PANHANDLE OIL & GAS INC
Form 10-K
December 09, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
Annual Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended September 30, 2009
Commission File Number: 001-31759
PANHANDLE OIL AND GAS INC.
(Exact name of registrant as specified in its charter)

OKLAHOMA	73-1055775
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Grand Centre, Suite 300, 5400 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)	NEW YORK STOCK EXCHANGE
(Title of Class)	(Name of each exchange on which registered)

Securities registered under Section 12(g) of the Act:
(Title of Class)
CLASS B COMMON STOCK (NON-VOTING) $1.00 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
o Yes þ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
o Yes þ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
þ Yes o No

(Facing Sheet Continued)

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files.
o Yes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o	Smaller reporting company o

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

o Yes þ 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, 2009, was $124,477,620. As of December 1, 2009, 8,311,636 shares of Class A Common stock were outstanding.

Documents Incorporated By Reference

The information required by Part III of this Report, to the extent not set forth herein, is incorporated by reference from the registrant s Definitive Proxy Statement relating to the annual meeting of stockholders to be held on March 4, 2010, 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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The following defined terms are used in this report:

SEC means the United States Securities and Exchange Commission;

Bbl means barrel;

Bcf means billion cubic feet;

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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;
CO2 means carbon dioxide;
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;
net wells or acres are determined by multiplying gross wells or acres by the Company s net revenue interest in such wells or acres;
Minerals , **mineral acres** or **mineral interests** refers to fee mineral acreage owned in perpetuity by the Company;
Working Interest refers to well interests in which the Company pays a share of the costs to drill, complete and operate a well and receives a proportionate share of production;
Royalty Interest refers to well interests in which the Company does not pay a share of the costs to drill, complete and operate a well, but receives a much smaller proportionate share (as compared to a working interest) of production;
ESOP refers to the Panhandle Oil and Gas Inc. Employee Stock Ownership and 401(k) Plan, a tax qualified, defined contribution plan.

Fiscal year references

All references to years in this report, unless otherwise noted, refer to the Company s fiscal year end of September 30.

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PART I

ITEM 1 BUSINESS

GENERAL

Panhandle Oil and Gas Inc. (Panhandle or the Company) is an Oklahoma corporation organized in 1926 as Panhandle Cooperative Royalty Company. In 1979, Panhandle Cooperative Royalty Company was merged into Panhandle Royalty Company. In February 2004, the Company increased its authorized Class A Common Stock to 12,000,000 shares and split the shares on a two-for-one basis. In January 2006, the Class A Common Stock was again split on a two-for-one basis. In March 2007, the Company increased its authorized Class A Common Stock to the current 24,000,000 shares and changed its name to Panhandle Oil and Gas Inc.

The Company is involved in the acquisition, management and development of oil and natural gas properties, including wells located on the Company s mineral acreage. Panhandle s mineral properties and other oil and natural gas interests are located primarily in Arkansas, Kansas, Oklahoma, New Mexico and Texas. Properties are also located in seven other states. The majority of the Company s oil and natural gas production is from wells located in Oklahoma.

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

The Company files periodic SEC reports on Forms 10-Q and 10-K. These Forms, the Company s annual report to shareholders and current press releases are available free of charge through its website as soon as reasonably practicable after they are filed electronically with the SEC. In addition, posted on the website are copies of the Company s various corporate governance documents. From time to time, other important disclosures to investors are provided by posting them in the Press Release or Upcoming Events section of the website, as allowed by SEC rules.

Materials filed with the SEC may be read and copied at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet website at www.sec.gov that contains reports, proxy and information statements, and other information regarding the Company that has been filed electronically with the SEC.

BUSINESS STRATEGY

Typically, over 90% of Panhandle s revenues are derived from the production and sale of oil and natural gas. See Item 8 Financial Statements . The Company s oil and natural gas holdings, including its mineral acreage, leasehold acreage and working and royalty interests in producing wells are mainly in Oklahoma with other significant holdings in Arkansas, Kansas, New Mexico and Texas. See Item 2 Description of Properties . Exploration and development of the Company s oil and natural gas properties are conducted in association with operating oil and natural gas companies, primarily larger independent companies. The Company does not operate any of its oil and natural gas properties, but has been an active working interest participant for many years in wells drilled on the Company s mineral properties and on third party drilling prospects. A significant percentage of the Company s recent drilling participations have been on properties in which the Company has mineral acreage and, in many cases, already owns an interest in a producing well in the unit. Most of these wells are in unconventional plays (shale gas) located in Oklahoma and Arkansas.

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PRINCIPAL PRODUCTS AND MARKETS

The Company s principal products are natural gas and to a lesser extent crude oil. These products are sold to various purchasers, including pipeline and marketing companies, which service the areas where the Company s producing wells are located. Since the Company does not operate any of the properties in which it owns an interest, it relies on the operating expertise of numerous companies that operate in the areas where the Company owns interests. This expertise includes the drilling and completion of new wells, producing well operations and, in most cases, the marketing or purchasing of the well s production. Natural gas sales are principally handled by the well operator and are normally contracted on a monthly basis with third party natural gas marketers and pipeline companies. Payment for natural gas sold is received by the Company either from the contracted purchasers or the well operator. Crude oil sales are generally handled by the well operator and payment for oil sold is received by the Company from the well operator or from the crude oil purchaser.

Prices of oil and natural gas are dependent on numerous factors beyond the control of the Company, such as competition, weather, international events and circumstances, supply and demand, actions taken by the Organization of Petroleum Exporting Countries (OPEC), and economic, political and regulatory developments. Since demand for natural gas is generally highest during winter months, prices received for the Company s natural gas are subject to seasonal variations.

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

COMPETITIVE BUSINESS CONDITIONS

The oil and natural gas industry is highly competitive, particularly in the search for new oil and natural gas reserves. 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 natural gas production, business and consumer demand for refined oil products and natural gas, and the effects of federal and state regulation of the exploration for, production of and sales of oil and natural gas. Changes in existing economic conditions, weather patterns and actions taken by OPEC and other oil-producing countries have dramatic influence on the price Panhandle receives for its oil and natural gas production.

The Company does not operate any of the wells in which it has an interest; rather it relies on companies with greater resources, staff, equipment, research, and experience for operation of wells both in the drilling and production phases. The Company uses its strong financial base and its mineral and leasehold acreage ownership, coupled with its own geologic and economic evaluations, to participate in drilling operations with these larger companies. This 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 recoverable oil and natural gas reserves in commercial quantities is essential to the ultimate realization of value from the Company s mineral and leasehold acreage. These mineral properties and leasehold acreage are the raw materials to its business. The production and sale of oil and

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natural gas from the Company s properties is essential to provide the cash flow necessary to sustain the ongoing viability of the Company. The Company reinvests a portion of its cash flow to purchase oil and natural gas 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 natural gas. This participation in exploration and production activities and purchase of additional acreage is necessary to continue to supply the Company with the raw materials with which to generate additional cash flow. Mineral and leasehold acreage purchases are made from many owners, and the Company does not rely on any particular companies or individuals for these purchases.

MAJOR CUSTOMERS

The Company s oil and natural gas production is sold, in most cases, through the well operators to many different purchasers on a well-by-well basis. During 2009, sales through three separate operators accounted for approximately 20%, 17% and 14%, respectively, of the Company s total oil and natural gas sales. Generally, if one purchaser declines to continue purchasing the Company s oil and natural gas, several other purchasers can be located. Pricing is generally consistent from purchaser to purchaser.

PATENTS, TRADEMARKS, LICENSES, FRANCHISES AND ROYALTY AGREEMENTS

The Company does not own any patents, trademarks, licenses or franchises. Royalty agreements on producing oil and natural gas wells stemming from the Company s ownership of mineral acreage generate a portion of the Company s revenues. These royalties are tied to ownership of mineral acreage and this ownership is perpetual, unless sold by the Company. Royalties are due and payable to the Company whenever oil and/or natural gas is produced from wells located on the Company s mineral acreage.

REGULATION

All of the Company s well interests and non-producing properties are located onshore in the United States. Oil and natural gas production is subject to various taxes, such as gross production taxes and, in some cases, ad valorem taxes.

The State of Oklahoma and other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other regulations relating to the exploration and production of oil and natural gas. These states also have regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties and the regulation of spacing, plugging and abandonment of wells. As previously discussed, the well operators are relied upon by the Company to comply with governmental regulations.

Various aspects of the Company s oil and natural gas operations are regulated by agencies of the federal government. Transportation of natural gas in interstate commerce is generally regulated by the Federal Energy Regulatory Commission (FERC) pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 (NGPA). The intrastate transportation and gathering of natural gas (and operational and safety matters related thereto) may be subject to regulation by state and local governments.

FERC s jurisdiction over interstate natural gas sales was substantially modified by the NGPA under which FERC continued to regulate the maximum selling prices of certain categories of natural gas sold in first sales in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (the Decontrol Act) deregulated natural gas prices for all first sales of natural gas. Because first sales include typical wellhead sales by producers, all natural gas

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produced from the Company s natural gas properties is sold at market prices, subject to the terms of any private contracts in effect. FERC s jurisdiction over natural gas transportation was not affected by the Decontrol Act.

Sales of natural gas are affected by intrastate and interstate natural gas transportation regulation. Beginning in 1985, FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes were intended by FERC to foster competition by transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of natural gas transporters. As a result of the various omnibus rulemaking proceedings in the late 1980 s and the individual pipeline restructuring proceedings of the early to mid-1990 s, interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, FERC expanded the impact of open access regulations to intrastate commerce.

More recently, FERC has pursued other policy initiatives that have affected natural gas marketing. Most notable are: (1) permitting the large-scale divestiture of interstate pipeline-owned natural gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to the use of electronic bulletin boards and electronic data exchange by the pipelines to make 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, as currently written and interpreted, will materially hinder or adversely affect the Company s business operations; however, there can be no assurances of future events or changes in laws, or the interpretation of laws, governing our industry. Current discussions involving the governance of hydraulic fracturing in the future could have an impact on the Company. Since the Company does not operate any wells in which it owns an interest, actual compliance with environmental laws is controlled by the well operators, with Panhandle being responsible for its proportionate share of the costs involved. As such, to its knowledge, the Company believes the well operators to be in compliance with existing regulations and that, absent an extraordinary event, any noncompliance will not have a material adverse effect on the Company. Although the Company is not fully insured against all environmental risks, insurance is maintained which is customary in the industry.

EMPLOYEES

At September 30, 2009, Panhandle employed 17 persons on a full-time basis. Five of the employees are executive officers and the President and CEO is also a director of the Company.

RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating the Company s business and future prospects. The risk factors described below are not necessarily exhaustive and investors are encouraged to perform their own investigation with respect to the Company and its business. Investors should also read the other information in this Form 10-K, including the financial statements and related notes.

Worldwide and in the United States, economic recession has existed for over a year and is continuing to have a negative effect on demand for and the price of oil and natural gas, drilling activity to explore for new reserves and availability of capital through either debt or equity markets.

Further negative effects of the current economic recession could be a decline of reserves due to curtailed drilling activity, the risk of insolvency of well operators and oil and natural gas purchasers, limited availability of certain insurance contracts and limited access to derivative instruments.

