PANHANDLE ROYALTY COMPANY

2004
ANNUAL
REPORT

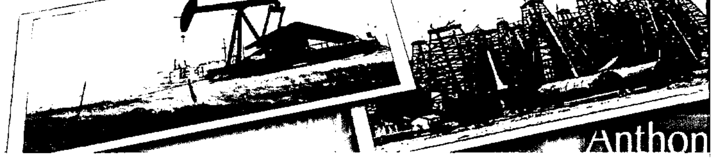
PANHANDLE ROYALTY COMPANY

Fiscal 2004 was an exciting year. It was one where Panhandle established itself firmly at a higher level of activity. It was our second consecutive record financial year. We created a new executive position, Vice President, Chief Operating Officer (COO), and filled it with one of our Board members, Ben Hare. We received record prices for oil and gas sales. We participated in excellent gas discoveries or extensions at Anthon Prospect and Wesley Prospect within Oklahoma. We had a steadily increasing number of new wells in our Carbonate Wash Trend, Mayfield area and "Bread and Butter" Cherokee Trend located in western Oklahoma's Anadarko Basin. Several new development wells were completed in the Tullis area, Cleveland sand reservoir, in Dewey County, western Oklahoma. Proven reserves from new wells completed during the year replaced approximately 150% of fiscal year production with a projected return of investment (ROI) being 3.16/1. We moved our office up one floor in the building to accommodate our expanding activity and personnel, increasing floor space by about 40%. You approved splitting our stock two-for-one in April 2004. Per share cash dividends received increased 28% during the year and 42% on an annualized basis. The trading price of our stock on September 30 was $17.20, a 52% increase in 12 months after adjusting for the stock split. Estimated future cash flow undiscounted of our oil and gas reserves reached a new record of $148,193,000 at a record price of $44.68/bbl and $5.42/mcf. We hope this provides some indication why 2004 was so exciting and busy. Details are provided below and in the following pages.

H.W. Peace II

The record-setting revenue was $24,606,609, which provided net income, after provision for income tax, of $6,729,825 or $1.59 per share. These were increases of 9.6% and 12.9% respectively from fiscal 2003. Pretax income was $9,792,825 or 39.8% of total revenue. From this, the most paid ($752,152) in a year as dividends to shareholders equates to a 11.2% portion of the year's net income. Other new financial records were set in assets at $54,186,362, up 9.7%; shareholder equity at $28,700,515, up 27.4%; and cash flow from operations at $15,515,300, up 17.5%. Costs and expenses rose 3.4% to $14,813,784 with capital expenditures for oil and gas activities being $10,946,471, an increase of 19.2%. At year-end, we had 5,022 producing wells providing this revenue. Approximately 81% of the producers are gas wells and about 1,000 are working interest wells.

We acquired our largest debt in history in October 2001 when we purchased Wood Oil Company. In three years, that has been reduced to $10,516,000. During fiscal 2004, that debt was reduced by $4,150,000 or 28.3%, while $488,000 was paid in interest. We anticipate paying off this existing debt in less than three years. As the debt is paid down, more and more of our cash flow becomes available for well participation and larger drilling budgets. We have set an internal goal to increase our average working interest in new wells from the current 3 to 5% to the 8 to 10% range within the next five years. Such an increase is necessary to grow our reserves, production, and revenue. The results of the Wood acquisition are as we expected and your Company has now reached a higher level of activity and potential growth that was achieved by this increase in size while accompanied by higher oil and gas prices. Besides growth by drilling there is also the possibility of



another acquisition should we find the right fit. A large acquisition would be made with cash from our substantial borrowing base or with Company stock or a combination of the two.

Panhandle has been extremely fortunate for many years in having a strong supportive Board of Directors that sets Company policy in response to what the vast majority of you indicate are your desires for growth and dividends. Two of those Directors have indicated their desire to retire. Jerry Smith, our chairman since February 1997 and a Director since February 1987, is not standing for reelection. His period as a Director and as chairman has seen the Company increase tenfold in revenue and even more in profit, fee mineral ownership has tripled, reserve value is up 700% and Company personnel have tripled. His support and leadership in setting policy is the rock that has underpinned our continuing growth. I hope you will all wish him well in his retirement as he spends much more time with his family and personal business interests. The Company has prospered greatly under his chairmanship.

Michael Cawley has been a Director since December 1991. He also was a strong supporter of policies that created the atmosphere for Panhandle's growth and the foundation for future growth. Shortly after becoming a Director, he was named President of the Noble Foundation, one of the largest nonprofits in the country. His primary responsibilities with Noble and its associated affiliates have grown considerably to where he needed more time for those activities. We will greatly miss his counsel and business knowledge.

Wanda Tucker, Vice President of Land, retired on December 31, 2004, after 26½ years with the Company. She was the Company's longest-serving employee and officer. She became a vice president in 1990. Mrs. Tucker has seen and helped create a tremendous evolution in this Company. It was still a Co-op with only three employees when she was employed. Her knowledge and ability were the grease and the glue that made innumerable acquisitions possible from acquiring New Mexico Osage in the 1980's to the Wood acquisition. Her department grew from just herself to four, plus temporaries and consultants. Her experience and background knowledge of minerals and their deeds and lease agreements was invaluable. We wish her a happy and healthy retirement with her husband and family. The Board has named Ben Spriestersbach as the new Vice President, Land. He has been the land manager for the past three years and is quite familiar with all phases of Company activity.

The Company is losing through retirement three outstanding individuals who have helped establish the policies and execute them over the past two plus decades. We believe those policies and procedures are sound as seen by two continuous years of outstanding growth that followed many years of steady growth. The retirees and all of us here, working for you the shareholder owners of the Company, are optimistic and enthusiastic to continue this growth into the future. We believe the following pages will provide you the information to envision that potential growth from this year's base.

H.W. Peace II
President & Chief Executive Officer

After Deciding He Couldn't Beat Panhandle, Investor Rick Rule Started Buying It

Rick Rule, one of Panhandle Royalty Company's most loyal shareholders for the past 16 years, started out as a competitor. But, upon realizing that he couldn't beat Panhandle at the royalties game, he decided to buy it — or at least some of its stock. Since then, he has convinced many others to do the same.

"I first bought stock in Panhandle back in 1988," Rick says. "We identified it on a value search of true micro-cap oil and gas companies. I'd been involved in oil and gas securities and investing, drilling for my own account and involved in royalty purchases, since the mid 1970s. After Panhandle was identified on a comparative value screen, I called the Company and learned — much to my chagrin — that they were better at the royalty business than I was. So, I decided that it would be easier to be a shareholder than a competitor. I've never changed my mind. Over time, I've just kept buying."

Rick Rule

Rick said he wouldn't describe himself as having been a big competitor to Panhandle prior to becoming a shareholder, but that he had been fairly active for an individual buying perpetual mineral and royalty rights in Texas, Oklahoma and Kansas. "After looking at Panhandle's royalty spread though, I knew I couldn't duplicate it," he adds. "It was just a lot easier to be a third party shareholder."

And that's a role he plans to continue playing — and to interest others in playing as well. "I own a brokerage firm, Global Resource Investments, which is pretty active in the natural resource investment business," he explains. "Once I tried Panhandle as a personal investor, and was pleased with the results, I began investing for client accounts and have continued to do so." In fact, Rick calculates that he's purchased Panhandle stock for approximately 100 clients over the years.

It's safe to say he came by his career naturally. His family was active in oil and gas on a private basis and he has a personal interest in resources and energy. Rick majored in natural resource finance in college. Upon graduation, he became licensed in securities and has pursued natural resource finance and has operated a natural resource brokerage ever since.

Due to his work, Rick and his wife currently divide their time between California, Western Canada and New Zealand. "Because the resource business is global, my life is global. I've been fortunate enough to concentrate my residency on weather. So I'm normally in Western Canada in the summer, in New Zealand during their summer and in California during spring and fall. Changing those times around could prove catastrophic," he says with a laugh.

To his knowledge, Global Resource Investments is the only brokerage firm operating in the U.S. today that focuses its research efforts on smaller public oil and gas, agriculture, mining, and resource businesses. And that research has certainly paid off for Rick and his clients over the years. After all, it was Rick's research in 1988 that first convinced him to begin purchasing Panhandle Royalty Company stock.

"As a shareholder, I've always been pleased by Panhandle's low level of general and administrative expenditures, measured against even production revenue or drilling activity," he says. "It seems to me like shareholders get a lot of bang for the buck with Panhandle. Relative to its peers, the Company's cost structure is excellent. And that's always been attractive to me, both as an investor and as a broker."

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Company operations continued at levels comparable to 2003 during Fiscal Year 2004 with higher product prices encouraging operators to actively seek drilling opportunities. The Company's leasehold and mineral fee holdings provided for the drilling of 172 Working Interest wells and 146 Royalty Interest wells in FY2004. This compares with 169 Working Interest and 150 Royalty Interest wells drilled in FY2003.

The 2004 Working Interest wells resulted in 14 oil wells, 93 gas wells, and 15 dry holes (88% success). The Royalty Interest drilling program discovered 16 oil wells, 96 gas wells, and 6 dry holes (94% success). At year-end, 50 Working Interest wells were drilling or testing, as were 28 Royalty Interest wells. Total identified wells in all categories numbered 527, a year-over-year increase of 24 (5%) compared to 2003.

Most of the drilling occurred in Oklahoma with Roger Mills County having the greatest activity (27 wells) followed by Pittsburgh County with 19 wells. Thirty-six Oklahoma counties were represented in the FY2004 program.

No new acquisitions occurred in FY2004 and only 61.7 new mineral acres were added. Panhandle mineral ownership now totals 259,211 net acres. Leasehold acquisition did continue and 1,013.4 net acres were acquired at a cost of approximately $391,000. The majority of the acres added were in existing plays in which Panhandle is involved or on trend with those plays so Panhandle can benefit from future drilling.

Actual net dollars spent on exploration, development, and land acquisition in FY2004 was $10,856,950 (See Note 9, Notes to Consolidated Financial Statements). In FY2003, Panhandle spent $9,358,699 on exploration, development, and property acquisition.

In FY2004 two new productive prospects emerged as opportunity areas for future drilling and production. They are the Wesley prospect in Atoka County and the Anthon prospect in Custer County. Both had successful wells drilled and completed during the fiscal year and are described begining on the next page. In addition, we had ongoing activity in areas reported on last year and brief updates are provided below.

