A)	2003 (A)	2002 (A)	2001
Revenues					
Oil & Gas Sales	$ 30,242,210	$ 23,578,615	$ 22,098,198	$ 13,080,754	$ 12,546,055
Lease Bonuses	2,214,992	115,938	72,765	41,497	17,991
Interest & Other	849,521	912,056	285,075	469,146	231,876
	$ 33,306,723	$ 24,606,609	$ 22,456,038	$ 13,591,397	$ 12,795,922
Costs and Expenses					
Lease Oper. Exp. & Prod. Taxes	$ 4,802,595	$ 4,098,124	$ 4,013,572	$ 3,001,449	$ 1,771,789
Exploration Costs (B)	784,741	236,939	469,224	417,971	947,046
Depr. Depl. Amortization	7,506,571	6,115,500	5,783,457	5,845,779	1,670,961
Provision for Impairment	232,295	841,687	692,220	1,116,234	848,535
Gen. & Administrative	4,545,208	3,033,437	2,666,177	2,263,908	1,689,426
Interest Expense	359,527	488,097	699,266	895,997	779
	$ 18,230,937	$ 14,813,784	$ 14,323,916	$ 13,541,338	$ 6,928,536
Income Before Provision (Benefit) For Income Taxes	$ 15,075,786	$ 9,792,825	$ 8,132,122	$ 50,059	$ 5,867,386
Cumulative effect of accounting changes, net of taxes of $28,500 (C)	-	-	46,500	-	-
Provision (Benefit) for Income Taxes	4,591,000	3,063,000	2,217,000	(293,000)	1,600,000
Net Income	$ 10,484,786	$ 6,729,825	$ 5,961,622	$ 343,059	$ 4,267,386
Diluted Earnings per share	$ 2.48	$ 1.59	$ 1.42	$ 0.08	$ 1.02
Dividends Declared per share	$ 0.25	$ 0.18	$ 0.14	$ 0.14	$ 0.18
Weighted Average Shares Outstanding					
Basic	4,195,140	4,178,783	4,162,744	4,135,744	4,120,218
Diluted	4,225,119	4,228,801	4,207,426	4,179,944	4,170,088
Net Cash Proved by Operating Activities	$ 17,154,171	$ 15,515,300	$ 13,198,368	$ 7,481,195	$ 9,302,965
Total Assets	$ 61,241,692	$ 54,186,362	$ 49,402,534	$ 44,837,060	$ 25,279,684
Long-Term Debt	$ 3,166,653	$ 8,516,657	$ 12,666,661	$ 14,024,000	$ 4,050,000
Shareholders Equity	$ 38,635,350	$ 28,700,515	$ 22,527,685	$ 16,953,294	$ 16,995,050

All share and per share amounts are adjusted for the effect of the 2-for-1 stock split, effective on April 16, 2004.

(A) 2002, 2003, 2004 and 2005 results included are consolidated amounts of Panhandle Royalty Company and its wholly owned subsidiary Wood Oil Company, acquired October 1, 2001.

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

(C) 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 for a complete discussion.

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. Such 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. The recent and continuing increase in oil and gas prices have provided and should continue to provide increased drilling opportunities, which should then translate into increased production volumes for the Company.

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

	For the Year Ended September 30,				
	2005	Percent Incr or (Decr)	2004	Percent Incr or (Decr)	2003
Production:					
Oil (Bbls)	101,581	(12%)	114,986	2%	112,746
Gas (Mcf)	4,011,226	4%	3,863,277	(2%)	3,926,124
Average Sales Price:					
Oil (per Bbl)	$ 51.30	43%	$ 35.89	22%	$ 29.30
Gas (per Mcf)	$ 6.24	24%	$ 5.03	5%	$ 4.79

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. It currently appears oil and gas sales prices will remain at these or increased levels for at least the next year. In addition, the Company was able to increase lease bonus revenue by approximately $2,100,000 in 2005, 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 chart. 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 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 is expected to 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 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 two 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 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.

Liquidity and Capital Resources

At September 30, 2005, the Company had positive working capital of $3,470,006 as compared to $1,941,634 at September 30, 2004. Cash at September 30, 2005 amounted to $1,638,833. The increase in working capital and cash at September 30, 2005 compared to September 30, 2004 was the result of increased oil and gas sales revenues during 2005 which is the Company's primary source of cash. Cash flow from operating activities increased 11% to $17,154,171 for fiscal 2005, as compared to fiscal 2004, primarily due to the increase in oil and gas sales prices.