Oil and natural gas prices are volatile. Volatility in oil and natural gas prices can adversely affect results and the price of the Company s common stock. This volatility also makes valuation of oil and natural gas producing properties difficult and can disrupt markets.

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

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

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In recent years, oil and natural gas price volatility has become increasingly severe. Price volatility makes it difficult to budget and project the return on exploration and development projects and to estimate with precision the value of producing properties that are owned or acquired. In addition, 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.

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

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

The Company s derivative activities may reduce the cash flow received for oil and natural gas sales.

In order to manage exposure to price volatility in our natural gas, we enter into natural gas derivative contracts for a portion of our expected production. Commodity price derivatives may limit the cash flow we actually realize and therefore reduce revenues in the future. The fair value of our natural gas derivative instruments outstanding as of September 30, 2009 was a liability of $2,513,435.

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 natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and development dry holes are capitalized and amortized by property using the unit-of-production method as oil and natural gas is produced.

All long-lived assets, principally the Company s oil and natural gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset 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 natural gas reserves. Any assets held for sale are reviewed for impairment when the Company approves the plan to sell. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded. If an impairment charge is recognized, cash flow from operating activities is not impacted but net income and, consequently, shareholders equity, are reduced.

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

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It is not possible to measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, future production levels, and operating and development costs. In estimating our level of oil and natural gas reserves, we and our consulting petroleum engineering firm, Pinnacle Energy Services, L.L.C. of Oklahoma City, OK, make certain assumptions that may prove to be incorrect, including assumptions relating to the level of oil and natural gas prices, future production levels, capital expenditures, operating and development costs, the effects of regulation and availability of funds. If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly.

Our standardized measure is calculated using prices and costs in effect as of the date of estimation, less future development, production and income tax expenses, and is discounted at ten percent per annum to reflect the timing of future net revenue in accordance with the rules and regulations of the SEC. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates we make for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates and the timing of development expenditures. Further, our lack of knowledge of all individual well information known to the well operators such as incomplete well stimulation efforts, restricted production rates for various reasons and up to date well production data, etc. may cause differences in our reserve estimates.

Because we base the estimated discounted future net cash flows from our estimated proved reserves on prices and costs in effect on the day of estimate, the standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil and natural gas reserves.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the ten percent discount factor we use when calculating discounted future net cash flows in compliance with the Financial Accounting Standards Board s (FASB) statement on oil and gas producing activities disclosures may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company, or the oil and natural gas industry in general.

Failure to find or acquire additional reserves will cause reserves and production to decline materially from their current levels.

The rate of production from oil and natural gas properties generally declines as reserves are depleted. The Company s proved reserves will decline materially as reserves are produced except to the extent that the Company acquires additional properties containing proved reserves, conducts additional successful exploration and development drilling, successfully applies new technologies or identifies additional behind-pipe zones or secondary recovery reserves. Future oil and natural gas production is therefore highly dependent upon the level of success in acquiring or finding additional reserves. The above activities are conducted with well operators, as the Company does not operate any of its wells.

Drilling for oil and natural gas invariably involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. In addition, wells that are profitable may not achieve a targeted rate of return. The Company relies on the operators seismic data and other advanced technologies in identifying prospects and in conducting exploration and development activities. The seismic data and other technologies used do not allow operators to know conclusively prior to drilling a well whether oil or natural gas is present and may be commercially produced.

Cost factors can adversely affect the economics of any project, and ultimately the cost of drilling, completing and operating a well is controlled by well operators and existing market conditions. Further drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including unexpected drilling conditions, title problems, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, environmental and other governmental requirements, the cost and availability of drilling rigs, equipment and services and potentially the expected sales price to be received for oil or natural gas produced from the wells.

Oil and natural gas drilling and producing operations involve various risks.

The Company is subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including well blowouts, cratering and explosions, pipe failures, fires, abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks.

The Company maintains insurance against many potential losses or liabilities arising from well operations in accordance with customary industry practices and in amounts believed by management to be prudent. However, this insurance does not protect it against all operational risks. For example, the Company does not maintain business interruption insurance. Additionally, pollution and environmental risks generally are not fully insurable. These risks could give rise to significant uninsured costs that could have a material adverse effect upon the Company s financial results.

We cannot control activities on properties we do not operate.

The Company does not operate any of the properties in which it has an interest and has very limited ability to exercise influence over operations of these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and the limited ability to influence operations and associated costs could materially and adversely affect the realization of targeted returns on capital in drilling or acquisition activities and targeted production growth rates. The success and timing of drilling, development and exploitation activities on properties operated by others depend on a number of factors that are beyond the Company s control, including the operator s expertise and financial resources, approval of other participants for drilling wells and utilization of technology.

Shortages of oil field equipment, services, qualified personnel and resulting cost increases could adversely affect results of operations.

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

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Competition in the oil and natural gas industry is intense, and most of our competitors have greater financial and other resources than we do.

We compete in the highly competitive areas of oil and natural gas acquisition, development, exploration and production. We face intense competition from both major and independent oil and natural gas companies in each of the following areas:

- seeking to acquire desirable producing properties or new properties for future exploration;
- seeking to acquire the equipment and expertise necessary to develop and operate properties; and
- having sufficient capital to maintain drilling rights in all drilling units.

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

ITEM 1B UNRESOLVED STAFF COMMENTS

None

ITEM 2 PROPERTIES

At September 30, 2009, Panhandle s principal properties consisted of perpetual ownership of 254,560 net mineral acres, held principally in Arkansas, New Mexico, Oklahoma, Texas and eight other states. The Company also held leases on 20,360 net acres primarily in Oklahoma. At September 30, 2009, Panhandle held working interests, royalty interest or both in 4,861 producing oil and natural gas wells, and 40 wells in the process of being drilled or completed.

The Company does not have current abstracts or title opinions on all of its mineral properties and, therefore, cannot be certain that it has unencumbered title to all of these properties. In recent years, a few insignificant challenges have been made against the Company s fee title to its properties.

The Company pays ad valorem taxes on minerals owned in 12 states.

ACREAGE

Mineral Interests Owned

The following table of mineral interests owned reflects, at September 30, 2009, 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).

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State	Net Acres	Gross Acres	Net Acres Producing (1)	Gross Acres Producing (1)	Net Acres Leased to Others (2)	Gross Acres Leased to Others (2)	Net Acres Open (3)	Gross Acres Open (3)
Arkansas	10,026	45,455	3,481	13,138	6,459	32,037	86	280
Colorado	8,217	39,080					8,217	39,080
Florida	5,589	12,239					5,589	12,239
Kansas	3,082	11,816	152	1,280			2,930	10,536
Montana	1,007	17,947			11	1,599	996	16,348
North Dakota	11,179	64,286	6	240			11,173	64,046
New Mexico	57,396	174,461	1,352	7,125	380	480	55,664	166,856
Oklahoma	113,015	945,035	36,358	291,946	1,179	10,380	75,478	642,709
South Dakota	1,825	9,300					1,825	9,300
Texas	43,180	361,343	7,392	69,722	204	3,690	35,584	287,931
OTHER	44	279					44	279
Total:	**254,560**	**1,681,241**	**48,741**	**383,451**	**8,233**	**48,186**	**197,586**	**1,249,604**

(1) Producing represents the mineral acres in which Panhandle owns a royalty or working interest in a producing well.

(2) Leased represents the mineral acres owned by Panhandle that are leased to third parties but not producing.

(3) Open represents mineral acres owned by Panhandle that are not leased or in production.

Leases

The following table reflects net mineral acres leased from others, lease expiration dates, and net leased acres held by production.

State	Net Acres	Net Lease Acres Expiring				Net Acres Held by Production
		2010	2011	2012	2013	
Kansas	2,117					2,117
Oklahoma	16,371	1,949	2,154	49	1	12,218
Texas	504			3		501
Other	1,368					1,368
TOTAL	20,360	1,949	2,154	52	1	16,204

PROVED RESERVES

The following table summarizes estimates of proved reserves of oil and natural gas held by Panhandle. All proved reserves are located within the United States and are principally made up of small interests in 4,861 wells. Other than this report, the Company s reserve estimates are not filed with any other federal agency.

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	Barrels of Oil	Mcf of Natural Gas	Mcfe
Net Proved Developed Reserves			
September 30, 2009	882,987	45,036,460	50,334,382
September 30, 2008	895,430	35,970,450	41,343,030
September 30, 2007	754,866	31,016,304	35,545,500
Net Proved Undeveloped Reserves			
September 30, 2009	37,886	8,991,350	9,218,666
September 30, 2008	94,530	12,180,220	12,747,400
September 30, 2007	67,958	5,989,487	6,397,235
Net Total Proved Reserves			
September 30, 2009	920,873	54,027,810	59,553,048
September 30, 2008	989,960	48,150,670	54,090,430
September 30, 2007	822,824	37,005,791	41,942,735

Reserves for 2007 and 2008 exclude approximately 2.3 and 2.9 Bcf of CO_2 gas reserves. These reserves were sold in the fourth quarter of 2009.

The determination of reserve estimates is a function of testing and evaluating the production and development of oil and natural gas reservoirs in order to establish a production decline curve. The established production decline curves, in conjunction with estimated future oil and natural gas prices, development costs, production taxes and operating expenses, are used to estimate oil and natural gas reserve quantities and associated future net cash flows. As information is processed, over time, regarding the development of individual reservoirs and as market conditions change, estimated reserve quantities and future net cash flows will change as well. Estimated reserve quantities and future net cash flows are affected by changes in product prices, 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 quantities of petroleum from existing wells and facilities, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations. Proved undeveloped reserves are those quantities of petroleum expected to be recovered through future investment within a reasonable timeframe in a drilling unit immediately adjacent to the drilling unit containing a producing well, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations. 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 the timing of development.

The Company s net proved (including certain undeveloped reserves described above) oil and natural gas reserves, all of which are located in the United States, as of September 30, 2009, 2008 and 2007, have been estimated by the Company s consulting petroleum engineering firm, Pinnacle Energy Services, L.L.C. (Consulting Petroleum Engineer or 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, 2009, 2008 and 2007. 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.

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In December 2008, the SEC issued revised reporting requirements for oil and natural gas reserves that a company holds. Included in the new rule entitled *Modernization of Oil and Gas Reporting Requirements,* are the following changes: 1) permitting use of new technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; 2) enabling companies to additionally disclose their probable and possible reserves to investors, in addition to their proved reserves; 3) allowing previously excluded resources, such as oil sands, to be classified as oil and natural gas reserves rather than mining reserves; 4) requiring companies to report the independence and qualifications of a preparer or auditor, based on current Society of Petroleum Engineers criteria; 5) requiring the filing of reports for companies that rely on a third party to prepare reserve estimates or conduct a reserve audit; and 6) requiring companies to report oil and natural gas reserves using an average price based upon the prior 12-month period, rather than year-end prices. The new requirements are effective for registration statements filed on or after January 1, 2010, and for annual reports on Form 10K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. The Company is currently assessing the impact that adoption of this rule will have on its financial disclosures.