Working Interest

Category	*2004*	*2003*	*2002*
Pending & Scheduled	103	124	99
Drilling	18	12	11
Testing	32	24	22
Producing	107	113	105
	14 oil, 93 gas	*11 oil, 102 gas*	*20 oil, 85 gas*
Dry Holes	15	20	26
Totals	275	293	263

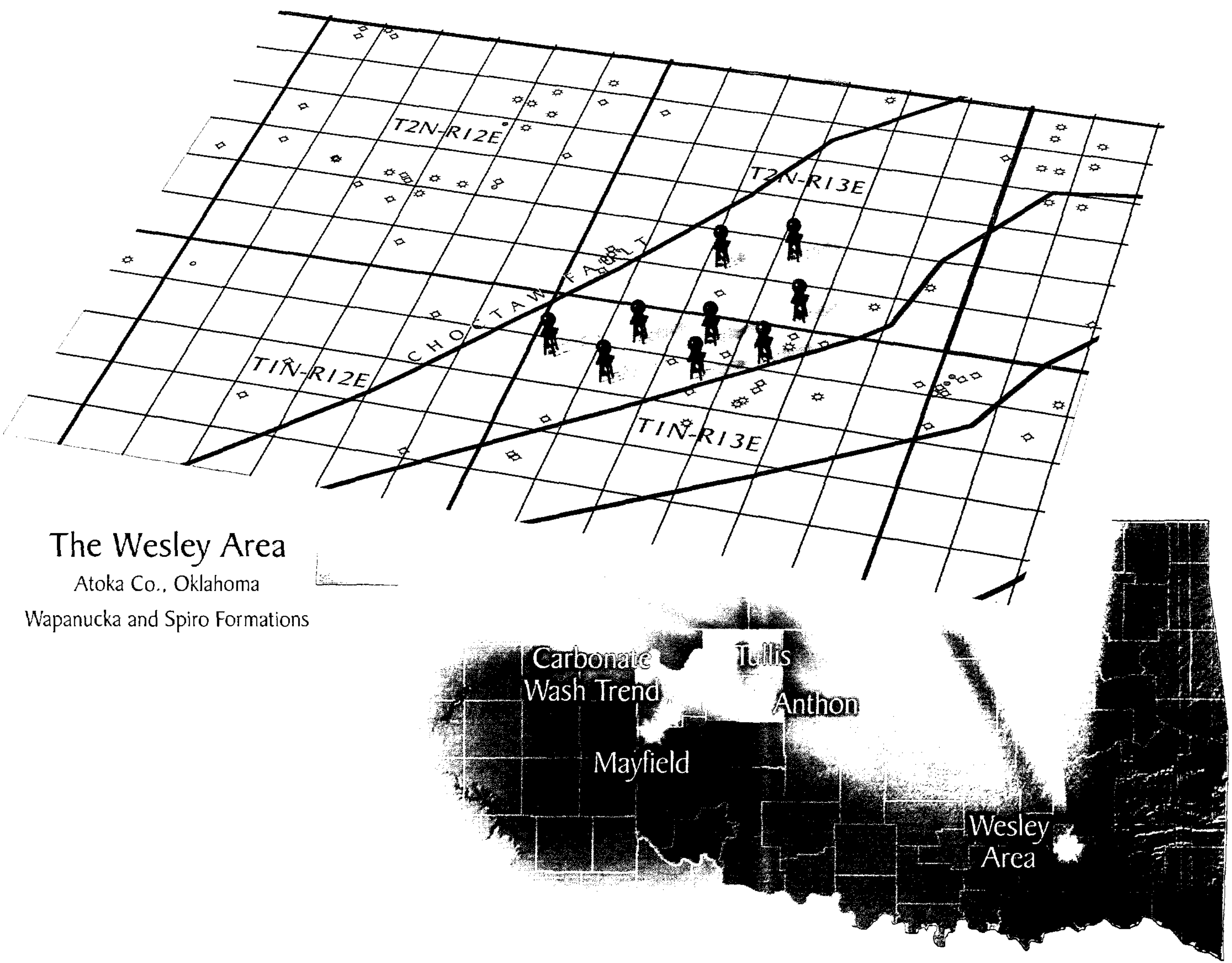
Royalty Interest

Category	*2004*	*2003*	*2002*
Pending & Scheduled	106	60	58
Drilling	5	3	7
Testing	23	21	21
Producing	112	114	88
	16 oil, 96 gas	*14 oil, 100 gas*	*24 oil, 64 gas*
Dry Holes	6	12	9
Totals	252	210	183

For those companies who operate, activity is at a very high level and because of product pricing that level appears to be sustainable. Several of Oklahoma's large independents, for example, appear to be in sharp competition for as many gas reserves as possible. This benefits Panhandle in that we have many more drilling opportunities presented to us. The downside to this environment is that rig availability is impacted and some of our larger, deeper opportunities are being delayed. Competition for leasehold makes it more difficult to acquire lease positions at reasonable cost.

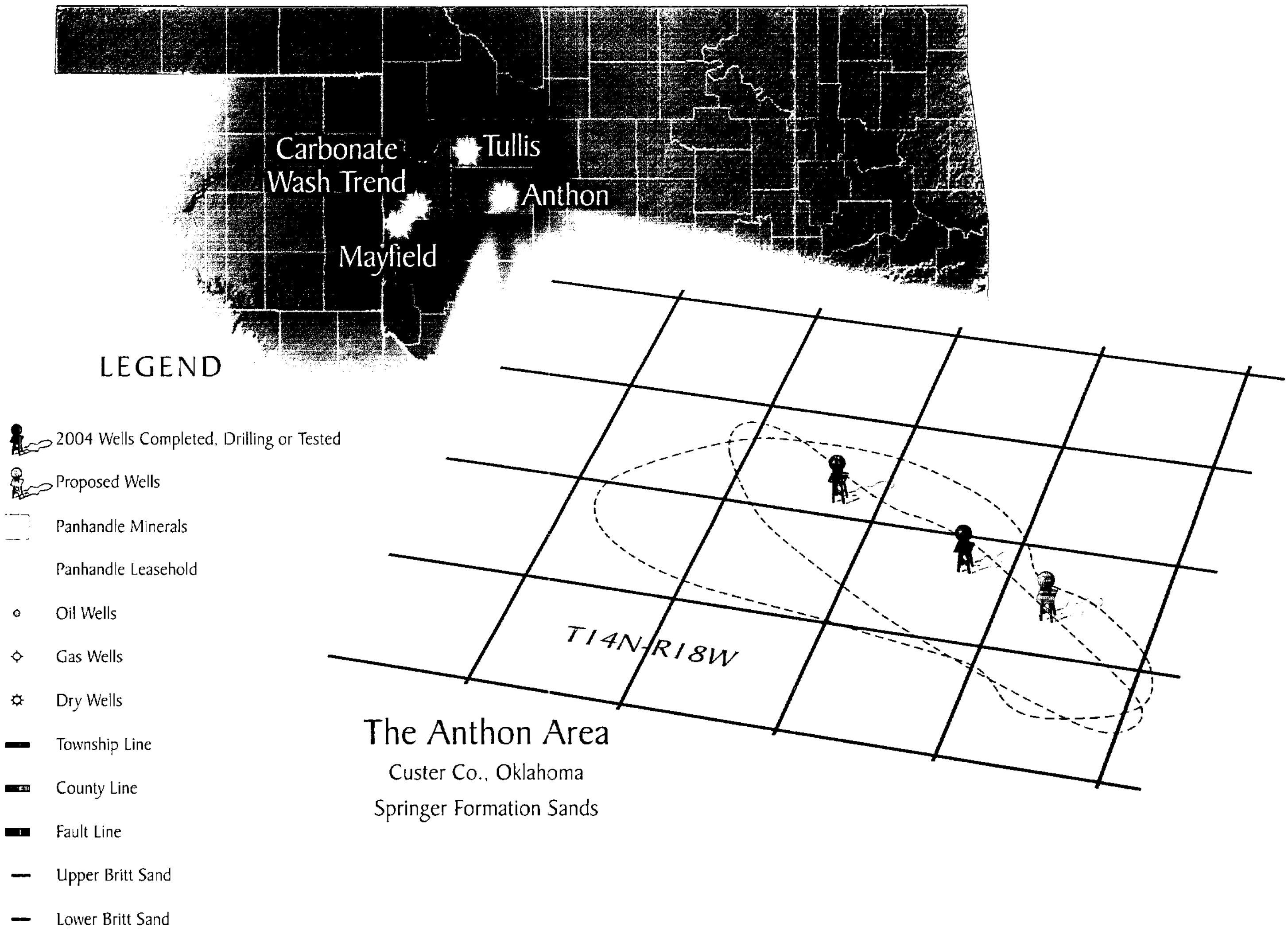
The Wesley Area –

is located in northern Atoka County in southeastern Oklahoma. It is also in the Ouachita Mountain Overthrust geological province, and the prolific Potato Hills Field is in the same province, some 30 miles east. Panhandle Royalty Company participated in one well that was completed in FY2004 and one additional working interest well and two royalty interest wells were drilling or testing over the end of the fiscal year. The Company has agreed to participate with a working interest in five wells expected to be drilled in 2005. Panhandle owns minerals in 34 sections and leases in six sections.



The Wesley Area
Atoka Co., Oklahoma
Wapanucka and Spiro Formations

The Chesapeake Jacqueline 1-7 was completed as a producing gas well from the Wapanucka and Spiro formations after drilling to a total depth of 12,000 feet. The map shows the location of the Jacqueline 1-7, the currently testing Chesapeake McEntire 1-34, the additional known FY2005 wells, and the two currently testing royalty wells. Panhandle has a working interest ranging from 3.1% to 10.9%, as well as royalty and revenue interests of 2.7% to 10.9%. Gross dry hole costs for these wells are approximately $1,000,000 each.



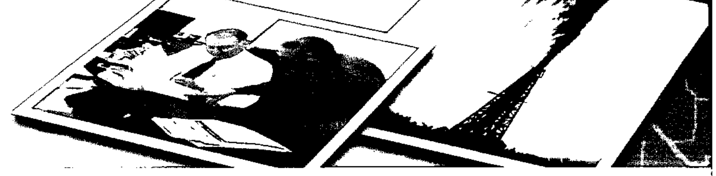
The Anthon Area

Custer Co., Oklahoma

Springer Formation Sands

The Anthon Area –

is located in northern Custer County, western Oklahoma, in the Anadarko Basin geological province. Panhandle participated with a working interest in a successful gas discovery, the Duncan Hatcher 1-1. The well was completed in Springer Formation Sands at 13,400 feet and tested gas at rates up to 6.0 MMCFGD. The Company has minerals and leasehold in 6 sections of this prospect with an average working interest of 5.5%. Two additional wells have been proposed for FY2005 and others are expected. Gross dry hole costs for these wells are $1.2 to $1.6 MM each. The map shows our acreage position and the locations of the Hatcher well and 2005 proposed wells.



The "Carbonate Wash" Trend –

continues to be one of our most active areas. This play is located in southern Roger Mills County, also in the Anadarko Basin. In FY2004, the Company participated in six completed wells, all of which were successful. Three additional wells were drilling or testing at the end of the fiscal year. Working interests range from 2.4% to 9.5%. In the fiscal year Panhandle spent approximately $725,000 drilling and completing wells in this play.