Capital expenditures for oil and gas activities (primarily drilling and equipment costs on wells) for 2005 was $14,741,636, as compared to $10,946,471 for 2004. The Company has historically funded its capital expenditures, overhead costs and dividend payments from operating cash flow. Due to the increased capital expenditure level in 2005, the Company borrowed, from time to time, on its revolving bank loan to help fund those expenditures. However, as a result of increased cash flow from higher prices received for natural gas and oil in 2005, the Company was able to reduce its bank debt by a net of $5,350,004.

The Company expects to moderately increase its capital expenditure level in 2006. Funds for capital expenditures are expected to come from cash flow and bank debt, if needed. Approximately $15 million is available under the Company's current bank debt facility for capital expenditures and acquisitions. Further, the credit facility could be increased, if needed, for a large acquisition. Cash flow from oil and gas sales is expected to increase in 2006 as average oil and gas sales prices for 2006 currently are expected to exceed 2005 levels. Thus, the Company expects to generate cash flow in excess of expected budgeted needs. However, unexpected declines in oil or natural gas sales prices would significantly reduce cash flow.

Contractual Obligations

The Company has a credit facility with BancFirst, Oklahoma City, Oklahoma. The facility consists of a term loan of $10,000,000 and a revolving loan of $15,000,000 which is subject to a semi-annual borrowing base determination. The current borrowing base under the facility is $22,500,000. The term loan matures on April 1, 2008, and the revolving loan matures on March 31, 2007. Monthly payments on the term loan are $166,667, plus accrued interest, beginning on May 1, 2003. Borrowings under the revolving loan are due at maturity. Interest on the term loan is fixed at 4.56% until maturity. The revolving loan bears interest at the national prime rate minus ¾% (6% at September 30, 2005) or LIBOR (for one, three or six month periods), plus 1.80%. At September 30, 2005, the Company had no balance outstanding under this facility.

Total outstanding borrowings under both the term loan and the revolving line of credit may not exceed the borrowing base, which was $22.5 million at September 30, 2005. Subsequent 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 of treasury stock. Other covenants require the Company to maintain certain financial ratios. At September 30, 2005, the Company was in compliance with the covenants.

The table below summarizes the Company's contractual obligations as of September 30, 2005:

	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	$ 5,166,657	$ 2,000,004	$ 3,166,653	$ -	$ -

2004 Compared to 2003

Overview

The Company recorded net income of $6,729,825 in 2004, compared to net income of $5,961,622 in 2003. Total revenues were larger as a result of increased oil and gas sales revenues generated by increases in the average sales prices of oil and natural gas in 2004 as compared to 2003. It currently appears oil and gas sales prices will remain at the levels seen in 2004, or even slightly increased, for at least the next year.

Revenues

Total revenues increased 10% to $24,606,609 in 2004 compared to $22,456,038 in 2003. The increase was due to increases in the average sales price for oil and natural gas in 2004. Production volumes were basically flat in 2004 compared to 2003. New production from the Company's drilling activity almost replaced the normal production decline of existing gas wells, thus, gas production declined only 2%. Oil wells beginning production in 2004 replaced the decline of existing oil well production, and increased oil production 2%.

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 and normal inflation of costs. Gross production taxes are paid as a percentage of oil and gas sales revenues and therefore increased in 2004 to $1,505,213, an increase of $39,574 over 2003.

Exploration Costs

Exploration costs decreased $232,285 or 50% in 2004 as compared to 2003. 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.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased $332,043 or 6% in 2004 as compared to 2003. The increase was due to several new wells, with large cost basis, going on production in 2004 and having high initial production rates. These production rates and the large cost basis resulted in the increase in DD&A.

Provision for Impairment

The provision for impairment increased $149,467 or 22% in 2004 as compared to 2003. This increase was the result of the fair values of several older fields being reduced along with several individual wells, which were completed and began production in 2004. These wells had a fair value at year-end less than their carrying value as their initial production rates were substantially less than expected.

General and Administrative Costs (G&A)

G&A costs increased $367,260 or 14% in 2004. Personnel related expenses (including salaries, payroll taxes, insurance and ESOP expenses) increased approximately $203,000 in 2004. G&A expense related to the Non-Employee Directors Deferred Compensation Plan (the "Plan") increased approximately $130,000 in 2004. The increase resulted from the Company recognizing a charge to G&A to adjust the potential shares in the Plan to market price at September 30, 2004. 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.