ESTIMATED FUTURE NET CASH FLOWS

Set forth below are estimated future net cash flows with respect to Panhandle s net proved reserves (based on the estimated units set forth in the immediately preceding table) for the year indicated, and the present value of such estimated future net cash flows, computed by applying a 10% discount factor as required by the rules and regulations of the SEC. Estimated future net cash flows have been computed by applying current prices at September 30 of each year to future production of proved reserves less estimated future expenditures to be incurred with respect to the development and production of these reserves. This pricing is required by SEC regulations. However, the amounts are net of operating costs and production taxes levied by the respective states. Prices used for determining future cash flows from oil and natural gas as of September 30, 2009, 2008, 2007 were as follows: 2009 $66.96/Bbl, $2.86/Mcf ; 2008 $97.74/Bbl, $4.51/Mcf; 2007 - $78.93/Bbl, $5.50/Mcf (these natural gas prices are representative of local pipelines in Oklahoma). These future net cash flows based on SEC pricing should not be construed as the fair market value of the Company s reserves. A market value determination would need to include many additional factors, including anticipated oil and natural gas price and production cost increases or decreases, which could affect the economic life of the properties.

Estimated Future Net Cash Flows

	9-30-09	9-30-08	9-30-07
Proved Developed	$ 131,674,245	$ 182,996,389	$ 173,797,222
Proved Undeveloped	15,372,040	31,863,340	23,046,080
Income Tax Expense	43,832,666	67,278,008	60,887,878
Total Proved	$ 103,213,619	$ 147,581,721	$ 135,955,424

10% Discounted Present Value of Estimated Future Net Cash Flows

	9-30-09	9-30-08	9-30-07
Proved Developed	$ 73,869,512	$ 104,840,854	$ 102,583,540
Proved Undeveloped	6,800,080	15,068,040	13,178,660
Income Tax Expense	26,923,084	41,896,610	39,068,713
Total Proved	$ 53,746,508	$ 78,012,284	$ 76,693,487

The future net cash flows for 9-30-08 and 9-30-07 are net of immaterial amounts of future cash flow to be received from CO_2 reserves. These reserves were sold in the fourth quarter of 2009.

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OIL AND NATURAL GAS PRODUCTION

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

	Year Ended 9-30-09	Year Ended 9-30-08	Year Ended 9-30-07
Bbls Oil	128,160	132,402	107,344
Mcf Natural Gas	9,109,988	6,928,038	5,147,343
Mcfe	9,878,948	7,722,450	5,791,407

Natural gas production includes 236,308, 193,408 and 175,175 Mcf of CO_2 sold at average prices of $.85, $.86 and $.61 per Mcf for the years ended September 30, 2009, 2008 and 2007, respectively.

AVERAGE SALES PRICES AND PRODUCTION COSTS

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

	Year Ended 9-30-09	Year Ended 9-30-08	Year Ended 9-30-07
Average Sales Price			
Per Bbl, Oil	$ 51.79	$ 103.91	$ 62.81
Per Mcf, Natural Gas	$ 3.38	$ 7.98	$ 5.97
Per Mcfe	$ 3.79	$ 8.94	$ 6.47
Average Production (lifting costs) (Per Mcfe of Natural Gas)			
(1)	$ 0.78	$ 0.86	$ 0.63
(2)	0.12	0.44	0.42
	$ 0.90	$ 1.30	$ 1.05

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

(2) Includes production taxes only.

Approximately 26% of the Company s oil and natural gas revenue is generated from royalty interests in approximately 3,500 wells. Royalty interests bear no share of the operating costs on those producing wells.

GROSS AND NET PRODUCTIVE WELLS AND DEVELOPED ACRES

The following table sets forth Panhandle s gross and net productive oil and natural gas wells as of September 30, 2009. Panhandle owns either working interests, royalty interests or both in these wells. The Company does not operate any wells.

	Gross Wells	Net Wells
Oil	986	20.78
Natural Gas	3,875	90.53
Total	4,861	111.31

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

As of September 30, 2009, Panhandle owned 383,451 gross developed mineral acres and 48,741 net developed mineral acres. Panhandle has also leased from others 137,196 gross developed acres containing 16,204 net developed acres.

UNDEVELOPED ACREAGE

As of September 30, 2009, Panhandle owned 1,297,790 gross and 205,819 net undeveloped mineral acres, and leases on 19,171 gross and 4,156 net acres.

DRILLING ACTIVITY

The following net productive development and exploratory wells and net dry development and exploratory wells in which the Company had either a working interest, a royalty interest or both were drilled and completed during the fiscal years indicated. The Company did not purchase any wells during these periods.

	Net Productive Wells	Net Dry Wells
Development Wells		
Fiscal years ended:		
September 30, 2009	8.893170	0.092978
September 30, 2008	8.120236	0.067177
September 30, 2007	6.215883	0.025393
Exploratory Wells		
Fiscal years ended:		
September 30, 2009	0.867702	0.138051
September 30, 2008	0.985659	0.083333
September 30, 2007	1.539561	0.137873
Purchased Wells		
Fiscal years ended:		
September 30, 2009	0	0
September 30, 2008	0	0
September 30, 2007	0	0

PRESENT ACTIVITIES

The following table sets forth the gross and net oil and natural gas wells drilling or testing as of September 30, 2009, in which Panhandle owns either a working interest, a royalty interest or both. These wells were not yet producing at September 30, 2009.

	Gross Wells	Net Wells
Oil	2	0.00469
Natural Gas	38	1.74808

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OTHER FACILITIES

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

SAFE HARBOR STATEMENT

This report, including information included in, or incorporated by reference from, future filings by the Company with the SEC, as well as information contained in written material, press releases and oral statements, 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 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 2010 and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of the Company.

Commodity Prices. The prices received for oil and natural gas production have a direct impact on the Company s revenues, profitability and cash flows as well as the ability to meet its projected financial and operational goals. The prices for natural gas and crude oil are dependent on a number of factors beyond the Company s control, including: the demand for oil and natural gas; weather conditions in the continental United States (which can greatly influence the demand for natural gas at any given time as well as the price we receive for such natural gas); and the ability of current distribution systems in the United States to effectively meet the demand for oil and natural gas at any given time, particularly in times of peak demand which may result because of adverse weather conditions.

Oil prices are sensitive to foreign influences based on political, social or economic factors, any one of which could have an immediate and significant effect on the price and supply of oil. In addition, prices of both natural gas and oil are becoming more and more influenced by trading on the commodities markets which, at times, has increased the volatility associated with these prices.

Uncertainty of Oil and Natural Gas Reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond the Company s control. The oil and natural gas reserve data included in this report represents only an estimate of these reserves. Oil and natural gas reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas, and assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, development costs, and workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas, and estimates of the future net cash flows from oil and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, oil and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues and expenditures with respect to oil and natural gas reserves will vary from estimates, and those variances can be material.

The Company does not operate any of the properties in which it has an interest and has very limited ability to exercise influence over operations for these properties or their associated costs. Dependence on the operator and other working interest owners for these projects and the limited ability to influence operations and associated costs could materially and adversely affect the realization of targeted returns on capital in drilling or acquisition activities and targeted production growth rates.

The information regarding discounted future net cash flows included in this report is not necessarily the current market value of the estimated oil and natural gas reserves attributable to the Company s properties. As required by the SEC, the 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 used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and the risks associated with operations of the oil and natural gas industry in general.

ITEM 3 LEGAL PROCEEDINGS

There were no material legal proceedings involving Panhandle or Wood Oil on 9/30/09 or at the date of this report.

ITEM 4 SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of Panhandle s security holders during the fourth quarter of the fiscal year ended September 30, 2009.

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PART II

ITEM 5 MARKET FOR REGISTRANTS COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

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

The above graph compares the cumulative 5-year total return provided shareholders on Panhandle Oil and Gas Inc. s common stock relative to the cumulative total returns of the S&P Smallcap 600 index and the S&P Oil & Gas Exploration & Production index. An investment of $100 (with reinvestment of all dividends) is assumed to have been made in our common stock and in each of the indexes on September 30, 2004 and its relative performance is tracked through September 30, 2009.

On July 22, 2008, the Company s Class A Common Stock (Common Stock) was listed on the New York Stock Exchange (symbol PHX) and, prior to that, it was listed on the American Stock Exchange under the same symbol. The following table sets forth the high and low trade prices of the Common Stock during the periods indicated:

Quarter Ended	High	Low
December 31, 2007	$28.41	$23.75
March 31, 2008	$31.69	$24.75
June 30, 2008	$39.90	$27.25
September 30, 2008	$39.98	$23.91
December 31, 2008	$28.18	$13.75
March 31, 2009	$23.75	$13.15
June 30, 2009	$24.62	$15.79
September 30, 2009	$28.02	$18.17

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As of November 24, 2009, there were 1,766 holders of record of Panhandle s Class A Common Stock and approximately 4,000 beneficial owners.

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

Date	Rate Per Share
December 2007	$ 0.07
March 2008	$ 0.07
June 2008	$ 0.07
September 2008	$ 0.07
December 2008	$ 0.07
March 2009	$ 0.07
June 2009	$ 0.07
September 2009	$ 0.07

Approval by the Company s board of directors is required before the declaration and payment of any dividends.

While the Company anticipates it will continue to pay dividends on its common stock, the payment and amount of future cash dividends will depend upon, among other things, financial condition, funds from operations, the level of capital and development expenditures, future business prospects, contractual restrictions and any other factors considered relevant by the board of directors.

The Company s credit facility also contains a provision limiting the paying or declaring of a cash dividend to fifteen percent of net cash flow provided by operating activities from the Consolidated Statement of Cash Flows of the preceding twelve-month period. See Note 4 to the consolidated financial statements contained herein at Item 8 Financial Statements , for a further discussion of the loan agreement.

On May 28, 2008 and July 29, 2008, the Company announced that its Board of Directors had approved stock repurchase programs to purchase up to $2,000,000 and $3,000,000 (respectively) of the Company s common stock. These programs were completed in 2008. The shares are held in treasury and are accounted for using the cost method. At September 30, 2009 and September 30, 2008, 11,508 and 7,640 (respectively) treasury shares were contributed to the Company s ESOP on behalf of the ESOP participants.

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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.