Panhandle has minerals in 27 sections and has been active buying leasehold in this area. The Company has leasehold in 15 sections.

The Mayfield Area –

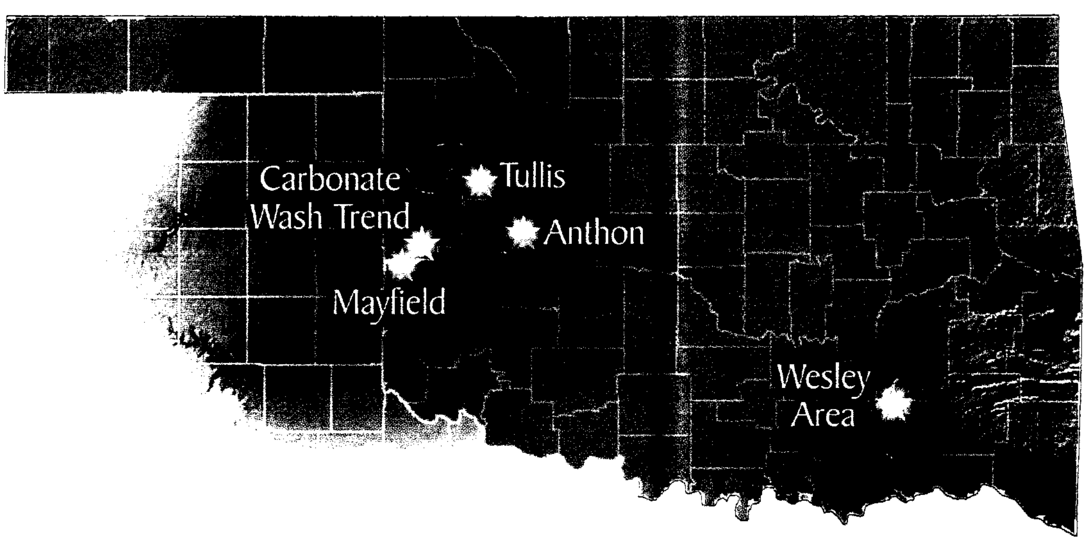
is located in northern Beckham and southern Roger Mills County, in the Anadarko Basin-Mountain Front geological province. The Company participated in 10 wells last fiscal year, five of which were completed and five which were drilling or testing at year's end. The three most significant completions were the St. Mary Land and Exploration, Juanita 1-30, Dobson Ranch 1-31, and Sanguine Gas Exploration, Carolyn 1-23 wells where the Company had working interests of 5.4%, 6.2%, and 7.4% respectively. Panhandle has mineral acreage in 10 sections and leasehold in one of those sections. In addition, Panhandle has minerals in nine sections on the east side of Mayfield. To date, there is one producing well in that acreage.

During FY2004, the Company invested $1,128,000 for drilling and completions in the Mayfield area.

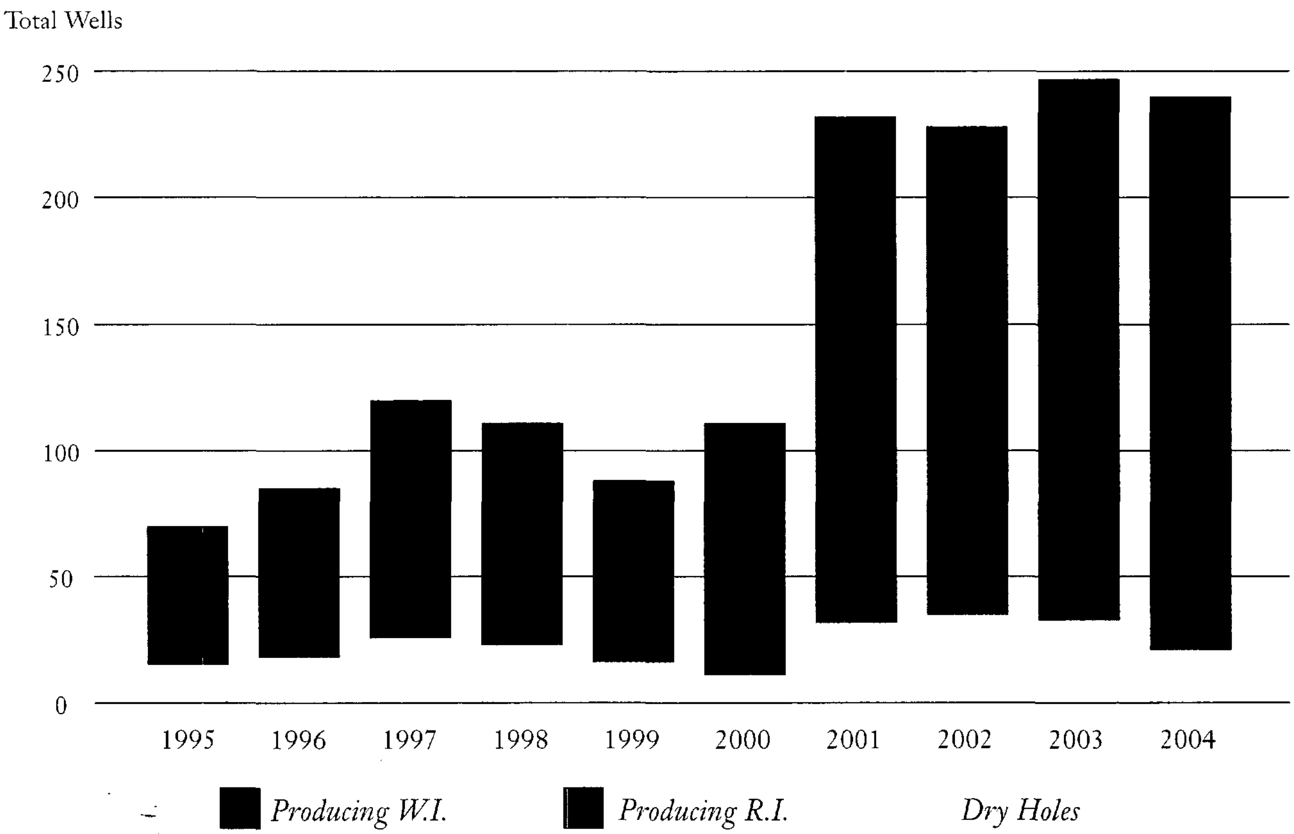
The Tullis Area –

is a maturing play in Dewey County that has good historical results for the Company. In 2004, Panhandle participated in 10 wells with a drilling and completion expenditure of $1,022,000. It is expected to be an active area through 2005.

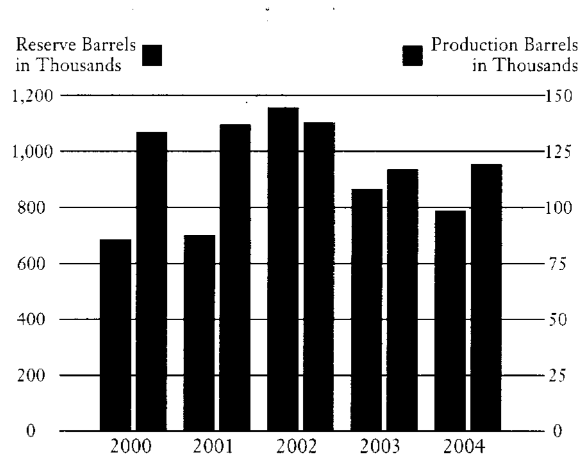
Panhandle Royalty has leases in 20 sections. Working interests range from 11.5% to 16.6%. Dating back to 2001, Panhandle and Wood have working interests in 49 wells.



Annual Wells Completed



Reserves

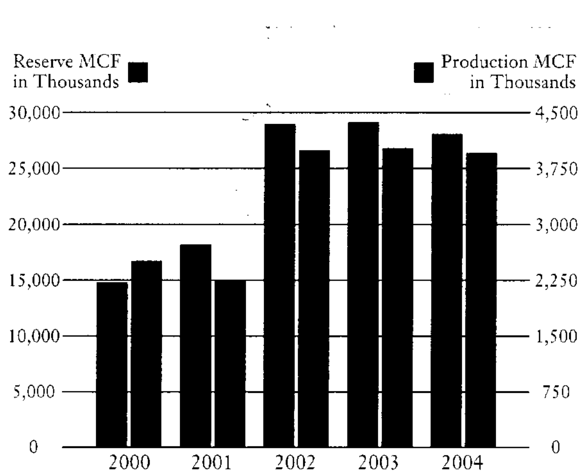


Barrels of Oil Reserves/Production

Proven reserve additions from new wells completed or recompleted during the year were 89,092 barrels and 6,331,100 MCF or 6,865,652 MCF equivalent where the energy equivalent of a barrel is equal to 6,000 cubic feet of gas. On a MCFE basis, this was a replacement of 150% of net production. However, there were downward revisions of older proven reserves amounting to 49,749 barrels and 2,483,100 MCF or 2,781,584 MCFE. After subtracting production and revisions from new well additions, overall reserves declined 1.4% to 32,812,000 MCFE. Most of the downward revision in older proven reserves is attributed to our oil reserves and gas associated with the oil. This came primarily from our single largest interest oil field, *Dagger Draw*, in *southeast New Mexico*. This *Dagger Draw* proven reserve loss was due to our largest operator not having commenced a secondary recovery project approved in fiscal 2003 by the working interest participants. The operator indicates it is still awaiting state regulatory agency approval. Most of these revisions were in the proved undeveloped category where it appears the timing of drilling the infill wells is indeterminate.

The largest portion of the downward revision in previous proven gas reserves came from not replacing proven undeveloped reserves that were drilled and moved to proven producing or were dropped from the proven undeveloped list due to uncertainty as to when they would be drilled by the operator. As a non-operator, it is difficult to say for sure a proven undeveloped well will be drilled by the operator in a reasonable time frame unless we have a well proposal or letter from them stating when they intend to drill. For this reason, we may continually have fewer proven undeveloped reserves in the future than operating companies, which have control of when they intend to drill a certain well.

Higher oil and gas prices on September 30, 2004, allowed the Company to see its greatest reserve value in history. After deduction of future operating cost and production tax, the undiscounted future cumulative cash flow from these proven reserves before future income tax was $148,193,000. At a 10% discount, this equates to $97,213,000; these were increases of 28% and 28.8% respectively from fiscal 2003. The September 30, 2003, price was $5.42/MCF and $44.68 barrel. These amounts do not include carbon dioxide reserves of 1,231,453 MCF with future cumulative cash flow at $413,854 undiscounted and $253,842 discounted at 10%. The carbon dioxide is all located in the *McElmo Dome CO_2 Field* of *southwest Colorado* where it is produced and sold to companies in the Permian Basin for tertiary enhanced oil production.