Interest Expense

Interest expense decreased $211,169 or 30% in 2004. The decrease was due to lower average outstanding debt balances during 2004.

Provision for Income Taxes

The provision for income taxes increased in 2004 due to increased income before taxes (as discussed above). The Company was able to continue utilizing excess percentage depletion on its oil and gas properties to reduce its tax liability and its effective tax rate from federal and state statutory rates. The effective tax rate was approximately 31% in 2004, 27% in 2003, while a tax benefit was provided in 2002.

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 can not 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 several thousand 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 matters.

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 2005 production, a $.10 per Mcf change in the price received for natural gas production would result in a corresponding $401,000 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 $101,500 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 revolving credit facility which bears interest at an annual variable interest rate equal to either the national prime rate minus ¾% or LIBOR for one, three or six month periods, plus 1.8%. However, at September 30, 2005, the Company had no balance outstanding under this facility. The Company has a $10,000,000 term loan with an outstanding balance of $5,166,657 at September 30, 2005 maturing on April 1, 2008. The interest rate is fixed at 4.56% until maturity.

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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, 2005. 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, 2005, the Company's internal control over financial reporting was effective based on those criteria.

The Company's independent registered public accounting firm, Ernst and Young, LLP, has audited our assessment of the effectiveness of the Company's internal control over financial reporting as of September 30, 2005, 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, 2005, 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, 2005, 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, 2005, 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, 2005 and 2004, and the related consolidated statements of income, stockholders' equity and cash flows for each of the three years in the period ended September 30, 2005 and our report dated December 9, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 9, 2005

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, 2005 and 2004, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2005. 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, 2005 and 2004, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2005, 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, 2005, 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 9, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 9, 2005

Panhandle Royalty Company
Consolidated Balance Sheets

	September 30, 2005	September 30, 2004
Assets		
Current Assets:		
Cash and cash equivalents	$ 1,638,833	$ 642,343
Oil and gas sales receivables	6,641,447	4,962,992
Income tax and other receivables	21,520	239,895
Total current assets	8,301,800	5,845,230
Property and equipment at cost, based on successful efforts accounting:		
Producing oil and gas properties	85,393,626	74,928,073
Non-producing oil and gas properties	10,165,367	9,790,377
Furniture and fixtures	524,721	471,564
	96,083,714	85,190,014
Less accumulated depreciation, depletion, and amortization	43,787,403	37,755,438
Net properties and equipment	52,296,311	47,434,576
Investment in partnerships, at equity	396,424	659,399
Other	247,157	247,157
Total assets	$ 61,241,692	$ 54,186,362

(Continued on next page)

See accompanying notes.

Panhandle Royalty Company
Consolidated Balance Sheets

	September 30, 2005	September 30, 2004
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts payable	$ 700,242	$ 825,941
Accrued liabilities:		
Deferred compensation	1,335,305	864,333
Interest	23,129	30,936
Other	173,445	182,382
Income taxes payable	599,669	-
Long-term debt due within one year	2,000,004	2,000,004
Total current liabilities	4,831,794	3,903,596
Long-term debt	3,166,653	8,516,657
Deferred income taxes	13,321,750	12,249,000
Asset retirement obligation and other noncurrent liabilities	1,286,145	816,594
Stockholders' equity:		
Class A voting common stock, $.0166 par value; 12,000,000 shares authorized, 4,205,443 issued and outstanding (4,189,783 in 2004)	70,091	69,830
Capital in excess of par value	1,785,297	1,286,850
Retained earnings	36,779,962	27,343,835
Total stockholders' equity	38,635,350	28,700,515
Total liabilities and stockholders' equity	$ 61,241,692	$ 54,186,362

See accompanying notes.