	As of and for the year ended September 30,				
	2009	2008	2007	2006	2005
Revenues					
Oil and natural gas sales	$ 37,421,688	$ 69,026,785	$ 37,449,174	$ 36,008,527	$ 30,242,210
Lease bonuses and rentals	188,906	167,559	208,625	410,984	2,214,992
Gains (losses) on nat. gas deriv. contr.	(661,828)	(940,823)	765,316		
Gain on sales of assets, int. and other	2,684,353	233,709	322,405	529,804	745,800
Income from partnerships	323,848	631,891	383,391	536,365	395,173
	39,956,967	69,119,121	39,128,911	37,485,680	33,598,175
Costs and Expenses					
Lease oper. exp and prod. taxes	8,897,235	10,055,762	6,057,456	5,262,834	4,802,595
Exploration costs	711,582	455,943	1,050,069	222,892	784,741
Depr. depl. and amortization	28,168,933	19,784,660	15,291,625	10,142,367	7,506,571
Provision for impairment	2,464,520	526,380	3,761,832	3,009,953	232,295
Loss on sales of assets		204,189	254,395	119,282	291,452
Gen. and administrative	4,866,044	5,006,512	3,877,492	3,335,899	4,545,208
Bad debt expense (recovery)	(185,272)	591,258			
Interest expense	6,946	44,346	133,578	232,234	359,527
	44,929,988	36,669,050	30,426,447	22,325,461	18,522,389
Income (loss) before provision (benefit) for income taxes	(4,973,021)	32,450,071	8,702,464	15,160,219	15,075,786
Provision (benefit) for income taxes	(2,568,000)	10,894,302	2,359,000	4,586,000	4,591,000
Net income (loss)	$ (2,405,021)	$ 21,555,769	$ 6,343,464	$ 10,574,219	$ 10,484,786
Basic Earnings per share	$ (0.29)	$ 2.54	$ 0.75	$ 1.25	$ 1.25
Diluted Earnings per share	$ (0.29)	$ 2.54	$ 0.75	$ 1.25	$ 1.24
Dividends Declared per share	$ 0.28	$ 0.28	$ 0.25	$ 0.185	$ 0.125

Weighted Average Shares Outstanding					
Basic	8,397,337	8,492,378	8,499,233	8,479,406	8,390,280
Diluted	8,397,337	8,492,378	8,499,233	8,479,406	8,450,238
Net cash provided by (used in):					
Operating activities	$ 37,650,864	$ 39,924,719	$ 28,106,500	$ 23,470,145	$ 17,909,249
Investing activities	$ (36,263,250)	$ (37,706,995)	$ (26,940,679)	$ (21,118,606)	$ (10,514,096)
Financing activities	$ (1,643,414)	$ (2,311,376)	$ (610,814)	$ (3,556,019)	$ (6,398,663)
Total assets	$ 108,549,632	$ 122,007,183	$ 78,539,797	$ 70,949,242	$ 61,241,692
Long-term debt	$ 10,384,722	$ 9,704,100	$ 4,661,471	$ 1,166,649	$ 3,166,653
Shareholders equity	$ 64,122,343	$ 68,348,901	$ 53,681,371	$ 49,065,697	$ 38,635,350

All share and per share amounts are adjusted for the effect of a 2-for-1 stock split effective in January 2006.

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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 to explore for, develop, produce and sell oil and natural gas. Results of operations are dependent primarily upon reserve quantities and associated exploration and development costs in finding new reserves, production quantities and related production costs and oil and natural gas sales prices. Worldwide economic conditions over the past year have had a negative effect on the price of oil and natural gas resulting in substantially lower revenues and reduced drilling activity. This decline in drilling activity is expected to have an adverse effect on future production levels; however, the Company does expect to have new production come on line in 2010, as 22 working interest wells were drilling or testing as of September 30, 2009 in which the Company owns an average 7% working interest. The expected production from these wells should help mitigate some of the production decline of existing wells. Lower oil and natural gas prices have also negatively impacted oil and natural gas reserve quantities and related future net cash flows, resulting in higher depreciation, depletion, amortization and impairment costs during 2009. Although drilling activity has modestly increased recently, the Company expects additions to properties and equipment for oil and natural gas activities to decrease in 2010 as compared to 2009. Additions to properties and equipment are distinct from capital expenditures in that these include cash and non-cash additions; therefore, additions to properties and equipment represent amounts added to properties and equipment in the period, whereas capital expenditures represent amounts paid in the period. Due to the Company s low debt level, combined with available capital through its bank line, we believe the Company is well positioned to quickly take advantage of any increase in drilling activity, should market prices for natural gas improve. Substantially all of the Company s drilling is currently for natural gas.

The Company had no off-line balance sheet arrangements during 2009 or prior years.

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

	For the Year Ended September 30,				
	2009	Percent Incr. or (Decr.)	2008	Percent Incr. or (Decr.)	2007
Production:					
Oil (Bbls)	128,160	-3%	132,402	23%	107,344
Natural Gas (Mcf)	9,109,988	31%	6,928,038	35%	5,147,343
Mcfe	9,878,948	28%	7,722,450	33%	5,791,407
Average Sales Price:					
Oil (per Bbl)	$ 51.79	-50%	$ 103.91	65%	$ 62.81
Natural Gas (Mcf)	$ 3.38	-58%	$ 7.98	34%	$ 5.97
Mcfe	$ 3.79	-58%	$ 8.94	38%	$ 6.47

Fiscal Year 2009 Compared to Fiscal Year 2008

Overview

The Company recorded a net loss of $2,405,021, or $.29 per share, in 2009, compared to net income of $21,555,769, or $2.54 per share, in 2008. Lower oil and natural gas prices during 2009 resulted in significantly lower total revenues in 2009 as compared to 2008, notwithstanding substantially increased production volumes. Total expenses increased in 2009 over 2008 as there were significant increases in depreciation, depletion and amortization (DD&A) and provision for impairment, which were

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partially offset by decreases in lease operating expenses and production taxes, general and administrative expenses and bad debt expense. An income tax benefit of approximately $2.6 million was incurred in 2009, whereas approximately $10.9 million of income tax expense was recognized in 2008.

Revenues

Total revenues decreased $29,162,154 or 42% for 2009 as compared to 2008. The decrease primarily was the result of a $31,605,097 decrease in oil and natural gas sales, partially offset by gains related to the sale of certain oil and natural gas properties. The decrease in oil and natural gas sales was largely due to a 50% decrease in oil prices and a 58% decrease in natural gas prices, partially offset by a 28% increase in production on a Mcfe basis. Production increased even though 2009 additions to properties and equipment for oil and natural gas activities decreased significantly compared to 2008. This occurred because many wells in which the Company owned significant working interests (as high as 42%) came on line in the latter half of 2008 and in the first quarter of 2009 (resulting in nearly a full year s production being recorded in 2009). The majority of new production which has come on line, and production anticipated to come on line from wells currently being completed and tested, is in the Company s major shale plays in the Woodford Shale in southeast Oklahoma and the Fayetteville Shale in Arkansas. During 2010, the Company expects to continue exploiting its mineral interests in these two areas as well as in the relatively new Anadarko (or Cana) Woodford Shale play in western Oklahoma where the Company owns mineral interests. Anticipated drilling activity in 2010 is expected to be lower than in 2009, thus the Company currently expects oil and natural gas production levels to decline moderately in 2010.

Production by quarter for 2009 was as follows:

First quarter	2,495,299 Mcfe
Second quarter	2,380,124 Mcfe
Third quarter	2,647,474 Mcfe
Fourth quarter	2,356,051 Mcfe
Total	9,878,948 Mcfe

Gains on Sale of Assets

During 2009, the Company sold a portion of its interest in the Southeast Leedey Field in Oklahoma and all of its interest in the McElmo Dome Unit in Colorado, the Company s sole source of CO2 production. The total proceeds from the 2009 sale of these interests were approximately $3.4 million; the combined gain was approximately $2.5 million, whereas approximately $16,000 was recorded as gain on sale of assets in 2008.

Gains (Losses) on Natural Gas Derivative Contracts

Realized and unrealized gains and losses are scheduled below:

Gains (losses) on	Fiscal year	
derivative contracts	2009	2008
Realized	$ 2,497,800	($1,480,100)
Unrealized	(3,159,628)	539,277
Total	($661,828)	($940,823)

Lease Operating Expenses (LOE) and Production Taxes

LOE increased $1,066,856 or 16% in 2009. LOE costs per Mcfe of production decreased from $.86 in 2008 to $.78 in 2009. As a result of continued drilling and completion of new wells, the Company s ownership of net wells has increased. This increase in well ownership combined with high initial LOE on newly completed wells has resulted in increased overall LOE costs. However, certain LOE costs such as transportation, compression and marketing of natural gas have gone down dramatically on a per Mcfe basis due to the much lower natural gas sales prices on which these expenses are calculated (on a percentage basis). These lower expenses plus the significant increase in total Mcfe production lowered per Mcfe costs.

Production taxes decreased $2,225,383 or 65% in 2009. The decrease is primarily the result of significantly lower oil and natural gas sales in 2009, as production taxes are paid as a percentage of sales. However, the decrease is not proportional to the sales decrease due to new horizontal wells which have come on line in Arkansas and Oklahoma which qualify for production tax credits from these states. These horizontally drilled wells are primarily in the Woodford Shale play in southeast Oklahoma and the Fayetteville Shale play in Arkansas.

Exploration Costs

Exploration costs were $711,582 in 2009 compared to $455,943 in 2008, a $255,639 increase. Expired, impaired or abandoned leasehold costs charged to exploration costs in 2009 were $169,564 more than in 2008. Five exploratory dry holes (in which the Company had very small working interests) were drilled in 2009 compared to none during 2008 resulting in an $86,075 increase in exploration costs related to exploratory dry holes.

Depreciation, Depletion and Amortization (DD&A)

Total DD&A increased $8,384,273 or 42% in 2009, while DD&A per Mcfe increased to $2.85 in 2009 as compared to $2.56 in 2008. The 28% increase in total Mcfe produced in 2009, as compared to the 2008 period, accounts for approximately $5.5 million of the overall DD&A increase. The remaining increase of approximately $2.9 million is attributable to the increase in DD&A per Mcfe which is related to lower oil and natural gas reserve volumes per well resulting from lower oil and natural gas prices (expected reserves per well decrease when oil and natural gas prices decline as the lower prices result in wells reaching their economic limits earlier in time, thus shortening the wells economic lives and increasing the DD&A rate per Mcfe of production), and the substantially higher drilling and completion costs for horizontally drilled wells, primarily in the Woodford and Fayetteville Shale areas. These same wells also account for the majority of the 2009 increase in natural gas production.

Provision for Impairment

The provision for impairment increased $1,938,140 in 2009 as compared to 2008. In 2009, thirteen fields were impaired $2,433,652, whereas in 2008 seven fields were impaired $514,180. The amount and number of fields impaired increased in 2009 as lower oil and natural gas price projections were used to calculate oil and natural gas reserves and future net cash flows as compared to 2008. These lower price projections resulted in lower future net cash flows and lower estimated fair value, which is used to test each field for impairment.

Loss on Sale of Assets

Loss on sale of assets decreased $204,189 in 2009 as compared to 2008. Two low performing wells in western Oklahoma were sold in 2008 at a loss, while none were sold at a loss in 2009.

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General and Administrative Costs (G&A)

G&A decreased $140,468 or 3% in 2009 due to decreased personnel related costs of approximately $229,000, which included a decrease in employee bonus costs of approximately $500,000 in the 2009 period (the result of beginning to ratably accrue for estimated 2008 annual employee bonuses during the 2008 fiscal period due to specific bonus performance criteria being established plus recording the full 2007 annual discretionary bonuses approved and paid during the 2008 fiscal period), partially offset by increases in legal fees of approximately $106,000.

Bad Debt Expense (Recovery)

Bad debt expense decreased $776,530 in 2009 as compared to 2008. On July 22, 2008, SemGroup, L.P. and certain subsidiaries (SemGroup) filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy code. All of the 2008 bad debt expense of $591,258 represents over 80% of the total amount owed the Company directly and indirectly, through the operators of the affected wells where SemGroup was the purchaser of oil. On October 28, 2009, the U.S. Bankruptcy Court confirmed the Fourth Amended Joint Plan of Affiliated Debtors which set forth various settlement details for producers and interest owners. Based on the details of the plan, discussion with operators impacted and management s judgment, the Company has lowered the reserve for doubtful accounts to $405,129 at September 30, 2009, resulting in $186,129 of bad debt recovery.