MCF of Gas Reserves/Production

The proven reserves of all types added during the year from new wells completed during the year, divided by those well costs provided an ultimate future return of investment (ROI) of 3.16/1. Stated differently, if the price we receive in the future is exactly the price we had on September 30, 2004, then we will receive $3.16 for each dollar spent in drilling and completing the well after all operating expenses and production taxes have been paid.

Reserves

Proved Developed Reserves	*Barrels of Oil*	*MCF of Gas*
September 30, 2000	408,732	11,585,331
September 30, 2001	412,705	13,236,455
September 30, 2002	820,790	22,896,330
September 30, 2003	703,400	23,599,473 (1)
September 30, 2004	710,513	24,086,120 (1)

Proved Undeveloped Reserves	*Barrels of Oil*	*MCF of Gas*
September 30, 2000	251,508	2,803,789
September 30, 2001	263,386	4,451,895
September 30, 2002	294,415	5,219,570
September 30, 2003	132,575	4,670,400
September 30, 2004	49,729	4,164,633

Total Proved Reserves	*Barrels of Oil*	*MCF of Gas*
September 30, 2000	660,240	14,389,120
September 30, 2001	676,091	17,688,350
September 30, 2002	1,115,205	28,115,900
September 30, 2003	835,978	28,269,873 (1)
September 30, 2004	760,242	28,250,753 (1)

(1) *These reserve amounts are net of approximately 1.2 bcf of CO_2 gas reserves and the estimated future net cash flows from those reserves.*

Estimated future net cash flows:

	9-30-04	*9-30-03*	*9-30-02*	*9-30-01*	*9-30-00*
Proved Developed	$129,410,259	$97,847,582	$76,081,978	$25,797,780	$48,481,740
Proved Undeveloped	$18,782,490	$17,893,760	$18,572,672	$10,141,828	$16,604,661
Total Proved (1)	$148,192,749	$115,741,342	$94,654,650	$35,939,608	$65,086,401

10% Discounted present value of estimated future net cash flows:

	9-30-04	*9-30-03*	*9-30-02*	*9-30-01*	*9-30-00*
Proved Developed	$84,400,194	$63,591,623	$49,485,409	$17,533,672	$32,122,191
Proved Undeveloped	$12,812,424	$11,905,681	$11,868,812	$6,589,021	$11,417,769
Total Proved (1)	$97,212,618	$75,497,304	$61,354,221	$24,122,693	$43,539,960

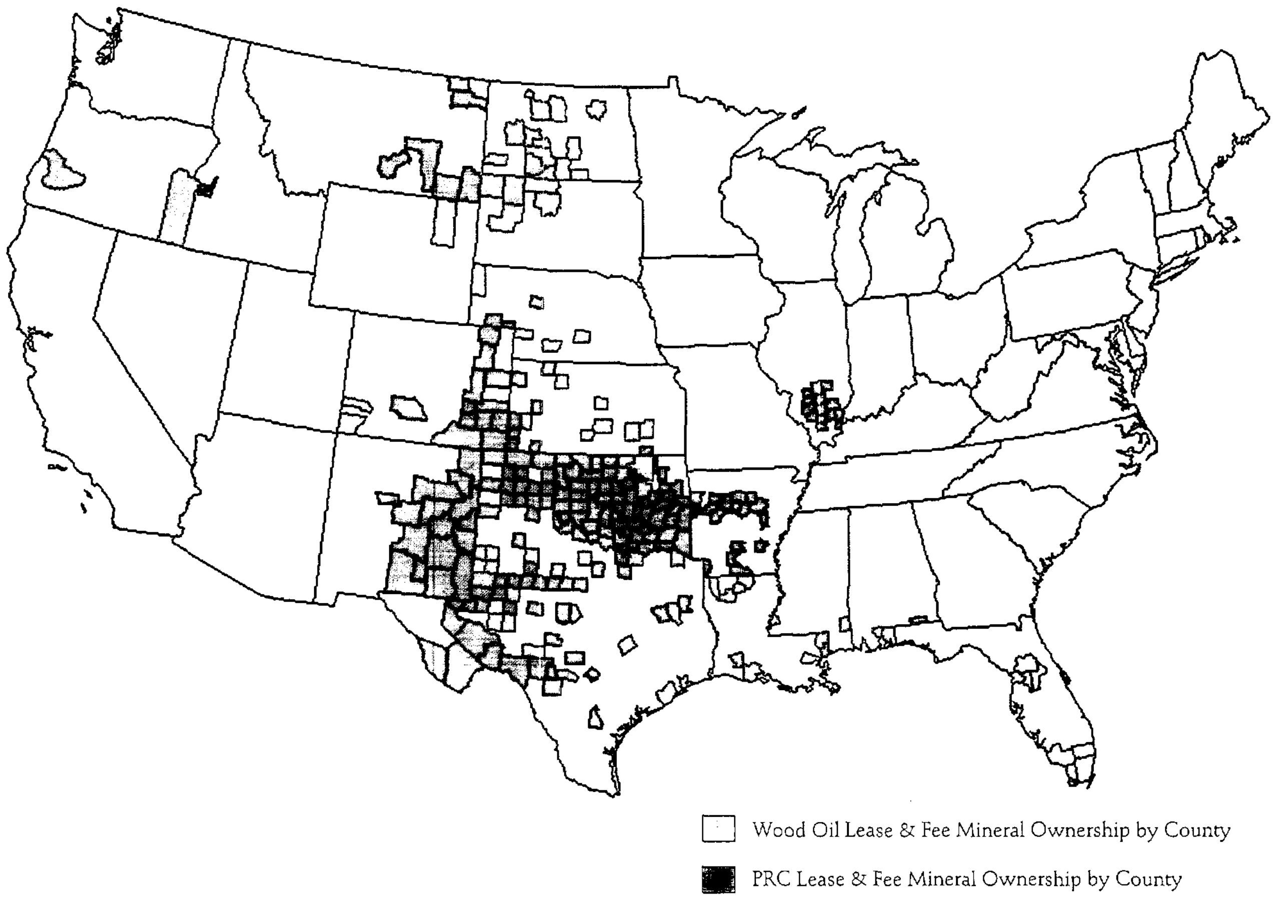
(1) *Before income taxes. Prices used for determining future cash flows from oil and natural gas were as follows: 2004 - $44.68, $5.42; 2003 - $27.39, $4.43; 2002 - $27.76, $3.12; 2001- $24.03, $1.81; 2000 - $32.84, $3.96*

Mineral Interests

	Net Acres	Gross Acres	Net Acres Prod'g	Gross Acres Prod'g	Net Acres Leased	Gross Acres Leased	Net Acres Open	Gross Acres Open
Arkansas	10,050	44,596	1,073	2,836			8,977	41,760
Colorado	8,326	39,299	109	219	31	200	8,186	38,880
Florida	6,839	13,849					6,839	13,849
Illinois	1,068	4,979	40	261			1,028	4,718
Kansas	3,122	11,976	112	1,120	40	160	2,970	10,696
Montana	1,007	17,947					1,007	17,947
Nebraska	1,319	13,249					1,319	13,249
New Mexico	57,396	174,460	1,335	6,200	47	125	56,014	168,135
North Dakota	11,179	64,286					11,179	64,286
Oklahoma	113,089	940,620	29,616	242,845	2,509	20,388	80,964	677,387
South Dakota	1,825	9,300					1,825	9,300
Texas	43,085	361,182	7,173	88,872	877	4,987	35,035	267,323
Other	906	6,112					906	6,112
Total:	259,211	1,701,855	39,458	342,353	3,504	25,860	216,249	1,333,642

Leases

State	Net Acres	Net Lease Acres Expiring 2005	2006	2007	Net Acres Held by Production
Kansas	2,117	–	–	–	2,117
New Mexico	528	–	–	–	528
Oklahoma	14,442	469	645	908	12,420
Texas	396	–	–	64	332
Other	1,298	–	–	–	1,298
Total	18,781	469	645	972	16,695



During fiscal 2004 Panhandle continued to sell small amounts of minerals outside of its core area of Mid Continent and southwestern states. Most of the mineral sales were as individual lots where developers are building housing subdivisions in central Florida. The number of net fee mineral acres owned at fiscal year end was 259,211 or 179 less than fiscal 2003. There were 39,458 acres producing oil and gas and another 3,504 under lease to operators from this total. The number of producing acres increased 5.2% or 1,963 acres from fiscal 2003. The number of acres leased to others but not yet producing increased 89.4% or 1,654 acres. The adjacent table indicates this ownership by state.

The Company holds leases where it owns no minerals on 18,781 net acres with 16,695 net acres or 87.5% being held by production. During the year a net 1,013 new leasehold acres were acquired for $391,000 while a total of 2,459 acres of leases expired during the year. Overall total leasehold declined 7.1% compared to fiscal 2003. Producing leasehold, however, increased 2.1% or 342 net acres compared to fiscal 2003. Ninety-three percent of the new leases acquired were in the Carbonate Wash Trend, Cherokee Trend, Mayfield Area or Anthon Area in western Oklahoma's Anadarko Basin following a decision to attempt to increase our average new well working interest to the 8 - 10% range over the next five years. To increase our working interest we must acquire leasehold since Company mineral ownership of 30 to 40 acres in a section or unit normally provides only 4.8 - 6.2% Working Interest.