Panhandle Royalty Company
Consolidated Statements of Income

	Year ended September 30, 2005	2004	2003
Revenues:			
Oil and gas sales	$ 30,242,210	$ 23,578,615	$ 22,098,198
Lease bonuses and rentals	2,214,992	115,938	72,765
Gain on sales and interest	454,348	5,436	13,580
Income from partnerships	395,173	906,620	271,495
	33,306,723	24,606,609	22,456,038
Costs and expenses:			
Lease operating expenses and production taxes	4,802,595	4,098,124	4,013,572
Exploration costs	784,741	236,939	469,224
Depreciation, depletion, and amortization	7,506,571	6,115,500	5,783,457
Provision for impairment	232,295	841,687	692,220
General and administrative	4,545,208	3,033,437	2,666,177
Interest expense	359,527	488,097	699,266
	18,230,937	14,813,784	14,323,916
Income before provision for income taxes and cumulative effect of accounting change	15,075,786	9,792,825	8,132,122
Provision for income taxes	4,591,000	3,063,000	2,217,000
Net income before cumulative effect of accounting change	10,484,786	6,729,825	5,915,122
Cumulative effect of accounting changes, net of taxes of $28,500	-	-	46,500
Net Income	$ 10,484,786	$ 6,729,825	$ 5,961,622
Basic earnings per common share:			
Income before cumulative effect of accounting change	$2.50	$ 1.61	$ 1.42
Cumulative effect of accounting change	-	-	0.01
Net income	$ 2.50	$ 1.61	$ 1.43
Diluted earnings per common share:			
Income before cumulative effect of accounting change	$ 2.48	$ 1.59	$ 1.41
Cumulative effect of accounting change	-	-	0.01
Net income	$ 2.48	$ 1.59	$ 1.42

See accompanying notes.

Panhandle Royalty Company
Consolidated Statements of Stockholders' Equity

	Common Stock		Capital in Excess of	Retained	
	Shares	Amount	Par Value	Earnings	Total
Balances at September 30, 2002	4,158,846	$ 69,314	$ 896,643	$ 15,987,337	$ 16,953,294
Purchases and cancellation of common shares	(108)	(2)	(776)	-	(778)
Issuance of common shares to ESOP	13,284	222	152,676	-	152,898
Issuance of common shares to directors for services	6,180	103	43,343	-	43,446
Dividends declared ($.14 per share)	-	-	-	(582,797)	(582,797)
Net Income	-	-	-	5,961,622	5,961,622
Balances at September 30, 2003	4,178,202	$ 69,637	$ 1,091,886	$ 21,366,162	$ 22,527,685
Issuance of common shares to ESOP	10,058	168	172,830	-	172,998
Issuance of common shares to directors for services	1,523	25	22,134	-	22,159
Dividends declared ($.18 per share)	-	-	-	(752,152)	(752,152)
Net Income	-	-	-	6,729,825	6,729,825
Balances at September 30, 2004	4,189,783	$ 69,830	$ 1,286,850	$ 27,343,835	$ 28,700,515
Issuance of common shares to ESOP	4,593	77	196,457	-	196,534
Issuance of common shares to directors for services	11,067	184	301,990	-	302,174
Dividends declared ($.25 per share)	-	-	-	(1,048,659)	(1,048,659)
Net Income	-	-	-	10,484,786	10,484,786
Balances at September 30, 2005	4,205,443	$ 70,091	$ 1,785,297	$ 36,779,962	$ 38,635,350

See accompanying notes.

Panhandle Royalty Company
Consolidated Statements of Cash Flows

	Year ended September 30,		
	2005	2004	2003
Operating Activities			
Net income	$ 10,484,786	$ 6,729,825	$ 5,961,622
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of accounting change	-	-	(46,500)
Depreciation, depletion, amortization, and impairment	7,738,866	6,957,186	6,475,677
Deferred income taxes	1,072,750	1,920,000	1,676,000
Lease bonus income	(1,985,067)	288,028	67,673
Exploration costs	784,741	236,939	469,224
Gain on sale of assets	(365,288)	(6,959)	(38,378)
Equity in earnings of partnerships	(395,173)	(246,573)	(133,836)
Common stock issued to Employee Stock Ownership Plan/Directors for Services	498,708	195,156	152,898
Cash provided (used) by changes in assets and liabilities			
Oil and gas sales and other receivables	(1,678,455)	(1,121,476)	(1,456,628)
Prepaid expenses and other	(2,249)	96,893	(111,713)
Accounts payable and accrued liabilities	328,530	669,422	61,604
Income taxes payable	672,022	(203,141)	120,725
Total adjustments	6,669,385	8,785,475	7,236,746
Net cash provided by operating activities	17,154,171	15,515,300	13,198,368
Investing Activities			
Capital expenditures, including dry hole costs	(14,741,637)	(10,946,471)	(9,195,916)
Proceeds from leasing of fee mineral acreage	2,304,383	-	-
Distributions received from partnerships	497,839	369,761	252,856
Investment in partnerships	-	-	(45,000)
Proceeds from sale of assets	2,180,397	12,903	76,772
Net cash used in investing activities	$ (9,759,018)	$ (10,563,807)	$ (8,911,288)

(Continued on next page)

See accompanying notes.