Provision (Benefit) for Income Taxes

In 2009, the Company recorded a benefit for income taxes of $2,568,000 as a result of a pre-tax loss of $4,973,021 as compared to a provision for income taxes of $10,894,302 in the 2008 period as a result of pre-tax income of $32,450,071. The resulting effective tax benefit rate in 2009 was 52% as compared to an effective tax provision rate of 34% in 2008. The Company s utilization of excess percentage depletion (which is a permanent tax benefit) increased the tax benefit in the 2009 period, whereas it decreased the provision for income taxes in the 2008 period. The effect of this permanent tax benefit is that the effective tax rate is increased when recording a benefit for income taxes as in the 2009 period, while reducing the effective tax rate when recording a provision for income taxes as in the 2008 period. The benefit of excess percentage depletion is not directly related to the amount of a recorded loss or income. Accordingly, in cases where a recorded loss or income is relatively small, the proportional effect of the excess percentage depletion on the effective tax rate may become significant.

With the decline in product prices and the loss in 2009, the Company established a valuation allowance on certain state tax net operating loss carryforwards (NOLs) for which the Company no longer believes are more likely than not to be realized prior to expiration. This reduced the benefit recognized during 2009 by $278,000.

Liquidity and Capital Resources

At September 30, 2009, the Company had positive working capital of $3,436,692, as compared to positive working capital of $4,603,467 at September 30, 2008. The decrease in working capital resulted from decreases in oil and natural gas sales receivables, and refundable income taxes, a change in short-term derivative contracts from an asset in 2008 to a liability in 2009, partially offset by a decrease in accounts payable. Significantly lower oil and natural gas sales prices received during 2009 have greatly reduced the Company s receivables from the sale of oil and natural gas. The lower 2009 oil and natural gas sales prices have also been the main factor in decreased drilling activity, thus reducing the Company s accounts payable for drilling costs. A substantial amount of the payments made for capital expenditures in 2009 was for wells committed to, or which began drilling in 2008. Refundable income taxes declined as the Company s 2008 refund due was received during the quarter ended March 31, 2009.

The Company s 2009 operating cash flow decreased 6% to $37,650,864 as compared to 2008. 2009 net cash provided by operating activities, as compared to 2008, decreased primarily as a result of a recorded net loss of $2,405,021 in 2009 as compared to net income of $21,555,769 in 2008, partially offset by the net positive effect to cash flow from operations of decreases in oil and natural gas sales receivables, derivative contracts and refundable income taxes and increases in gain on sale of assets and depreciation, depletion, amortization and impairment, partially offset by a decrease in deferred income taxes. Additions to properties and equipment for oil and natural gas activities during the 2009 period were $28,540,290 as compared to $52,812,138 in the 2008 period. Additions to properties and equipment are distinct from capital expenditures in that these include cash and non-cash additions; therefore, additions to properties and equipment represent amounts added to properties and equipment in the period, whereas capital expenditures represent amounts paid in the period. Management expects relatively depressed natural gas prices to continue through much of 2010, resulting in continued reduced drilling activity. The expected result is property and equipment additions for oil and natural gas activities in 2010 will be somewhat lower to near the level of 2009. Management expects oil prices to remain relatively stable through 2010; however, since over 80% of the Company s sales are from the sale of natural gas, oil prices have a marginal effect on the Company s cash flows. The Company does not operate any of its oil and natural gas properties and cannot control drilling activity on its mineral and leasehold acreage; thus, low natural gas prices will likely continue to have a negative impact on the Company s drilling activity, making it extremely difficult for the Company to predict additions to properties and equipment with certainty. Therefore, based on management s assessment of current conditions, 2010 additions to property and equipment for oil and natural gas activities are projected to be in the mid-$20 million range, as compared to approximately $28 million in 2009.

The industry-wide decline in drilling activity has created downward pressure on the costs for drilling rigs, well equipment, and well services, which has reduced the overall costs of drilling and completing wells. Also, as lower natural gas prices continue to put downward pressure on drilling activity, and resulting production declines of natural gas occur, supply and demand of natural gas is expected to eventually balance resulting in a more stabilized natural gas price.

The Company historically has funded capital additions, overhead costs and dividend payments primarily from operating cash flow. However, due to sharp decreases in oil and natural gas prices during 2009 and the increased expenditures for drilling in the prior two years, the Company has utilized its revolving line-of-credit facility to help fund these expenditures. To minimize significant increases in borrowings, the Company s current strategy is to reduce working interest participations in certain large ownership wells or by simply taking a no cost royalty interest in certain wells. By doing so, the Company reduces its capital expenditures and thereby limits borrowings, but still receives the benefit of a relatively high net revenue interest in new wells. Even with this strategy, temporary moderate increases in borrowing can occur while the Company awaits the receipt of first revenues (which normally is 4 to 6 months after production begins) on recently completed wells. Wells that have been recently completed will provide additional cash flow to the Company in 2010 as these first payments are received. Debt levels should remain reasonably stable through 2010 as these first revenues are received and the drilling activity is managed. The Company s current borrowing base under its revolving credit facility is $35 million, providing substantial availability of funds, should the need arise.

Contractual Obligations and Commitments

The Company has a credit facility with Bank of Oklahoma (BOK) which consists of a revolving loan in the amount of $50,000,000 which is subject to a semi-annual borrowing base determination. The current borrowing base is $35,000,000. The revolving loan matures on October 31, 2011. Borrowings under the revolving loan are due at maturity. The revolving loan bears interest at the national prime rate plus a range of .50% to 1.25%, or 30 day LIBOR plus a range of 2.00% to 2.75%, with an established interest rate floor of 4.50% annually. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the loan value of the Company s oil and natural gas properties is advanced.

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Determinations of the borrowing base are made semi-annually or whenever BOK believes there has been a material change in the value of the Company s oil and natural gas properties. The loan agreement contains customary covenants which, among other things, require periodic financial and reserve reporting and limit the Company s incurrence of indebtedness, liens, dividends and acquisitions of treasury stock, and require the Company to maintain certain financial ratios. At September 30, 2009, the Company was in compliance with these covenants.

The table below summarizes the Company s contractual obligations and commitments as of September 30, 2009:

Contractual Obligations and Commitments	Payments due by period Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$ 10,384,722	$	$ 10,384,722	$	$
Building lease	$ 527,230	$ 204,089	$ 323,141	$	$

At September 30, 2009, the Company s derivative contracts were in a net liability position of $2,513,435. The ultimate settlement amounts of the derivative contracts are unknown because they are subject to continuing market risk. Please read Item 7A. Quantitative and Qualitative Disclosures about Market Risk and Note 1 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding the derivative contracts.

As of September 30, 2009, the Company s asset retirement obligations were $1,620,225. Asset retirement obligations represent the future expenditures to plug and abandon the wells when the oil and natural gas reserves are depleted. Please read Note 1 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding the Company s asset retirement obligations.

Fiscal Year 2008 Compared to Fiscal Year 2007

Overview

The Company recorded net income of $21,555,769 in 2008, compared to net income of $6,343,464 in 2007. Total revenues were significantly higher in 2008 as a result of increases in both oil and natural gas production and prices in 2008 as compared to 2007. The increase in revenue was partially offset by increases in 2008 as compared to 2007 in the following expense categories: lease operating expense; production taxes; depreciation, depletion and amortization; general and administrative expense; and provision for income taxes. Provision for impairment experienced a significant decrease in 2008 as compared to 2007.

Revenues

Total revenues increased $29,990,210 or 77% for 2008 as compared to 2007. The increase was the result of a $31,577,611 increase in oil and natural gas sales, partially offset by losses related to natural gas collar contracts of $1,706,139, which is the result of high natural gas prices from March, 2008 through July, 2008 which exceeded the ceilings of the natural gas collar contracts. Oil and natural gas sales increases were due to an overall 33% increase in Mcfe production, a 65% increase in oil prices and a 34% increase in natural gas prices. 2008 capital expenditures, net wells drilled and completed and,

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accordingly, oil and natural gas production increased, as compared to 2007. The major areas in which new wells significant to the Company have been drilled and completed are the Woodford Shale in southeast Oklahoma, the Fayetteville Shale in Arkansas and the Dill City and Yellowstone Southeast prospects in western Oklahoma.

Production by quarter for 2008 was as follows:

First quarter	1,831,206 Mcfe
Second quarter	1,727,757 Mcfe
Third quarter	1,979,904 Mcfe
Fourth quarter	2,183,583 Mcfe
Total	7,722,450 Mcfe

Gains (losses) on Natural Gas Derivative Contracts

Realized and unrealized gains and losses are scheduled below:

Gains (losses) on	Fiscal year	
derivative contracts	2008	2007
Realized	($1,480,100)	$ 658,400
Unrealized	539,277	106,916
Total	($940,823)	$ 765,316

The Company made payments of $1,480,100 under the contracts in 2008 as compared to receiving cash payments of $658,400 in 2007. The Company s fair value of derivative contracts was an asset of $646,193 as of September 30, 2008 as compared to an asset of $106,916 as of September 30, 2007.

Lease Operating Expenses and Production Taxes (LOE)

LOE increased $2,961,627 or 81% in 2008. LOE costs per Mcfe of production increased from $.63 in 2007 to $.86 in 2008. This $.23 per Mcfe increase is the result of significant increases in costs related to the transporting, compressing and marketing of natural gas. These increases account for approximately $1.9 million of the overall LOE increase and have been experienced primarily in the Woodford Shale area in southeast Oklahoma and the Dill City prospect in western Oklahoma. The remaining LOE increase of approximately $1.1 million is the result of the increased number of net wells owned that began producing in 2008 (new wells generally experience higher operating costs during the first year of production) combined with continued increases in costs of field personnel, fuel and materials on wells existing prior to 2008.

Production taxes increased $1,036,679 or 43% in 2008. The increase is primarily the result of significantly higher oil and natural gas sales in 2008, as production taxes are paid as a percentage of sales. The increase is not proportional to the sales increase due to new wells coming on line in Arkansas which has a low production tax rate and production tax credits that the Company is entitled to on production from horizontally drilled wells in Oklahoma (primarily from the Woodford Shale area in southeast Oklahoma). These production tax credits totaled approximately $467,000 in 2008.

Exploration Costs

Exploration costs decreased $594,126 in 2008 as compared to 2007. This decrease is the result of a $467,868 exploratory dry hole drilled in 2007 in Louisiana. No exploratory dry holes were drilled in

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2008. Since the Company utilizes the successful efforts method of accounting for oil and natural gas operations, only exploratory dry holes result in their costs being charged to exploration costs. Charges to exploration costs for expired or abandoned leasehold costs also decreased approximately $101,000 in 2008 as compared to 2007.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased $4,493,035 or 29% in 2008 to $2.56 per Mcfe as compared to $2.64 per Mcfe in 2007. The overall increase is the result of increased production volumes in 2008 as compared to 2007. The decrease in the DD&A rate per Mcfe is the result of higher than normal DD&A per Mcfe in 2007 resulting from downward reserve revisions on approximately fifty of the Company s working interest wells. Additional DD&A charges on those wells totaled approximately $2 million.