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,				
	2004(A)	*2003(A)*	*2002(A)*	*2001*	*2000*
Revenues					
Oil & Gas Sales	$ 23,578,615	$ 22,098,198	$ 13,080,754	$ 12,546,055	$ 9,091,920
Lease Bonuses	115,938	72,765	41,497	17,991	82,030
Interest & Other	912,056	285,075	469,146	231,876	104,024
	$24,606,609	$ 22,456,038	$ 13,591,397	$ 12,795,922	$ 9,277,974
Costs & Expenses					
Lease Oper. Exp. & Prod. Taxes	$ 4,098,124	$ 4,013,572	$ 3,001,449	$ 1,771,789	$ 1,458,935
Exploration Costs (B)	236,939	469,224	417,971	947,046	514,739
Depr. Depl. Amortization	6,115,500	5,783,457	5,845,779	1,670,961	1,789,491
Provision for Impairment	841,687	692,220	1,116,234	848,535	262,998
Gen. & Administrative	3,033,437	2,666,177	2,263,908	1,689,426	1,450,241
Interest Expense	488,097	699,266	895,997	779	15,643
	$ 14,813,784	$ 14,323,916	$ 13,541,338	$ 6,928,536	$ 5,492,047
Income before Provision (Benefit) for Income Taxes	$ 9,792,825	$ 8,132,122	$ 50,059	$ 5,867,386	$ 3,785,927
Cumulative effect of accounting changes, net of taxes of $28,500 (C)	–	46,500	–	–	–
Provision (Benefit) for Income Taxes	3,063,000	2,217,000	(293,000)	1,600,000	925,000
Net Income	$ 6,729,825	$ 5,961,622	$ 343,059	$ 4,267,386	$ 2,860,927

	Year Ended September 30,				
	2004(A)	*2003(A)*	*2002(A)*	*2001*	*2000*
Diluted Earnings per share	$ 1.59	$ 1.42	$ .08	$ 1.02	$ .69
Dividends Declared per share	$ .18	$ .14	$ .14	$ .18	$ .14
Weighted Average					
Shares Outstanding					
Basic	4,178,783	4,162,744	4,135,744	4,120,218	4,110,940
Diluted	4,228,801	4,207,426	4,179,944	4,170,088	4,154,860
Net Cash Provided					
By Operating Activities	$ 15,515,300	$ 13,198,368	$ 7,481,195	$ 9,302,965	$ 5,366,066
Total Assets	$ 54,186,362	$ 49,402,534	$ 44,837,060	$ 25,279,684	$ 16,210,327
Long-Term Debt	$ 8,516,657	$ 12,666,661	$ 14,024,000	$ 4,050,000	$ 0
Shareholder's Equity	$ 28,700,515	$ 22,527,685	$ 16,953,294	$ 16,995,050	$ 13,353,814

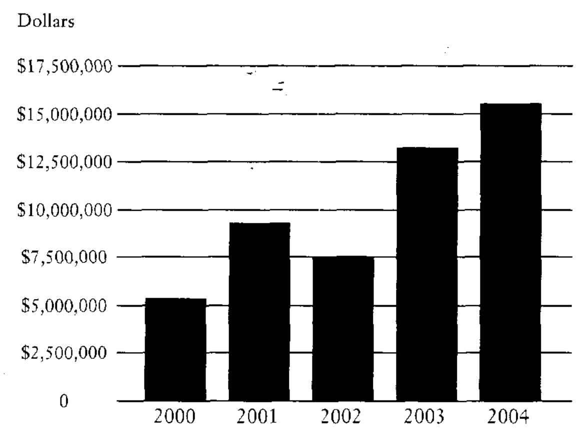
All per share amounts are adjusted for the effect of the 2-for-1 stock split which was effective April 16, 2004.

(A) 2002, 2003 and 2004 results included are consolidated amounts of Panhandle Royalty Company and 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, 2002. See Note 1: Summary of Significant Accounting Policies of Notes to the Condensed Consolidated Financial Statements for a complete discussion.

Forward-looking statements for 2005 and later periods are made throughout this report. Such statements represent estimates of management based on the Company's historical operating trends, its proved oil and gas reserves and other information currently available to management. The Company cautions that the forward-looking statements provided herein are subject to all the risks and uncertainties incident to the acquisition, development and marketing of, and exploration for oil and gas reserves. These risks include, but are not limited to oil and natural gas price risk, environmental risk, drilling risk, reserve quantity risk, and operations and production risks. For all the above reasons, actual results may vary materially from the forward-looking statements, and there is no assurance that the assumptions used are necessarily the most likely to occur.



Cash Flow from 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 following table reflects certain operating data for the periods presented:

	For the Year Ended September 30,		
	2004	*2003*	*2002*
Production:			
Oil (bbls)	114,986	112,746	132,514
Gas (mcf)	3,863,277	3,926,124	3,897,084
Average Sales Price:			
Oil (per bbl)	$ 35.89	$ 29.30	$ 22.48
Gas (per mcf)	$ 5.03	$ 4.79	$ 2.59

Results of Operations 2004 Compared to 2003

Overview

The Company recorded a net income of $6,729,825 in 2004, compared to a 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)

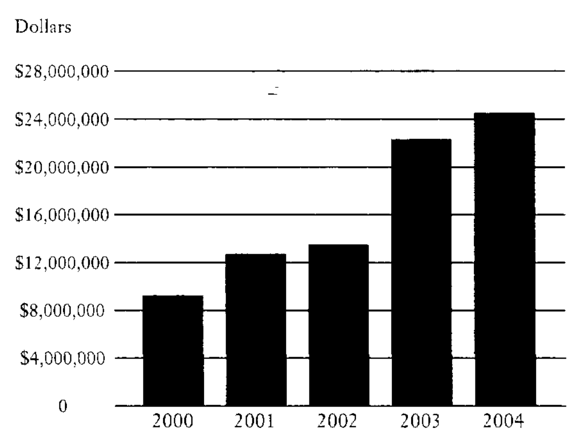
LOE continues to increase each year as the Company increases the number of working interest wells in which it has an interest and due to normal inflation of costs. Gross production taxes are paid as a percentage of oil and gas sales revenues and thus, increased in 2004 due to the increase in oil and gas sales revenues.

Exploration Costs

Exploration costs decreased $232,285 or 50% in 2004 as compared to 2003. The Company utilizes the successful efforts method of accounting for oil and gas operations; thus, only exploratory dry holes result in their costs being charged to exploration costs. In fiscal 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 is 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.



Revenues

Provision For Impairment

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

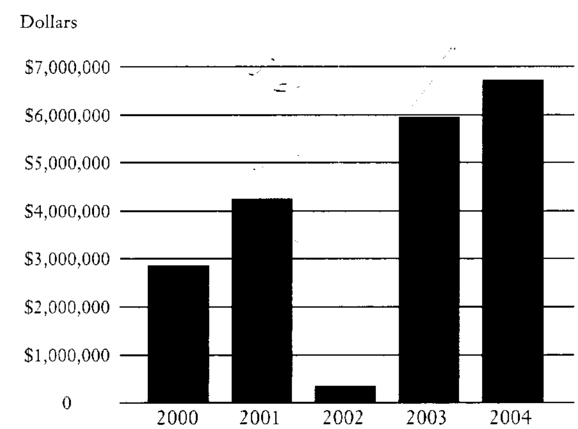
approximately $130,000 in 2004. The increase resulted from the Company recognizing a charge to G&A to adjust the potential shares in the Plan to market price at September 30, 2004. The non-employee directors have taken these potential shares, rather than a cash payment for their directors' fees.

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 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 31% in 2004, 27% in 2003, while a tax benefit was provided in 2002.



Net Income

Liquidity and Capital Resources

At September 30, 2004, the Company had positive working capital of $1,941,634 as compared to $1,335,344 at September 30, 2003. The increase in working capital at September 30, 2004, compared to September 30, 2003, is the result of increased oil and gas sales revenues during 2004 which is discussed in Results of Operation above. Cash flow from operating activities increased 18% to $15,515,300 for fiscal 2004, as compared to fiscal 2003, primarily due to the increase in oil and gas sales prices.

Capital expenditures for oil and gas activities for 2004 amounted to $10,946,471, as compared to $9,195,916 for 2003. 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 2004, the Company borrowed on its revolving bank loan to help fund those expenditures. However, as a result of the increased cash flow from higher prices received for natural gas in fiscal 2004, the Company was able to reduce its bank debt by a net of $4,150,004. Approximately $12 million is available under the Company's current bank debt facility for capital expenditures, acquisitions or any combination of uses. Further, the credit facility could be increased, if needed, for a large acquisition. The Company expects to increase its capital expenditure level to approximately $12 million in 2005. Funds for this level of expenditures will come from cash flow and/or bank debt, if required.

Contractual Obligations

The Company has a credit facility with BancFirst of Oklahoma City, Oklahoma. The facility 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 facility is $22,500,000. The term loan matures on April 1, 2008, and the revolving loan matures on March 31, 2006. 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 3/4% (4.0% at September 30, 2004) or LIBOR (for one, three or six month periods), plus 1.80%. The Company, at September 30, 2004, has elected the prime rate option.

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, 2004. 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, 2004, the Company was in compliance with the covenants.

The table below summarizes the Company's contractual obligations as of September 30, 2004:

Contractual Obligations	*Total*	*Less than 1 Year*	*1-3 Years*	*3-5 Years*	*More than 5 Years*
Long-term debt obligations	$ 10,516,661	$ 2,000,004	$ 7,350,008	$1,166,649	—

Results of Operations 2003 Compared to 2002

Overview

The Company recorded a net income of $5,961,622 in 2003, compared to a net income of $343,059 in 2002. Total revenues were larger as a result of significantly increased oil and gas sales revenues generated by increases in the average sales prices of oil and natural gas in 2003 as compared to 2002.

Revenues

Total revenues increased 65% to $22,456,038 in 2003 compared to $13,591,397 in 2002. The increase was due to a large increase in the average sales price for natural gas in 2003, offset somewhat by a 15% decrease in oil production volumes in 2003. Gas production volume was basically flat in 2003 compared to 2002. New production from the Company's drilling activity replaced the normal production decline of existing gas wells allowing gas production to remain flat. Fewer oil wells have been drilled in recent years, thus, oil production continues to decline as existing well production continues its normal decline.

Lease Operating Expenses and Production Taxes (LOE)

LOE continues to increase each year as the Company increases the number of working interest wells in which it has an interest and due to normal inflation of costs. The Company participated in a record number of working interest wells in 2003. Gross production taxes are paid as a percentage of oil and gas sales revenues and thus increased substantially in 2003 due to the large increase in oil and gas sales revenues.

Exploration Costs

Exploration costs increased $51,253 or 12% in 2003 as compared to 2002. The increased costs were primarily dry hole costs. As previously mentioned, the Company participated in a record number of wells in 2003, several of which were exploratory wells. As the Company utilizes the successful efforts method of accounting for oil and gas operations, exploratory dry holes result in the expensing of all costs associated with those wells. Several of the exploratory wells drilled in 2003 were dry holes.

Depreciation, Depletion And Amortization (DD&A)

DD&A declined $62,322 or 1% in 2003. The decline was principally due to decreased oil production volume in 2003; reducing the units of production, DD&A on the Company's oil properties.

Provision For Impairment

The provision for impairment of the Company's oil and gas properties decreased $424,014, or 38% in 2003. This decrease can be principally attributed to the higher market price for natural gas at year-end 2003 as compared to year-end 2002, which increased the fair value of the Company's oil and gas properties in 2003 as compared to the carrying amount of the properties.