Panhandle Royalty Company
Consolidated Statements of Cash Flows (continued)

	Year ended September 30,		
	2005	2004	2003
Financing Activities			
Borrowings under debt agreement	$ 11,350,000	$ 6,825,000	$ 1,525,000
Payments of loan principal	(16,700,004)	(10,975,004)	(4,878,335)
Purchase and cancellation of common shares	-	-	(778)
Payments of dividends	(1,048,659)	(752,152)	(582,797)
Net cash provided by (used in) financing activities	(6,398,663)	(4,902,156)	(3,936,910)
Increase (decrease) in cash and cash equivalents	996,490	49,337	350,170
Cash and cash equivalents at beginning of year	642,343	593,006	242,836
Cash and cash equivalents at end of year	$ 1,638,833	$ 642,343	$ 593,006

Supplemental Disclosures of Cash Flow Information

Interest paid	$ 367,333	$ 496,441	$ 727,153
Income taxes paid, net of refunds received	$ 2,668,870	$ 1,344,321	$ 456,338

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 located 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.

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.

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.

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. This causes 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 and subsequent rapid decline rates of new wells.

1. Summary of Significant Accounting Policies (continued)

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, 2005 and 2004, 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, 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.

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 $6,152,783 at September 30, 2005, 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 79 year life of the Company. There are approximately 220,000 acres of non-producing minerals in approximately 7,500 tracts owned by the Company. Thus on average tracts contain 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

1. Summary of Significant Accounting Policies (continued)

ownership of the fee mineral acres as an ownership basis. There continues to be significant drilling activity each year on these minerals. 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 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 $232,295, $841,687 and $692,220 respectively, for 2005, 2004 and 2003. The majority of the impairment recognized in these years 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.

Asset Retirement Obligations

On October 1, 2002 the Company adopted Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets. 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 under FAS 143 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 ending September 30, 2005 relating to the Company's retirement obligation for plugging liability:

	Plugging Liability
Plugging Liability October 1, 2004	$ 602,979
Accretion of Discount	46,812
Liability Incurred in the Period	82,494
Revision of Plugging Estimate	412,014
Plugging Liability September 30, 2005	$ 1,144,299

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, 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 during the year. Diluted EPS is similar to basic EPS except that the weighted average common shares outstanding is increased 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 Deferred Compensation Plan for Outside Directors (the "Plan"). Compensation cost is recognized for the requisite directors' fees as earned and unissued stock is added to each director's account based on the closing price of the stock at the date earned. The unissued shares and compensation costs are then adjusted for changes in the shares market value subsequent to the date of grant until the conversion date (see Note 8), due to a conversion to cash feature in the Plan.

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, prepaid expenses, accounts payable, and accrued liabilities approximate their fair values due to the short maturity of these instruments. The fair value of Company's long-term debt approximates its carrying amount due to the interest rate on the Company's term-loan being a fixed rate, which is approximately equivalent to market rates at September 30, 2005 for similar type debt based on the Company's credit worthiness.

The Company has not entered into hedging contracts on its oil and/or gas production in the past. However, going forward the Company may consider entering into hedging contracts if price risk mitigation is considered to be advantageous.

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.

2. Commitments

The Company leases office space in Oklahoma City, Oklahoma under the terms of an operating lease expiring in April, 2008. Future minimum rental payments under the terms of the lease are $146,144 in 2006, $146,144 in 2007 and $48,715 in 2008. Total rent expense incurred by the Company was $158,203 in 2005, $115,192 in 2004 and $127,156 in 2003.

3. Income Taxes

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

	2005	2004	2003
Current:			
Federal	$ 3,488,250	$ 1,113,000	$ 521,000
State	30,000	30,000	20,000
	3,518,250	1,143,000	541,000
Deferred:			
Federal	1,004,750	1,851,000	1,607,000
State	68,000	69,000	69,000
	1,072,750	1,920,000	1,676,000
	$ 4,591,000	$ 3,063,000	$ 2,217,000

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:

	2005	2004	2003
Provision for income taxes at statutory rate	$ 5,178,799	$ 3,329,561	$ 2,762,324
Percentage depletion	(620,982)	(334,365)	(653,947)
Tight-sands gas credits	-	-	(20,000)
State income taxes, net of federal benefit	63,700	64,350	57,850
Other	(30,517)	3,454	70,773
	$ 4,591,000	$ 3,063,000	$ 2,217,000