Provision for Impairment

The provision for impairment decreased $3,235,452 in 2008 as compared to 2007. Seven fields were impaired $514,180 in 2008 as compared to eight fields which were impaired $3,397,087 in 2007. In 2008 approximately $309,000 of impairment was on one field in western Oklahoma. In 2007 approximately $2 million of the impairment was on one field in western Oklahoma (unexpected declining production resulted in lower reserve estimates), approximately $476,000 was on one field in west Texas and approximately $390,000 was on one field in New Mexico.

Loss on Sale of Assets

Loss on sale of assets decreased $50,206 in 2008 as compared to 2007. Two low performing wells in western Oklahoma were sold in 2008 at a loss of $203,107. In 2007 several low performing wells in southeast Oklahoma were sold at a loss of $221,998.

General and Administrative Costs (G&A)

G&A costs increased $1,129,020 or 29% in 2008. The increase is principally the result of increased personnel costs of $749,110, increased professional fees of $149,303 and increased directors expenses of $89,985.

Bad Debt Expense (Recovery)

Bad debt expense increased $591,258 in 2008 as compared to 2007. On July 22, 2008 SemGroup, L.P. and certain subsidiaries (SemGroup) filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy code. All of the 2008 bad debt expense of $591,258 represents over 80% of the total amount owed the Company directly and indirectly, through the operators of the affected wells where SemGroup was the purchaser of oil. No bad debt expense was recorded in 2007.

Provision for Income Taxes

Provision for income taxes increased $8,535,302 in 2008 as compared to 2007 as a result of income before provision for income taxes increasing by $23,747,607. The Company utilizes excess percentage depletion to reduce its effective tax rate from the federal statutory rate. The effective tax rate was 33.6% for 2008 and 27.1% for 2007.

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, derivative contracts, impairment of assets, oil and natural gas sales revenue accruals, refundable production taxes and provision for income tax. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, consultants and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known. The oil and natural gas sales revenue accrual is particularly subject to estimates due to the Company s status as a non-operator on all of its properties. As such, production and price information obtained from well operators is substantially delayed. This causes the estimation of recent production and prices used in the oil and natural gas revenue accrual to be subject to future change.

Oil and Natural Gas Reserves

Management considers the estimation of the Company s crude oil and natural gas reserves to be the most significant of its judgments and estimates. These estimates affect the unaudited standardized measure disclosures, as well as DD&A and impairment calculations. Changes in crude oil and natural gas reserve estimates affect the Company s calculation of DD&A, provision for abandonment and assessment of the need for asset impairments. On an annual basis, with a semi-annual update, the Company s Consulting Petroleum Engineer, with assistance from Company staff, prepares estimates of crude oil and natural gas reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. However, when significant oil and natural gas price changes occur between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing prices current with the period. As required by the guidelines and definitions established by the SEC, these estimates are based on current crude oil and natural gas pricing held flat over the life of the properties. However, projected future crude oil and natural gas pricing assumptions are used by management to prepare estimates of crude oil and natural gas reserves and future net cash flows used in asset impairment assessments and in formulating management s overall operating decisions. Based on the Company s 2009 DD&A, a 10% change in the DD&A rate per Mcfe would result in a corresponding $2,816,893 annual change in DD&A expense. Crude oil and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management.

Successful Efforts Method of Accounting

The Company has elected to utilize the successful efforts method of accounting for its oil and natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, non producing lease impairment, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized by property using the unit-of-production method as oil and natural gas is produced. The Company s exploratory wells are all on-shore and primarily located in the midcontinent area. Generally, expenditures on exploratory wells comprise significantly less than 10% of the Company s total expenditures for oil and natural gas properties. This accounting method may yield significantly different operating results than the full cost method.

Derivative contracts

In the past, the Company entered into costless collar arrangements (all of which expired in the 2009 first quarter). Currently, the Company has entered into fixed swap contracts. Both of these instruments were intended to reduce the Company s exposure to short-term fluctuations in the price of natural gas. Collar contracts set a fixed floor price and a fixed ceiling price and provide for payments to the Company if the index price falls below the floor or require payments by the Company if the index price rises above the ceiling. Fixed swap contracts set a fixed price and provide for payments to the Company if the index price is below the fixed price, or require payments by the Company if the index price is above the fixed price.

The Company accounts for its derivative contracts under Accounting for Derivative Instruments and Hedging Activities guidance. The Company is required to recognize all derivative instruments as either assets or liabilities in the consolidated balance sheet at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines, changes in fair value are recognized in other comprehensive income (loss) until the hedged item is recognized in earnings. Hedge effectiveness is required to be measured at least quarterly based on relative changes in fair value between the derivative contract and hedged item during the period of hedge designation. The ineffective portion of a derivative s change in fair value is recognized in current earnings. For derivative instruments not designated as hedging instruments, the change in fair value is recognized in earnings during the period of change as a change in derivative fair value. At September 30, 2009, the Company had no derivative contracts designated as cash flow hedges.

Impairment of Assets

All long-lived assets, principally oil and natural gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than its estimated future net cash flows. The evaluations involve significant judgment since the results are based on estimated future events, such as inflation rates, future sales prices for oil and natural gas, future production costs, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The Company estimates future net cash flows on its oil and natural gas properties utilizing differentially adjusted forward pricing curves for both oil and natural gas and a discount rate in line with the discount rate we believe is most commonly used by the market participants (currently 10%). The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to oil and natural gas reserves. A further reduction in oil and natural gas prices (which are reviewed quarterly) or a decline in reserve volumes (which are re-evaluated semi-annually) would likely lead to additional impairment that may be material to the Company. Any assets held for sale are reviewed for impairment when the Company approves the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded. As a result of the drop in natural gas prices in 2009 from 2008 ($2.86 from $4.51), the Company recognized impairment of $2,464,520.

Non-producing oil and natural gas leases are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by

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economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties costs which the Company believes will not be transferred to proved properties over the remaining lives of the leases. Impairment loss is charged to exploration costs when recognized. As of September 30, 2009, the remaining carrying cost of non-producing oil and natural gas leases was $1,862,455.

Oil and Natural Gas Sales Revenue Accrual

The Company does not operate any of its oil and natural gas properties. Drilling in the last two years has resulted in adding numerous wells with significantly larger working interests, thus increasing the Company s production subject to accrual. On many of these wells, the most current available production data is gathered from the appropriate operators and oil and natural gas index prices local to each well are used to more accurately estimate the accrual of revenue on these wells. Timely obtaining production data on all other wells from the operators is not feasible; therefore, the Company utilizes past production receipts and estimated sales price information to estimate its accrual of revenue on all other wells each quarter. The oil and natural gas sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil and natural gas. These variables could lead to an over or under accrual of oil and natural gas sales at the end of any particular quarter. Based on past history, the Company s estimated accrual has been materially accurate.

Income Taxes

The estimation of the amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations as well as the completion of complex calculations, including the determination of the Company s percentage depletion deduction, if any. To calculate the exact excess percentage depletion allowance, a well-by-well calculation is, and can only be, performed at the end of each fiscal year. During interim periods, a high-level estimate is made taking into account historical data and current pricing. The Company has certain state net operating loss carryforwards (NOLs) that are recognized as tax assets when assessed as more likely than not to be utilized before their expiration dates. Criteria such as expiration dates, future excess state depletion and reversing taxable temporary differences are evaluated to determine whether the NOLs are more likely than not to be utilized before they expire. If any NOLs are determined to no longer be more likely than not to be utilized, then a valuation allowance is recognized to reduce the tax benefit of such NOLs. Although the Company s management believes its tax accruals are adequate, differences may occur in the future depending on the resolution of pending and new tax matters.

Refundable Production Taxes Accrual

The state of Oklahoma allows for refunds of production taxes on wells that are horizontally drilled. In order to qualify as a horizontally drilled well, the well has completed in a manner which encounters and subsequently produces from a geological formation at an angle in excess of seventy (70) degrees from the vertical and which laterally penetrates a minimum of one hundred and fifty (150) feet into the pay zone of the formation . An operator has 18 months after a given tax year to file the appropriate forms with the Oklahoma Tax Commission (OTC) requesting the refund of production taxes. The refund is limited to 48 months from first sales or well payout, whichever comes first. Horizontal drilling in Oklahoma (mainly in the SE Woodford shale) over the past three years has resulted in the addition of numerous wells that qualify for the Oklahoma horizontal exemption, thus increasing the Company s oil and natural gas sales subject to the accrual.

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The Company does not operate any of its oil and natural gas properties and thus must rely on oil and natural gas sales as well as drilling information from the operators. The Company utilizes payment remittances from operators to estimate its refundable production tax accrual at the end of each quarterly period. The refundable production tax accrual can be impacted by many variables, including subsequent revenue adjustments received from operators and an operator s failure to file timely with the OTC requesting refunds. These variables could lead to an over or under accrual of production taxes at the end of any particular period. Based on historical experience, the estimated accrual has been materially accurate.

The above description of the Company s critical accounting policies is not intended to be an all-inclusive discussion of the uncertainties considered and estimates made by management in applying accounting principles and policies. Results may vary significantly if different policies were used or required and if new or different information becomes known to management.

ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company s results of operations and operating cash flows can be significantly impacted by changes in market prices for oil and natural gas. Based on the Company s 2009 production, a $.10 per Mcf change in the price received for natural gas production would result in a corresponding $911,000 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 $128,000 annual change in pre-tax operating cash flow. Cash flows could also be impacted, to a lesser extent, by changes in the market interest rates related to the Company s credit facilities. The revolving loan bears interest at the national prime rate plus from .50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%, with an established interest rate floor of 4.50% annually. At September 30, 2009, the Company had $10,384,722 outstanding under these facilities. A change of .5% in the prime rate or on LIBOR would result in a change to interest expense of $51,924.

The Company periodically utilizes derivative contracts to reduce its exposure to unfavorable changes in natural gas prices. Volumes under such contracts do not exceed expected production. These arrangements cover only a portion of the Company s production and provide only partial price protection against declines in natural gas prices. These derivative contracts may expose the Company to risk of financial loss and limit the benefit of future increases in prices (Refer to the Derivatives section of Note 1).

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Management s Annual Report on Internal Control Over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934 (the Exchange Act) as a process designed by, or under the supervision of, the Company s principal executive and principal financial officers and effected by the Company s board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Company;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

The Company s management assessed the effectiveness of the Company s internal control over financial reporting as of September 30, 2009. 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, 2009, the Company s internal control over financial reporting was effective based on those criteria.

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

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

We have audited Panhandle Oil and Gas Inc. s internal control over financial reporting as of September 30, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Panhandle Oil and Gas Inc. s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Panhandle Oil and Gas Inc. maintained, in all material respects, effective internal control over financial reporting as of September 30, 2009, based on the COSO criteria**.**

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Panhandle Oil and Gas Inc. as of September 30, 2009 and 2008, and the related consolidated statements of operations, stockholders   equity, and cash flows for each of the three years in the period ended September 30, 2009 and our report dated December 9, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Oklahoma City, Oklahoma
December 9, 2009

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Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Panhandle Oil and Gas Inc. (the Company) as of September 30, 2009 and 2008, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended September 30, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Panhandle Oil and Gas Inc. at September 30, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2009, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Panhandle Oil and Gas Inc. s internal control over financial reporting as of September 30, 2009, 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, 2009, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Oklahoma City, Oklahoma
December 9, 2009

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Panhandle Oil and Gas Inc.
Consolidated Balance Sheets

	September 30, 2009	September 30, 2008
Assets		
Current Assets:		
Cash and cash equivalents	$ 639,908	$ 895,708
Oil and natural gas sales receivables, net of allowance for uncollectible accounts	7,747,557	17,183,128
Deferred income taxes	1,934,900	
Refundable income taxes		2,162,305
Refundable production taxes	616,668	78,882
Short-term derivative contracts		646,193
Other	68,817	143,272
Total current assets	11,007,850	21,109,488
Properties and equipment at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	198,076,244	175,727,196
Non-producing oil and natural gas properties	10,332,537	11,216,103
Furniture and fixtures	578,460	491,321
	208,987,241	187,434,620
Less accumulated depreciation, depletion, and amortization	112,900,027	87,661,433
Net properties and equipment	96,087,214	99,773,187
Investments	682,391	736,314
Refundable production taxes	772,177	388,194
Total assets	$ 108,549,632	$ 122,007,183

(Continued on next page)

See accompanying notes.