General and Administrative Costs (G&A)

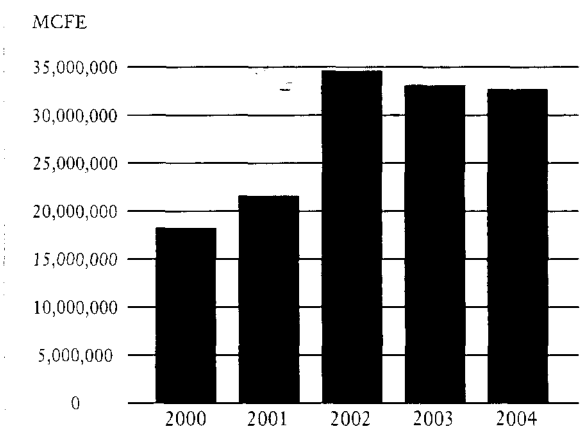
G&A costs increased $402,269 in 2003. Personnel related expenses (including salaries, payroll taxes, insurance expenses and ESOP expenses) increased approximately $137,000 in 2003. G&A expense related to the Non-Employee Directors Deferred Compensation Plan ("the Plan") increased approximately $180,000 in 2003. This increase was a result of the Company recognizing a charge to general and administrative expense to adjust the potential shares in the Plan to market price at September 30, 2003, versus a minimal charge in 2002 for the same adjustment. The non-employee directors have taken these potential shares, rather than a cash payment for their director's fees. In addition, the Company incurred expenses of approximately $50,000 upon listing its shares on the American Stock Exchange in 2003.

Interest Expense

Interest expense decreased $196,731 or 22% in 2003. The decrease was due to lower outstanding debt balances and lower effective interest rates.

Provision For Income Taxes

The provision for income taxes increased in 2003, due to a much larger income before taxes (as discussed above). The Company continued to be able to utilize tax credits from production of "tight gas sands" natural gas and 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 27% in 2003 and 2001, while a tax benefit was provided in 2002.



Proven Reserves – MCFE

Liquidity and Capital Resources

At September 30, 2003, the Company had positive working capital of $1,335,344 as compared to negative working capital of $2,399,457 at September 30, 2002. The increase in working capital from September 30, 2002, to September 30, 2003, is the result of increased oil and gas sales revenues during 2003, which is discussed in "Results of Operation," and the reduction in the current portion of long-term debt by $2,000,000. This reduction in the current portion of long-term debt is the result of the restructuring of the Company's bank debt in March 2003. The fixed monthly principal payment on the bank debt was reduced from $333,000 to $166,667. For a further discussion of the Company's bank debt see "Note 4: Long-Term Debt" of Notes to the Condensed Consolidated Financial Statements. Cash flow from operating activities increased 76% to $13,198,368 for fiscal 2003, as compared to fiscal 2002, primarily due to a significant increase in product sales prices.

Capital expenditures for oil and gas activities for 2003 amounted to $9,195,916, as compared to $6,967,767 for 2002, exclusive of $15,229,466 used to acquire Wood Oil Company. 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 2003, the Company borrowed, early in the year, $1,525,000 on its revolving bank loan to help fund those expenditures. As a result of the increased cash flow from higher prices received for natural gas in the last three quarters of fiscal 2003, the Company made total principal payments of $4,878,335 on its bank debt. The Company has approximately $7.8 million available credit under the bank debt facility which is in place, for capital expenditures, acquisitions or any combination of uses. Further, the credit facility could be increased, if needed, for a large acquisition.

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 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.

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. Changes in crude oil and natural gas reserve estimates affect the Company's calculation of depreciation and depletion, provision for abandonment and assessment of the need for asset impairments. 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. As previously discussed, 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 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 field 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 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 a significant amount of judgment since the results are based on estimated future events, such as inflation rates, future sales prices for oil and gas, future costs to produce these products, 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 field for impairment may result from significant declines in sales prices or unfavorable adjustments to oil and gas reserves. Any assets held for sale are reviewed for impairment when the Company approves the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded.

Tax Accruals

The estimation of the amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations. 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.

Quantitative and Qualitative Disclosure About Market Risk

The Company's results of operations and operating cash flows are impacted by changes in market prices for oil and gas. Operations and cash flows are also impacted 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 3/4% or LIBOR for one, three or six month periods, plus 1.8%. At September 30, 2004, a 1% change in the prime interest rate would result in approximately a $33,500 change in annual interest expense. The Company has a $10,000,000 term loan (outstanding balance of $7,166,661 at September 30, 2004) which matures on April 1, 2008. The interest rate is fixed at 4.56% until maturity.

The Company's common stock is listed on the American Stock Exchange (symbol PHX). The following table sets forth the high and low trade prices of the Company's common stock during the periods indicated (all share or per share amounts are adjusted for a 2-for-1 stock split which was effective April 16, 2004):

Quarter Ended	*High*	*Low*
December 31, 2002	$ 10.10	$ 6.00
March 31, 2003	$ 9.07	$ 7.63
June 30, 2003	$ 11.92	$ 7.47
September 30, 2003	$11.96	$ 10.70
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

As of December 3, 2004, there were approximately 3,190 holders of record of the Company's class A common stock.

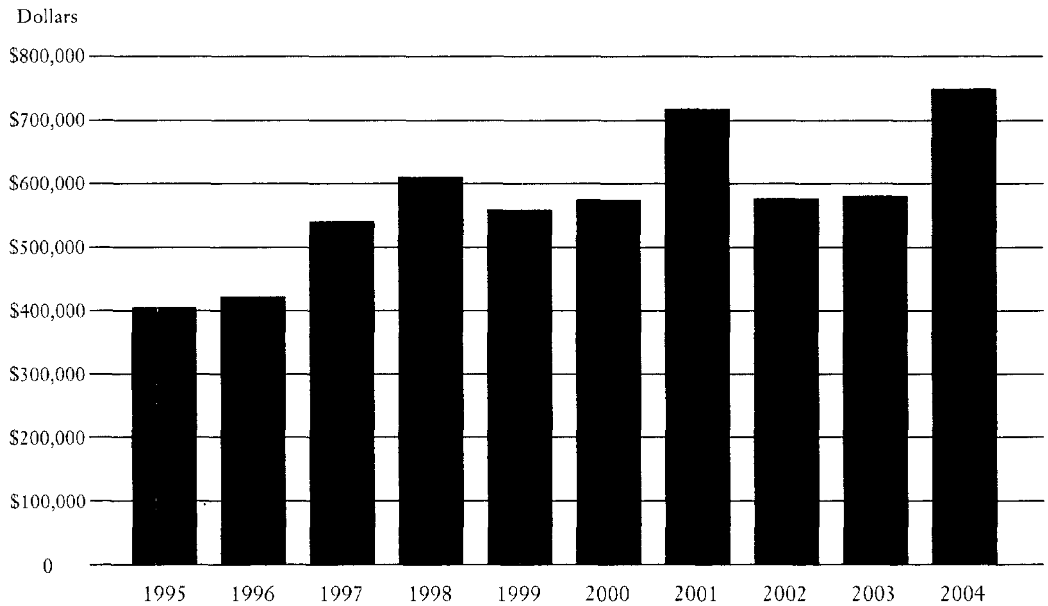
During the past two years, cash dividends have been paid as follows on the class A common stock:

Date	*Rate Per Share*
December 2002	$ .035
March 2003	$ .035
June 2003	$ .035
September 2003	$ .035
December 2003	$ .04
March 2004	$ .04
June 2004	$ .05
September 2004	$ .05

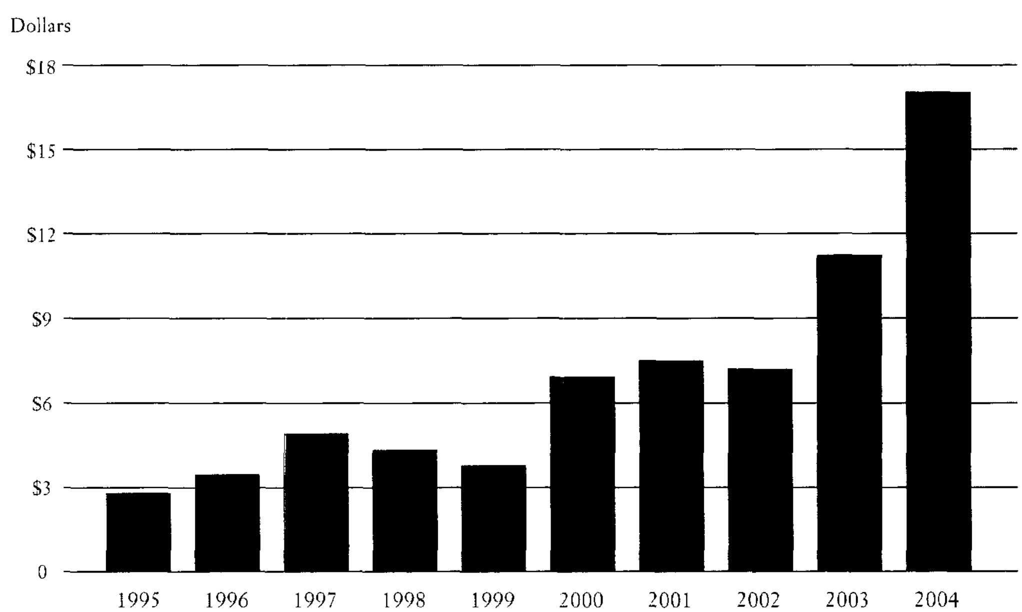
The Company's line-of-credit loan agreement contains a provision limiting the paying or declaring of a cash dividend to 50 percent of cash flow, as defined, of the preceding 12-month period. See Note 4 to the consolidated financial statements contained herein.

The Company's annual meeting is scheduled for February 25, 2005, at the Crowne Plaza Oklahoma City, 2945 NW Expressway, Oklahoma City, Oklahoma, at 9:00 a.m. Notice of the meeting and a proxy statement will be sent to shareholders in late January 2005.

Dividends Paid



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.

PANHANDLE ROYALTY COMPANY

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Panhandle Royalty Company

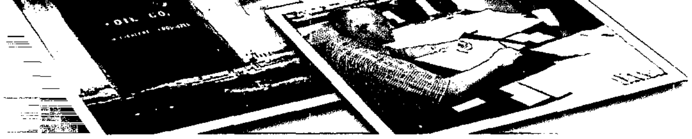
We have audited the accompanying consolidated balance sheets of Panhandle Royalty Company (the Company) as of September 30, 2004 and 2003, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2004. These 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. 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, 2004 and 2003, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2004, in conformity with U.S. generally accepted accounting principles.