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

	2005	2004
Deferred tax liabilities:		
Financial basis in excess of tax basis, including intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$ 13,933,416	$ 12,843,000
Deferred tax assets:		
Percentage depletion and alternative minimum tax credit, and state net operating loss carry forwards	220,340	233,000
Financial charges which are deferred for tax purposes	391,326	361,000
	611,666	594,000
Net deferred tax liabilities	$ 13,321,750	$ 12,249,000

4. Long-term Debt

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

	2005	2004
Revolving line of credit	$ -	$ 3,350,000
Term loan	5,166,657	7,166,661
	5,166,657	10,516,661
Current maturities of long-term debt	2,000,004	2,000,004
	$ 3,166,653	$ 8,516,657

In February 2005, the Company amended its Loan Agreement with BancFirst of Oklahoma City, Oklahoma. The Agreement consists of a term loan in the amount of $10,000,000 and a revolving loan in the amount of $15,000,000 which is subject to a semi-annual borrowing base determination. The current borrowing base under the Agreement is $22,500,000. The term loan matures on April 1, 2008, and the revolving loan matures on March 31, 2007. Monthly payments on the term loan are $166,667, plus accrued interest. Borrowings under the revolving loan are due at maturity. Interest on the term loan is fixed at 4.56% until maturity. The revolving loan bears interest at the national prime rate minus ¾% (6.0% at September 30, 2005) or LIBOR (for one, three or six month periods), plus 1.80%. The Company, at September 30, 2005, had no balance outstanding under the revolving loan.

The total outstanding borrowings under both the term loan and the revolving line of credit may not exceed the borrowing base, which is $22.5 million as of September 30, 2005. Subsequent 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 of treasury stock, and require the Company to maintain certain financial ratios. At September 30, 2005 the Company was in compliance with the covenants.

The amounts of required principal payments for the next five years as of September 30, 2005, are as follows: 2006-$2,000,004, 2007-$2,000,004 and 2008-$1,166,649.

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.

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.

6. Earnings Per Share

The following table sets forth the computation of basic and diluted earnings per share. The Company's diluted earnings per share calculation takes into account certain shares that may be issued under the Non-Employee Directors' Deferred Compensation Plan (see Note 7).

	Year ended September 30,		
	2005	2004	2003
Numerator for primary and diluted earnings per share:			
Net income	$ 10,484,786	$ 6,729,825	$ 5,961,622
Denominator:			
For basic earnings per share-weighted average shares	4,195,140	4,178,783	4,162,744
Effect of potential diluted shares:			
Directors' deferred compensation shares	29,979	50,018	44,682
Denominator for diluted earnings per share-adjusted weighted average shares and potential shares	4,225,119	4,228,801	4,207,426

The weighted average shares outstanding, potentially dilutive shares, and earnings per share for 2003 have been restated to affect the 2-for-1 stock split 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 2005, 2004 or 2003) 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 205,490 shares of the Company's common stock held by the plan as of September 30, 2005, 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
2005	4,593	$ 196,842
2004	10,058	$ 173,125
2003	13,822	$ 156,978

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 current Plan contains an option allowing the directors to convert the shares to cash upon separation from the Company the liability is 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 will be either issued to the director or may be 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, 2005, 31,206 shares (50,251 shares at September 30, 2004) are included in the Plan. The Company has accrued $1,335,305 at September 30, 2005 ($864,333 at September 30, 2004) in connection with the Plan ($1,111,097, $344,551 and $241,673 was charged to the results of operations for the years ended September 30, 2005, 2004 and 2003, 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.

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 will eliminate the requirement to adjust the deferred compensation liability for changes in the market value of the Company's common stock. This change will reduce volatility in the Company's earnings resulting from the charges to expense caused by market value changes in the Company's common stock. The deferred compensation liability at the date of the Plan's amendment will be reclassified into stockholders' equity.

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 2004 and 2003 approximately 10% and 14%, respectively, of the Company's total revenues were derived from gas sales to ONEOK, Inc. During 2005 sales through Chesapeake Operating Inc. accounted for approximately 17% of the Company's total revenues.