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Panhandle Oil and Gas Inc.
Consolidated Balance Sheets

	September 30, 2009	September 30, 2008
Liabilities and Stockholders Equity		
Current Liabilities:		
Accounts payable	$ 4,810,687	$ 15,897,565
Short-term derivative contracts	1,726,901	
Accrued liabilities	1,033,570	608,456
Total current liabilities	7,571,158	16,506,021
Long-term debt	10,384,722	9,704,100
Deferred income taxes	24,064,650	25,943,750
Asset retirement obligations	1,620,225	1,504,411
Long-term derivative contracts	786,534	
Stockholders equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized, 8,431,502 issued at September 30, 2009 and September 30, 2008	140,524	140,524
Capital in excess of par value	1,922,053	2,090,070
Deferred directors compensation	1,862,499	1,605,811
Retained earnings	64,507,547	69,236,604
	68,432,623	73,073,009
Treasury stock, at cost; 119,866 shares at September 30, 2009 and 131,374 shares at September 30, 2008	(4,310,280)	(4,724,108)
Total stockholders equity	64,122,343	68,348,901
Total liabilities and stockholders equity	$ 108,549,632	$ 122,007,183

See accompanying notes.

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Panhandle Oil and Gas Inc.
Consolidated Statements of Operations

	Year ended September 30, 2009	2008	2007
Revenues:			
Oil and natural gas sales	$ 37,421,688	$ 69,026,785	$ 37,449,174
Lease bonuses and rentals	188,906	167,559	208,625
Gains (losses) on natural gas derivative contracts	(661,828)	(940,823)	765,316
Gain on sales of assets, interest and other	2,684,353	233,709	322,405
Income from partnerships	323,848	631,891	383,391
	39,956,967	69,119,121	39,128,911
Costs and expenses:			
Lease operating expenses and production taxes	8,897,235	10,055,762	6,057,456
Exploration costs	711,582	455,943	1,050,069
Depreciation, depletion, and amortization	28,168,933	19,784,660	15,291,625
Provision for impairment	2,464,520	526,380	3,761,832
Loss on sales of assets		204,189	254,395
General and administrative	4,866,044	5,006,512	3,877,492
Bad debt expense (recovery)	(185,272)	591,258	
Interest expense	6,946	44,346	133,578
	44,929,988	36,669,050	30,426,447
Income (loss) before provision (benefit) for income taxes	(4,973,021)	32,450,071	8,702,464
Provision (benefit) for income taxes	(2,568,000)	10,894,302	2,359,000
Net income (loss)	$ (2,405,021)	$ 21,555,769	$ 6,343,464
Basic earnings per common share:			
Net income (loss)	$ (0.29)	$ 2.54	$ 0.75

See accompanying notes.

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Panhandle Oil and Gas Inc.
Consolidated Statements of Stockholders Equity

	Class A voting Common Stock Shares	Class A voting Common Stock Amount	Capital in Excess of Par Value	Deferred Directors Compensation	Retained Earnings	Treasury Shares	Treasury Stock	Total
Balances at September 30, 2006	8,422,529	$ 140,375	$ 1,924,587	$ 1,202,569	$ 45,798,166		$	$ 49,065,697
Issuance of common shares to ESOP	8,973	149	221,484					221,633
Common shares to be issued to directors for services				156,209				156,209
Dividends declared ($.25 per share)					(2,105,632)			(2,105,632)
Net income					6,343,464			6,343,464
Balances at September 30, 2007	8,431,502	$ 140,524	$ 2,146,071	$ 1,358,778	$ 50,035,998		$	$ 53,681,371
Purchase of treasury stock						(139,014)	(4,998,842)	(4,998,842)
Issuance of common shares to ESOP			(56,001)			7,640	274,734	218,733
Common shares to be issued to directors for services				247,033				247,033
Dividends declared ($.28 per share)					(2,355,163)			(2,355,163)
Net income					21,555,769			21,555,769
Balances at September 30,	8,431,502	$ 140,524	$ 2,090,070	$ 1,605,811	$ 69,236,604	(131,374)	$ (4,724,108)	$ 68,348,901

2008								
Issuance of treasury shares to ESOP			(168,017)			11,508	413,828	245,811
Common shares to be issued to directors for services				256,688				256,688
Dividends declared ($.28 per share)					(2,324,036)			(2,324,036)
Net loss					(2,405,021)			(2,405,021)
Balances at September 30, 2009	8,431,502	$ 140,524	$ 1,922,053	$ 1,862,499	$ 64,507,547	(119,866)	$ (4,310,280)	$ 64,122,343

See accompanying notes.

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Panhandle Oil and Gas Inc.
Consolidated Statements of Cash Flows

	Year ended September 30, 2009	2008	2007
Operating Activities			
Net income (loss)	$ (2,405,021)	$ 21,555,769	$ 6,343,464
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization, and impairment	30,633,453	20,311,040	19,053,457
Deferred income taxes (net)	(3,814,000)	9,116,000	1,329,000
Exploration costs	711,582	455,943	1,050,069
Net (gain) loss on sales of assets	(2,654,759)	20,632	22,856
Income from partnerships	(323,848)	(631,891)	(383,391)
Distributions received from partnerships	373,063	585,588	465,535
Other	4,708		(45,954)
Common stock contributed to ESOP	245,811	218,733	221,633
Common stock (unissued) to Directors Deferred Compensation Plan	256,688	247,033	156,209
Bad debt expense (recovery)	(185,272)	591,258	
Cash provided (used) by changes in assets and liabilities:			
Oil and natural gas sales receivables	9,620,843	(9,671,136)	(1,631,627)
Fair value of dervative contracts	3,159,628	(539,277)	(106,916)
Refundable income taxes	2,162,305	(2,162,305)	1,772,987
Refundable production taxes	(537,786)	(78,882)	
Other current assets	74,455	(25,927)	3,767
Other non-current assets	(383,983)	(388,194)	(140,901)
Accounts payable	287,883	59,921	(118,012)
Income taxes payable	338,511	(211,155)	211,155
Accrued liabilities	86,603	471,569	(96,831)
Total adjustments	40,055,885	18,368,950	21,763,036
Net cash provided by operating activities	37,650,864	39,924,719	28,106,500
Investing Activities			
Capital expenditures, including dry hole costs	(39,915,051)	(38,747,749)	(27,785,431)
Proceeds from leasing of fee mineral acreage	209,930	200,356	188,417
Proceeds from sales of assets	3,441,871	840,398	656,335
Net cash used in investing activities	(36,263,250)	(37,706,995)	(26,940,679)

(Continued on next page)

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

	Year ended September 30, 2009	2008	2007
Financing Activities			
Borrowings under debt agreement	$ 49,027,225	$ 47,281,411	$ 18,046,213
Payments of loan principal	(48,346,603)	(42,238,782)	(16,551,395)
Purchases of treasury stock		(4,998,842)	
Payments of dividends	(2,324,036)	(2,355,163)	(2,105,632)
Net cash used in financing activities	(1,643,414)	(2,311,376)	(610,814)
Increase (decrease) in cash and cash equivalents	(255,800)	(93,652)	555,007
Cash and cash equivalents at beginning of year	895,708	989,360	434,353
Cash and cash equivalents at end of year	$ 639,908	$ 895,708	$ 989,360
Supplemental Disclosures of Cash Flow Information			
Interest paid (net of capitalized interest)	$	$ 23,212	$ 140,350
Income taxes paid, net of refunds received	$ (1,261,808)	$ 4,145,122	$ (952,221)
Supplemental schedule of noncash investing and financing activities:			
Additions and revisions, net, to asset retirement obligations	$ 95,076	$ 151,998	$ (213,759)
Gross additions to properties and equipment	$ 28,540,290	$ 52,812,138	$ 28,112,522
Net (increase) decrease in accounts payable for properties and equipment additions	11,374,761	(14,064,389)	(327,091)
Capital expenditures, including dry hole costs	$ 39,915,051	$ 38,747,749	$ 27,785,431

See accompanying notes.

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements
September 30, 2009, 2008 and 2007

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Since its formation, the Company has been involved in the acquisition and management of fee mineral acreage and the exploration for, and development of, oil and natural gas properties, principally involving drilling wells located on the Company s mineral acreage. Panhandle s mineral properties and other oil and natural gas interests are all located in the United States, primarily in Arkansas, Kansas, Oklahoma, New Mexico and Texas. The Company is not the operator of any wells. The majority of the Company s oil and natural gas production is from interests in 4,861 wells located principally in Oklahoma. Approximately 82% of oil and natural gas revenues are derived from the sale of natural gas. Substantially all the Company s oil and natural gas production is sold through the operators of the wells. The Company from time to time disposes of certain non-material, non-core or small interest oil and natural gas properties as a normal course of business.

Principles of Consolidation and Basis of Presentation

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

Certain assets (refundable production taxes) in the prior year have been reclassified to conform to the current year presentation.

Use of Estimates

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts and disclosures reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Of these estimates and assumptions, 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 depreciation, depletion and amortization (DD&A) and impairment calculations. On an annual basis, with a limited scope semi-annual update, the Company s Consulting Petroleum Engineer, with assistance from the Company 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. For DD&A purposes, and as required by the guidelines and definitions established by the SEC (prior to those expected to become effective for fiscal years ending on or after December 31, 2009), these estimates are based on year-end crude oil and natural gas pricing. For impairment purposes, projected future crude oil and natural gas prices as estimated by management are used. 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.

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in short-term investments with original maturities of three months or less.

Oil and Natural Gas Sales and Natural Gas Imbalances

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

The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has underproduced or overproduced its ownership percentage in a property. Under this method, a receivable or liability is recorded to the extent that an underproduced or overproduced position in a reservoir cannot be recouped through the production of remaining reserves. At September 30, 2009 and 2008, the Company had no material natural gas imbalances.

Concentration of Credit Risk

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

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

Derivative contracts entered into by the Company are also unsecured.

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Oil and Natural Gas Producing Activities

The Company follows the successful efforts method of accounting for oil and natural gas producing activities. Intangible drilling and other costs of successful wells and development dry holes are capitalized and amortized. The costs of exploratory wells are initially capitalized, but charged against income if and when the well is determined to be nonproductive. Oil and natural gas mineral and leasehold costs are capitalized when incurred.