Ernst & Young LLP
Oklahoma City, Oklahoma

December 6, 2004



Consolidated Balance Sheets

	September 30, 2004	September 30, 2003
Assets		
Current assets:		
Cash and cash equivalents	$ 642,343	$ 593,006
Oil and gas sales receivable	4,962,992	3,989,877
Income tax and other receivables	239,895	117,422
Total current assets	5,845,230	4,700,305
Property and equipment at cost, based on successful efforts accounting:		
Producing oil and gas properties	74,928,073	65,342,062
Non-producing oil and gas properties	9,790,377	9,610,757
Furniture and fixtures	471,564	405,514
	85,190,014	75,358,333
Less accumulated depreciation, depletion, and amortization	37,755,438	31,685,848
Net properties and equipment	47,434,576	43,672,485
Investment in partnerships, at equity	659,399	782,587
Other	247,157	247,157
Total assets	$ 54,186,362	$ 49,402,534
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 825,941	$ 552,201
Accrued liabilities:		
Deferred compensation	864,333	519,783
Interest	30,936	40,213
Other	182,382	121,972
Income taxes payable	-	130,788
Long-term debt due within one year	2,000,004	2,000,004
Total current liabilities	3,903,596	3,364,961
Long-term debt	8,516,657	12,666,661
Deferred income taxes	12,249,000	10,315,000
Asset retirement obligation and other noncurrent liabilities	816,594	528,227
Stockholders' equity:		
Class A voting common stock, $.0166 par value; 12,000,000 shares authorized, 4,189,783 issued and outstanding (4,158,846 in 2003)	69,830	69,637
Capital in excess of par value	1,286,850	1,091,886
Retained earnings	27,343,835	21,366,162
Total stockholders' equity	28,700,515	22,527,685
Total liabilities and stockholders' equity	$ 54,186,362	$ 49,402,534

See accompanying notes.

Consolidated Statements of Income

	Year ended September 30, 2004	2003	2002
Revenues:			
Oil and gas sales	$23,578,615	$22,098,198	$13,080,754
Lease bonuses and rentals	115,938	72,765	41,497
Interest	5,436	13,580	36,743
Income from partnerships and other	906,620	271,495	432,403
	24,606,609	22,456,038	13,591,397
Costs and expenses:			
Lease operating expenses and production taxes	4,098,124	4,013,572	3,001,449
Exploration costs	236,939	469,224	417,971
Depreciation, depletion, and amortization	6,115,500	5,783,457	5,845,779
Provision for impairment	841,687	692,220	1,116,234
General and administrative	3,033,437	2,666,177	2,263,908
Interest expense	488,097	699,266	895,997
	14,813,784	14,323,916	13,541,338
Income before provision for income taxes and cumulative effect of accounting change	9,792,825	8,132,122	50,059
Provision (benefit) for income taxes	3,063,000	2,217,000	(293,000)
Net income before cumulative effect of accounting change	6,729,825	5,915,122	343,059
Cumulative effect of accounting changes, net of taxes of $28,500	–	46,500	–
Net income	$ 6,729,825	$ 5,961,622	$ 343,059
Basic earnings per common share:			
Income before cumulative effect of accounting change	$ 1.61	$ 1.42	$ .08
Cumulative effect of accounting change	–	.01	–
Net income	1.61	1.43	.08
Diluted earnings per common share:			
Income before cumulative effect of accounting change	1.59	1.41	.08
Cumulative effect of accounting change	–	.01	–
Net income	$ 1.59	$ 1.42	$ .08

See accompanying notes.

Consolidated Statements of Stockholders' Equity

	Common Stock Shares	Common Stock Amount	Capital in Excess of Par Value	Retained 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

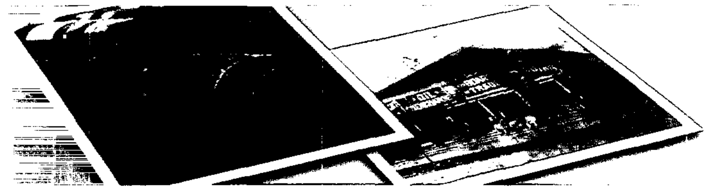
See accompanying notes.

PANHANDLE ROYALTY COMPANY

Consolidated Statements of Cash Flows

	Year ended September 30, 2004	2003	2002
Operating Activities			
Net income	$ 6,729,825	$ 5,961,622	$ 343,059
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of accounting change	–	(46,500)	–
Depreciation, depletion, amortization, and impairment	6,957,186	6,475,677	6,962,013
Deferred income taxes	1,920,000	1,676,000	(453,000)
Deferred lease bonus	288,028	67,673	8,744
Exploration costs	236,939	469,224	417,971
Gain on sale of assets	(6,959)	(38,378)	(179,037)
Equity in earnings of partnerships	(246,573)	(133,836)	(77,015)
Common stock issued to Employee Stock Ownership Plan/Directors for Services	195,156	152,898	118,684
Cash provided (used) by changes in assets and liabilities, net of amounts acquired in Wood Oil acquisition:			
Oil and gas sales and other receivables	(1,121,476)	(1,456,628)	191,908
Prepaid expenses and other	96,893	(111,713)	655,501
Accounts payable and accrued liabilities	669,422	61,604	(517,696)
Income taxes payable	(203,141)	120,725	10,063
Total adjustments	8,785,475	7,236,746	7,138,136
Net cash provided by operating activities	15,515,300	13,198,368	7,481,195
Investing Activities			
Capital expenditures, including dry hole costs	(10,946,471)	(9,195,916)	(6,967,767)
Acquisition of Wood, net of cash acquired		–	(15,229,466)
Distributions received from partnerships	369,761	252,856	191,685
Investment in partnerships	–	(45,000)	(90,000)
Proceeds from sale of assets	12,903	76,772	1,371,272
Net cash used in investing activities	(10,563,807)	(8,911,288)	(20,724,276)
Financing Activities			
Borrowings under debt agreement	6,825,000	1,525,000	18,100,000
Payments of loan principal	(10,975,004)	(4,878,335)	(4,130,000)
Purchase and cancellation of common shares	–	(778)	(4,110)
Payments of dividends	(752,152)	(582,797)	(578,943)
Net cash provided by (used in) financing activities	(4,902,156)	(3,936,910)	13,386,947
Increase (decrease) in cash and cash equivalents	49,337	350,170	143,866
Cash and cash equivalents at beginning of year	593,006	242,836	98,970
Cash and cash equivalents at end of year	$ 642,343	$ 593,006	$ 242,836
Supplemental Disclosures of Cash Flow Information			
Interest paid	$ 496,441	$ 727,153	$ 829,430
Income taxes paid, net of refunds received	$ 1,344,321	$ 456,338	$ (215,687)

See accompanying notes.



September 30, 2004, 2003 and 2002

1. Summary of Significant Accounting Policies

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.

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, 2004 and 2003, 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 significant credit losses in prior years and is not aware of any significant uncollectible accounts at September 30, 2004.

1. Summary of Significant Accounting Policies (continued)

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 $6,593,777 at September 30, 2004, consisting of perpetual ownership of mineral interests in several states, including Oklahoma, Texas and New Mexico. These costs are being amortized over a 33-year period using the straight-line method. An ultimate determination of whether these properties contain recoverable reserves in economical quantities is expected to be made within this time frame. Impairment of non-producing oil and gas properties is recognized based on experience and management judgment.

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 $841,687, $692,220, and $1,116,234 respectively, for 2004, 2003 and 2002. The majority of the impairment recognized in these years relates to fields comprised of a small number of properties or single wells on which the Company does not expect sufficient future net cash flow to recover its carrying cost.

1. Summary of Significant Accounting Policies (continued)

Asset Retirement Obligations

The adoption of SFAS No. 143 on October 1, 2002, resulted in a net increase to Property and Equipment and Asset Retirement Obligations of approximately $481,000 and $406,000, respectively, as a result of the Company separately accounting for salvage values and recording the estimated fair value of its plugging and abandonment obligations on the balance sheet. The increase in expense resulting from the accretion of the asset retirement obligation and the depreciation of the additional capitalized well costs was substantially offset by the decrease in depreciation from the Company's consideration of the estimated salvage values in the calculation. At September 30, 2004, the net increase to Property and Equipment had increased to $728,037 and the Asset Retirement Obligation increased to $602,979.

Environmental Costs

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, 2004, there were no such costs accrued.

Earnings Per Share of Common Stock

Basic earnings per share (EPS) is calculated using net income divided by the weighted average of common shares outstanding 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 5).

Stock-based Compensation

The Company applies APB Opinion No. 25 in accounting for its Deferred Compensation Plan for Outside Directors. Under APB No. 25, compensation cost is recognized for changes in the fair value of the stock credited to each director's account at the fair market value of the stock at the date of grant. The shares are then adjusted for changes in the shares' market value subsequent to the date of grant until the conversion date (see Note 7).

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 the 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 approximated market rates at September 30, 2004; the remaining borrowings bear interest at a variable rate.

2. Acquisition of Wood Oil Company

On October 1, 2001, the Company acquired 100% of the outstanding common stock of Wood Oil Company (Wood). The acquisition was made pursuant to an Agreement and Plan of Merger among the Company, PHC, Inc., and Wood Oil Company, dated August 9, 2001. 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 owned an office building in Tulsa, Oklahoma. Subsequent to the acquisition, Wood has continued to operate as a subsidiary of Panhandle and personnel were moved to Oklahoma City in early 2002. Wood and its shareholders were unrelated parties to Panhandle.

The Company's decision to acquire Wood was the result of desired growth in the Company's asset base of producing oil and gas reserves and fee mineral acreage. Wood's oil and gas activity, fee minerals and operating philosophy, in general, had been very similar to the Company's.

Wood's mineral acreage ownership and leasehold position as well as its producing oil and gas properties are located in the same general areas as the Company's. In several cases, both companies owned interests in existing producing wells and several developing fields. The Company intends to actively pursue drilling opportunities on Wood's properties.

Funding for the acquisition was obtained from BancFirst of Oklahoma City, Oklahoma, in the form of a $20 million five-year term loan. Three million of Wood's cash was used to reduce Panhandle's debt on the date of closing.

The operations of Wood, since October 1, 2001, are included in the accompanying consolidated financial statements.

3. Income Taxes

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

	2004	*2003*	*2002*
Current:			
Federal	$ 1,113,000	$ 521,000	$ 150,000
State	30,000	20,000	10,000
	1,143,000	541,000	160,000
Deferred:			
Federal	1,851,000	1,607,000	(390,000)
State	69,000	69,000	(63,000)
	1,920,000	1,676,000	(453,000)
	$ 3,063,000	$ 2,217,000	$ (293,000)

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:

	2004	*2003*	*2002*
Provision for income taxes at statutory rate	$ 3,329,561	$ 2,762,324	$ 17,521
Percentage depletion	(334,365)	(653,947)	(201,600)
Tight-sands gas credits	–	(20,000)	(77,404)
State income taxes, net of federal benefit	64,350	57,850	(34,419)
Other	3,454	70,773	2,902
	$ 3,063,000	$ 2,217,000	$ (293,000)

3. Income Taxes (continued)

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

	2004	*2003*
Deferred tax liabilities:		
Financial basis in excess of tax basis, including intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$ 12,843,000	$ 11,744,000
Deferred tax assets:		
Percentage depletion and alternative minimum tax credit, and state net operating loss carry forwards	233,000	991,000
Financial charges which are deferred for tax purposes	361,000	438,000
	594,000	1,429,000
Net deferred tax liabilities	$ 12,249,000	$ 10,315,000

4. Long-Term Debt

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

	2004	*2003*
Revolving line of credit	$ 3,350,000	$ 5,500,000
Term loan	7,166,661	9,166,665
	10,516,661	14,666,665
Current maturities of long-term debt	2,000,004	2,000,004
	$ 8,516,657	$ 12,666,661

On March 25, 2003, 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, 2006. Monthly payments on the term loan

4. Long-Term Debt (continued)

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 3/4% (4.0% at September 30, 2004) or LIBOR (for one, three or six month periods), plus 1.80%. The Company, at September 30, 2004, has elected the prime rate option.