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:

	2005	2004
Producing properties	$ 85,393,626 (1)	$ 74,928,073
Non-producing properties	10,165,367	9,790,377
	95,558,993	84,718,450
Accumulated depreciation, depletion and amortization	(43,415,988)	(37,424,995)
Net capitalized costs	$ 52,143,005	$ 47,293,455

(1) Includes cost of $1,005,559 on exploratory wells which were drilling and/or testing at September 30, 2005.

Costs Incurred

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

	2005 (1)	2004	2003
Property acquisition costs	$ 2,032,823	$ 612,392	$ 127,058
Exploration costs	907,385	1,239,217	1,412,653
Development costs	11,799,545	9,005,341	7,818,988
	$ 14,739,753	$ 10,856,950	$ 9,358,699

(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.

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, 2005, 2004 and 2003, 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, 2005, 2004 and 2003. 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.

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

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, 2002	1,115	28,116
Revisions of previous estimates	(289)	(1,953)
Extensions and discoveries	123	6,033
Production	(113)	(3,926)
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

	Proved Developed Reserves		Proved Undeveloped Reserves	
	Oil (Mbarrels)	Gas (MMcf)	Oil (Mbarrels)	Gas (MMcf)
September 30, 2002	821	22,896	294	5,220
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

The above reserve numbers exclude approximately 1.2 – 1.5 MMcf of CO_2 gas reserved for the years ended September 30, 2005, 2004, 2003 and 2002.

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

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.

	2005	2004	2003
Future cash inflows	$ 358,380,000	$ 187,769,949	$ 148,633,837
Future production costs	55,406,990	35,447,026	29,036,188
Future development costs	5,458,591	3,716,299	3,856,341
Asset retirement obligation	1,144,299	728,037	508,362
Future net cash inflows before future income tax expenses	296,370,120	147,878,587	115,232,946
Future income tax expense	84,708,027	40,959,776	31,554,746
Future net cash flows	211,662,093	106,918,811	83,678,200
10% annual discount	78,040,774	37,768,822	29,937,664
Standardized measure of discounted future net cash flows	$ 133,621,319	$ 69,149,989	$ 53,740,536

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

	2005	2004	2003
Beginning of year	$ 69,149,989	$ 53,740,536	$ 43,944,947
Changes resulting from:			
Sales of oil and gas, net of production costs	(25,439,615)	(19,480,491)	(18,084,626)
Net change in sales prices and production costs	96,847,355	23,317,917	20,300,852
Net change in future development costs	(1,142,715)	91,349	87,405
Net change in asset retirement obligation	(266,949)	(144,078)	(331,601)
Extensions and discoveries	43,200,477	20,153,689	15,315,189
Revisions of quantity estimates	(19,409,623)	(8,026,019)	(8,291,358)
Divestitures of reserves-in-place	(6,975,566)	-	-
Acquisition of reserves-in-place	2,585,268	-	-
Accretion of discount	9,698,899	7,516,647	6,135,420
Net change in income taxes	(28,601,833)	(6,413,806)	(4,032,361)
Change in timing and other, net	(6,024,368)	(1,605,755)	(1,303,331)
Net change	64,471,330	15,409,453	9,795,589
End of year	$133,621,319	$ 69,149,989	$ 53,740,536

11. Quarterly Results of Operations (Unaudited)

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

	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	0.58	0.38	0.81	0.72
Diluted earnings per share	$ 0.58	$ 0.37	$ 0.81	$ 0.72

	Fiscal 2004			
	Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 4,973,462	$ 6,184,605	$ 6,809,770	$ 6,638,772
Income before provision for income taxes	1,402,233	2,705,868	3,374,484	2,310,240
Net income	990,233	1,897,637	2,130,484	1,711,471
Basic earnings per share	0.24	0.45	0.51	0.41
Diluted earnings per share	$ 0.24	$ 0.45	$ 0.50	$ 0.40

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

NONE

ITEM 9A CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The Company maintains "disclosure controls and procedures," as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. The Company's disclosure controls and procedures have been designed to meet, and management believes that they do meet, reasonable assurance standards. Based on their evaluation as of the end of the fiscal period covered by this report, the Chief Executive Officer and Chief Financial Officer have concluded that, subject to the limitations noted above, the Company's disclosure controls and procedures were effective 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 Chief Executive Officer and Chief Financial Officer, 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, 2005.

The Company management's assessment of the effectiveness of its internal controls over financial reporting as of September 30, 2005 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 Panhandle Royalty Company's definitive proxy statement, which will be filed with the Securities and Exchange Commission 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

(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)

(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 2005.

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/ H W Peace II
H W Peace II, Chief
Executive Officer,
President, Director
(Principal Executive Officer)

Date: December 13, 2005

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

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

Date December 13, 2005

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

Date December 13, 2005

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

Date December 13, 2005

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

Date December 13, 2005

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

Date December 13, 2005

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

Date December 13, 2005

/s/ Michael C. Coffman
Michael C. Coffman, Vice President
Treasurer and Secretary (Principal Financial and
Accounting Officer)

Date December 13, 2005

Notes

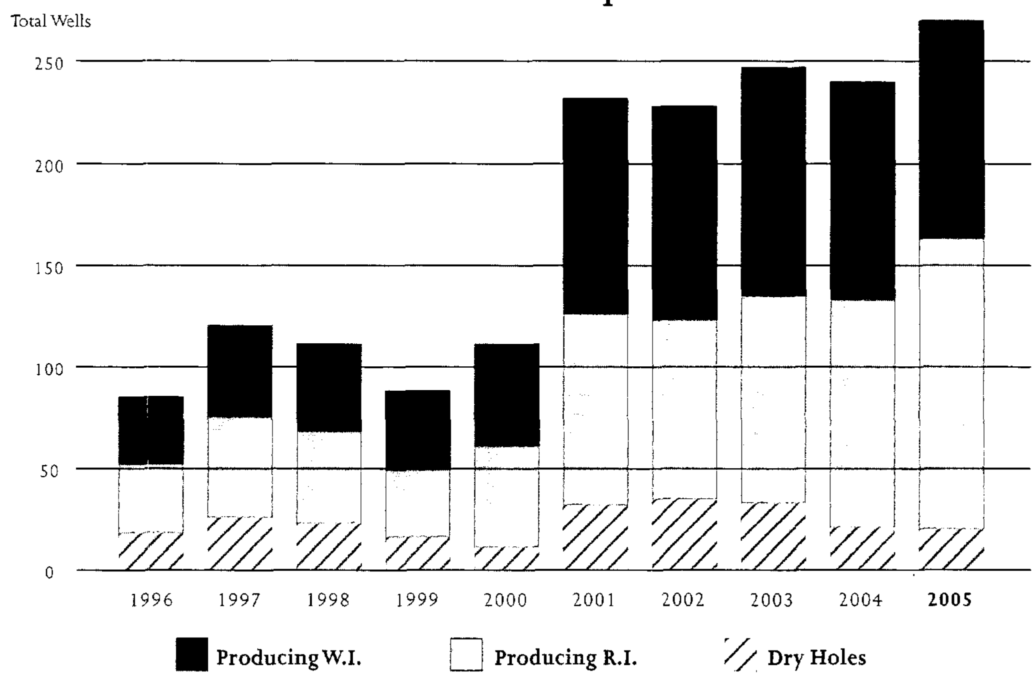
PANHANDLE ROYALTY COMPANY

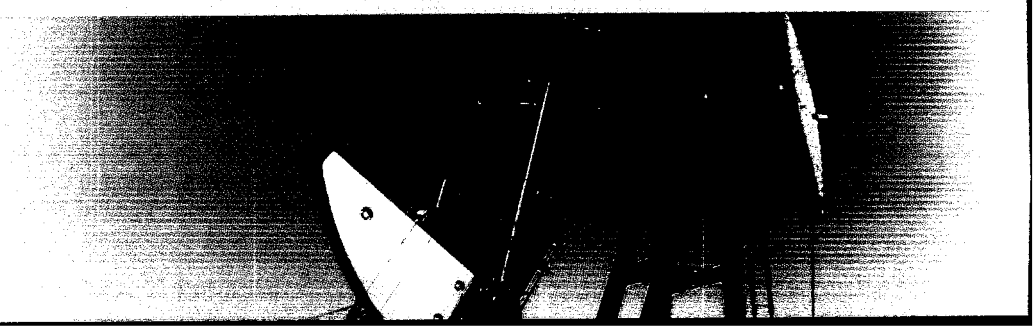
Notes

Notes

PANHANDLE ROYALTY COMPANY

Annual Wells Completed





PANHANDLE ROYALTY COMPANY

[illegible]00 N. Grand Blvd., Suite 305
Oklahoma City, Oklahoma 73112
Phone: 405.948.1560
Fax: 405.948.1063
www.panra.com