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, 2004. 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, 2004, the Company was in compliance with the covenants.

The amount of required principal payments for the next five years as of September 30, 2004, are as follows: 2005–$2,000,004, 2006–$5,350,004, 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).

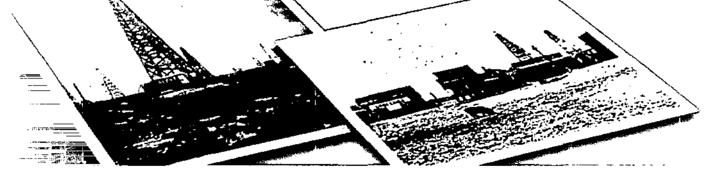
	Year ended September 30,		
	2004	*2003*	*2002*
Numerator for primary and diluted earnings per share:			
Net income	$6,729,825	$5,961,622	$ 343,059
Denominator:			
For basic earnings per share — weighted average shares	4,178,783	4,162,744	4,135,744
Effect of potential diluted shares:			
Directors' deferred compensation shares	50,018	44,682	44,200
Denominator for diluted earnings per share — adjusted weighted average shares and potential shares	4,228,801	4,207,426	4,179,944

The weighted average shares outstanding, potentially dilutive shares, and earnings per share for 2002 and 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 substantially 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 2004, 2003 or 2002) 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 249,847 shares of the Company's common stock held by the plan as of September 30, 2004, are allocated to individual participant accounts, are included in the weighted average shares outstanding for purposes of earnings per share computations and receive dividends. Contributions to the plan consisted of:

Year	*Shares*	*Amount*
2004	10,058	$ 173,125
2003	13,822	$ 156,978
2002	16,314	$ 118,684



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 meeting fees and board committee meeting fees. These shares are unissued and vest at the date of grant. The shares are credited to each director's deferred fee account at the fair market value of the stock at the date of grant and are adjusted for changes in market value subsequent thereto. 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, 2004, 50,251 shares (45,816 shares at September 30, 2003) are included in the Plan. The Company has accrued $864,334 at September 30, 2004 ($519,783 at September 30, 2003) in connection with the Plan ($344,551, $241,673 and $23,095 was charged to the results of operations for the years ended September 30, 2004, 2003 and 2002, respectively, and is included in general and administrative expense in the accompanying income statement).

9. Information on Oil and Gas Producing Activities

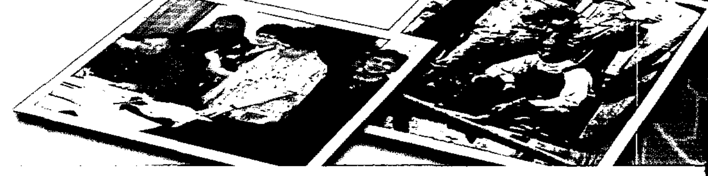
All oil and gas producing activities of the Company are conducted within the United States (principally in Oklahoma) and represent substantially all of the business activities of the Company.

During 2004, 2003 and 2002 approximately 10%, 14%, and 17%, respectively, of the Company's total revenues were derived from gas sales to ONEOK, Inc. The Company also has interests in a field of properties, the production on which accounted for approximately 7%, 9%, and 12% of the Company's revenues in 2004, 2003 and 2002, respectively.

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:

	2004	*2003*
Producing properties	$ 74,928,073	$ 65,342,062
Non-producing properties	9,790,377	9,610,757
	84,718,450	74,952,819
Accumulated depreciation, depletion and amortization	(37,424,995)	(31,386,538)
Net capitalized costs	$ 47,293,455	$ 43,566,281



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

Costs Incurred

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

	2004	*2003*	*2002*
Property acquisition costs (A)	$ 612,392	$ 127,058	$ 219,306
Exploration costs	1,239,217	1,412,653	1,080,951
Development costs	9,005,341	7,818,988	5,637,430
	$10,856,950	$ 9,358,699	$ 6,937,687

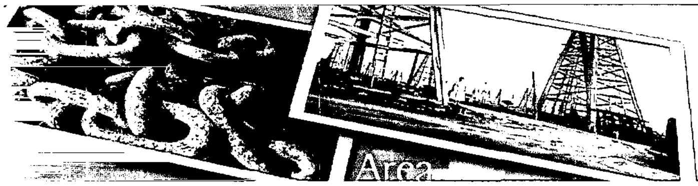
(A) Excludes Wood Oil acquisition in 2002 as set forth in Note 2, the cost of which, net of cash acquired, was $15,229,466.

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 directs its consulting petroleum engineering firm to include proved undeveloped reserves in certain areas of Oklahoma and New Mexico in the scope of properties which are evaluated for the Company.

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, 2004, 2003 and 2002, 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, 2004, 2003 and 2002. 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)

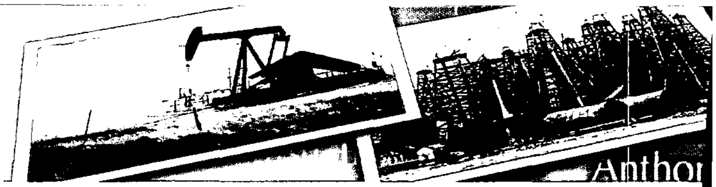
Estimated Quantities of Proved Oil and Gas Reserves

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

	Proved Reserves	
	Oil (Mbarrels)	*Gas (Mmcf)*
September 30, 2001	676	17,688
Revisions of previous estimates	(38)	745
Purchases of reserves in place	487	8,519
Extensions and discoveries	123	5,061
Production	(133)	(3,897)
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

	Proved Developed Reserves		*Proved Undeveloped Reserves*	
	Oil (Mbarrels)	*Gas (Mmcf)*	*Oil (Mbarrels)*	*Gas (Mmcf)*
September 30, 2001	413	13,236	263	4,452
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

The above reserve numbers exclude approximately 1.2 mmcf of CO2 gas reserves for years ended September 30, 2004, 2003 and 2002.



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

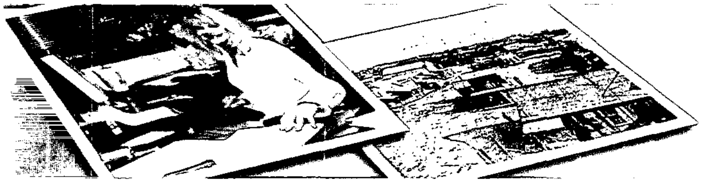
Standardized Measure of Discounted Future Net Cash Flows

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 (i) 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 and (ii) reducing the amount in (i) for estimated tax credits to be realized in the future for gas produced from "tight-sands" through December 31, 2002.

	2004	*2003*	*2002*
Future cash inflows	$187,769,949	$148,633,837	$123,668,010
Future production costs	35,447,026	29,036,188	25,022,170
Future development costs	3,716,299	3,856,341	3,991,185
Asset retirement obligation	728,037	508,362	–
Future net cash inflows before future income tax expenses	147,878,587	115,232,946	94,654,655
Future income tax expense	40,959,776	31,554,746	25,831,291
Future net cash flows	106,918,811	83,678,200	68,823,364
10% annual discount	37,768,822	29,937,664	24,878,417
Standardized measure of discounted future net cash flows	$ 69,149,989	$ 53,740,536	$ 43,944,947

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

	2004	*2003*	*2002*
Beginning of year	$ 53,740,536	$ 43,944,947	$ 17,629,945
Changes resulting from:			
Sales of oil and gas, net of production costs	(19,480,491)	(18,084,626)	(10,079,305)
Net change in sales prices and production costs	23,317,917	20,300,852	15,794,503
Net change in future development costs	91,349	87,405	(665,685)
Net change in asset retirement obligation	(144,078)	(331,601)	–
Extensions and discoveries	20,153,689	15,315,189	10,313,163
Revisions of quantity estimates	(8,026,019)	(8,291,358)	885,028
Purchases of reserves-in-place	–	–	19,370,609
Accretion of discount	7,516,647	6,135,420	2,412,266
Net change in income taxes	(6,413,806)	(4,032,361)	(10,933,161)
Change in timing and other, net	(1,605,755)	(1,303,331)	(782,416)
Net change	15,409,453	9,795,589	26,315,002
End of year	$ 69,149,989	$ 53,740,536	$ 43,944,947



11. Quarterly Results of Operations (Unaudited)

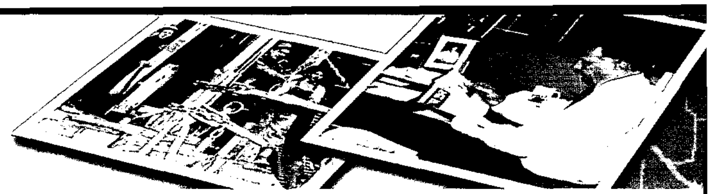
The following is a summary of the Company's unaudited quarterly results of operations.

	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 (loss) before provision for income taxes	1,402,233	2,705,868	3,374,484	2,310,240
Net income (loss)	$ 990,233	$ 1,897,637	$ 2,130,484	$ 1,711,471
Basic earnings (loss) per share	$ .24	$ .45	$ .51	$ .41
Diluted earnings (loss) per share	$ .24	$ .45	$ .50	$ .40

	Fiscal 2003 Quarter Ended			
	December 31	*March 31*	*June 30*	*September 30*
Revenues	$ 4,463,748	$ 6,980,939	$ 5,662,139	$ 5,349,212
Income before provision for income taxes and cumulative effect of accounting change	829,981	3,323,674	2,193,583	1,777,244
Income before cumulative effect of accounting change	604,981	2,320,674	1,538,583	1,443,244
Net income	$ 651,481	$ 2,320,674	$ 1,538,583	$ 1,450,884
Basic earnings per share	$ .16	$ .56	$ .37	$ .35
Diluted earnings per share	$ .15	$ .55	$ .37	$ .34

PANHANDLE ROYALTY COMPANY

Board of Directors



Bruce M. Bell
Post Oak Oil Company

E. Chris Kauffman
Campbell-Kauffman Insurance Agency

Robert O. Lorenz
Retired

H.W. Peace II
President and Chief Executive Officer

Robert A. Reece
Attorney

Robert E. Robotti
Robotti & Company, LLC

Jerry L. Smith
Chairman of the Board
Smith Capital Corporation

H. Grant Swartzwelder
Petrogrowth Advisors

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

Historic photographs: Texas Energy Museum, Beaumont, TX

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 available upon request made to:

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