Non-producing oil and natural gas leases are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties costs which the Company believes will not be transferred to proved properties over the remaining lives of the leases. Impairment loss is charged to exploration costs when recognized. As of September 30, 2009, the remaining carrying cost of non-producing oil and natural gas leases was $1,862,455.

It is common business practice in the petroleum industry for drilling costs to be prepaid before spudding a well. The Company frequently fulfills these prepayment requirements with cash payments, but at times will utilize letters of credit to meet these obligations. As of September 30, 2009, the Company had outstanding letters of credit totaling $313,125 that expire in March 2010. In October 2009, the Company added letters of credit for $533,406 that expire in January 2010 and May 2010.

Derivatives

In the past, the Company entered into costless collar contracts (all of which expired in the 2009 first quarter). Currently, the Company has entered into fixed swap contracts. Both of these instruments were intended to reduce the Company s exposure to short-term fluctuations in the price of natural gas. Collar contracts set a fixed floor price and a fixed ceiling price and provide payments to the Company if the index price falls below the floor or require payments by the Company if the index price rises above the ceiling. Fixed swap contracts set a fixed price and provide payments to the Company if the index price is below the fixed price, or require payments by the Company if the index price is above the fixed price. These contracts cover only a portion of the Company s natural gas production and provide only partial price protection against declines in natural gas prices. These derivative instruments may expose the Company to risk of financial loss and limit the benefit of future increases in prices. All of the Company s derivative contracts are with Bank of Oklahoma and are unsecured. The derivative instruments have settled or will settle based on the prices below which are adjusted for location differentials and tied to certain pipelines in Oklahoma.

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Derivative contracts in place during 2009
(prices below reflect the Company s net price from the listed Oklahoma pipelines)

Contract period	Production volume covered per month	Indexed (1) Pipeline	Fixed price
March December, 2009	60,000 Mmbtu	CEGT	$4.01
April December, 2009	100,000 Mmbtu	CEGT	$3.71
May December, 2009	70,000 Mmbtu	CEGT	$3.615
July December, 2009	70,000 Mmbtu	PEPL	$3.745
January December, 2010	100,000 Mmbtu	CEGT	$5.015
January December, 2010	50,000 Mmbtu	CEGT	$5.050
January December, 2010	100,000 Mmbtu	PEPL	$5.57
January December, 2010	50,000 Mmbtu	PEPL	$5.56

(1) CEGT Centerpoint Energy Gas Transmission s East pipeline in Oklahoma

PEPL Panhandle Eastern Pipeline Company s Texas/Oklahoma mainline

While the Company believes that its derivative contracts are effective in achieving the risk management objective for which they were intended, the Company has elected not to complete all of the documentation requirements necessary to permit these derivative contracts to be accounted for as cash flow hedges. The Company s fair value of derivative contracts was a liability of $2,513,435 as of September 30, 2009 and a receivable of $646,193 as of September 30, 2008. Realized and unrealized gains and (losses) are scheduled below:

Gains (losses) on natural gas derivative contracts short-term	Fiscal year ended 9/30/2009	Fiscal year ended 9/30/2008
Realized	$ 2,497,800	$ (1,480,100)
Increase (decrease) in fair value	(2,373,094)	539,277
Total	$ 124,706	$ (940,823)

Gains (losses) on natural gas derivative contracts long-term	Fiscal year ended 9/30/2009	Fiscal year ended 9/30/2008
Realized	$	$
Decrease in fair value	(786,534)	
Total	$ (786,534)	$

Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

To the extent that a legal offset exists, the Company nets the fair value of its derivative contracts with the same counterparty in the accompanying balance sheets. The following table summarizes the Company s derivative contracts as of September 30, 2009 and September 30, 2008:

	Balance Sheet Location	9/30/2009 Fair Value	9/30/2008 Fair Value
Asset Derivatives:			
Derivatives not designated as Hedging Instruments:			
Commodity contracts	Short-term derivative contracts	$	$ 654,195
Commodity contracts	Long-term derivative contracts		
Total Asset Derivatives (a)		$	$ 654,195
Liability Derivatives:			
Derivatives not designated as Hedging Instruments:			
Commodity contracts	Short-term derivative contracts	$ 1,726,901	$ 8,002
Commodity contracts	Long-term derivative contracts	786,534	
Total Liability Derivatives (a)		$ 2,513,435	$ 8,002

(a) See Fair Value Measurements section for further disclosures regarding fair value of financial instruments.

The fair value of derivative assets and derivative liabilities is adjusted for credit risk only if the impact is deemed material. The impact of credit risk was immaterial for all periods presented.

Fair Value Measurements

Effective October 1, 2008, the Company adopted fair value measurements for its financial assets and liabilities measured on a recurring basis. This guidance establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB delayed the effective date by one year for nonfinancial assets and liabilities. The Company has only applied the fair value measurement statement to financial assets and liabilities and will delay application for nonfinancial assets and liabilities (including, but not limited to, its asset retirement obligations) until the Company s fiscal year beginning October 1, 2009 as permitted. The Company is currently assessing the impact that full application for nonfinancial assets and liabilities will have on its financial position, results of operations and cash flows.

This guidance defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs include the following: (i) quoted prices for similar assets or liabilities in

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active; (iii) inputs other than quoted prices that are observable for the asset or liability; or (iv) inputs that are derived principally from or corroborated by observable market data by correlation or other means. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Counterparty quotes are generally assessed as a Level 3 input.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2009.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative Contracts Swaps		$ (2,513,435)		$ (2,513,435)

Level 2 Fair Value Measurements

Derivatives. The fair values of the Company s natural gas swaps are corroborated by observable market data by correlation to Nymex natural gas forward curve pricing. These values are based upon, among other things, future prices and time to maturity.

Level 3 Fair Value Measurements

Derivatives. The fair values of the Company s derivatives, excluding natural gas swaps, are based on estimates provided by its respective counterparty and reviewed internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility and time to maturity.

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

	Derivatives
Balance of Level 3 as of October 1, 2008	$ 646,193
Total gains or losses (realized/unrealized):	
Included in earnings	393,007
Included in other comprehensive income (loss)	
Purchases, issuances and settlements	(1,039,200)
Transfers in and out of Level 3	
Balance of Level 3 as of September 30, 2009	$

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

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

Depreciation, Depletion, Amortization, and Impairment

Depreciation, depletion, and amortization of the costs of producing oil and natural gas properties are generally computed using the units of production method primarily on a separate property basis using proved or proved developed reserves, as applicable, as estimated by the Company s Consulting Petroleum Engineer. Depreciation of furniture and fixtures is computed using the straight-line method over estimated productive lives of five to eight years.

Non-producing oil and natural gas properties include non-producing minerals, which have a net book value of $4,771,926 at September 30, 2009, consisting of perpetual ownership of mineral interests in several states, with 81% of the acreage in Arkansas, New Mexico, Oklahoma and Texas. As mentioned these mineral rights are perpetual and have been accumulated over the 83 year life of the Company. There are approximately 206,000 net acres of non-producing minerals in over 7,000 tracts owned by the Company. An average tract contains approximately 29 acres and the average cost per acre is $39. Since inception, the Company has continually generated an interest in several thousand oil and natural gas wells using its ownership of the fee mineral acres as an ownership basis. There continues to be significant drilling activity each year on these mineral interests. Non-producing minerals are being amortized straight-line over a thirty-three year period. These assets are considered a long-term investment by the Company as they do not expire (as do oil and natural gas leases). Given the above, it was concluded that a longer term amortization was appropriate and that 33 years, based on past history and experience was an appropriate period. Due to the fact that the minerals consist of a large number of properties whose costs are not individually significant, and because virtually all are in the Company s core operating areas, the minerals are being amortized on an aggregate basis.

The Company recognizes impairment losses for long-lived assets when indicators of impairment are present and the undiscounted cash flows are not sufficient to recover the assets carrying amount. The impairment loss is measured by comparing the fair value of the asset to its carrying amount. Fair values are based on discounted cash flow techniques considering oil and natural gas quantities as estimated by the Company s Consulting Petroleum Engineer, prices and costs. The Company s estimate of fair value of its oil and natural gas properties at September 30, 2009 is based on the best information available as of that date, including estimates of forward oil and natural gas prices. The Company s oil and natural gas properties were reviewed for impairment on a field-by-field basis, resulting in the recognition of impairment provisions of $2,464,520, $526,380 and $3,761,832 respectively, for 2009, 2008 and 2007. A future reduction in oil and natural gas prices or a decline in reserve volumes would likely lead to additional impairment in future periods that may be material to the Company.

Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Capitalized Interest

During 2009, 2008 and 2007, interest of $455,516, $144,520 and $0, respectively, was included in the Company s capital expenditures. Interest of $6,946, $44,346 and $133,578, respectively, was charged to expense during those periods. Interest is capitalized using a weighted average interest rate based on the Company s outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using units of production method.

Investments

Insignificant investments in partnerships and limited liability companies (LLC) that maintain specific ownership accounts for each investor and where the Company holds an interest of five percent or greater, but does not have control of the partnership or LLC, are accounted for using the equity method of accounting.

Asset Retirement Obligations

The Company owns interests in oil and natural gas properties which may require expenditures to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. These obligations are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). The obligations represent the Company s share of the total costs of all wells. The Company does not have any assets restricted for the purpose of settling the plugging liabilities.

The following table shows the activity for the year ended September 30, 2009 relating to the Company s retirement obligation for plugging liability:

	Plugging Liability
Plugging Liability as of September 30, 2008	$ 1,504,411
Accretion of Discount	104,991
New Wells Placed on Production	118,371
Wells Sold or Plugged	(107,548)
Plugging Liability as of September 30, 2009	$ 1,620,225

Environmental Costs

As the Company is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local provisions regarding environmental and ecological matters. Compliance with these laws may necessitate significant capital outlays; however, to date the Company s cost of compliance has been insignificant. The Company does not believe the existence of current environmental laws or interpretations thereof will materially hinder or adversely affect the Company s business operations; however, there can be no assurances of future effects on the Company of new laws or interpretations thereof. Since the Company does not operate any wells where it owns an interest, actual compliance with environmental laws is controlled by others, with Panhandle being responsible for its proportionate share of the costs involved. Panhandle carries liability insurance and to the extent available at reasonable cost, pollution control coverage. However, all risks are not insured due to the

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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, 2009 and 2008, there were no such costs accrued.

Earnings Per Share of Common Stock

Earnings per share is calculated using net income divided by the weighted average of common shares outstanding including unissued, vested directors shares during the period.

Share-based Compensation

The Company recognizes current compensation costs for its Deferred Compensation Plan for Non-Employee Directors (the Plan). Compensation cost is recognized for the requisite directors fees as earned and unissued stock is added to each director s account based on the fair market value of the stock at the date earned. The Plan s structure is, that upon retirement, termination or death of the director or upon a change in control of the Company, the shares accrued under the Plan will be issued to the director.

In accordance with guidance on accounting for employee stock ownership plans, the Company records as expense, the fair market value of the stock at the time of contribution into its ESOP.

Income Taxes

The estimation of amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations as well as the completion of complex calculations, including the determination of the Company s percentage depletion deduction. Although the Company s management believes its tax accruals are adequate, differences may occur in the future depending on the resolution of pending and new tax matters. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of the Company s assets and liabilities.

On October 1, 2007, the Company adopted the guidelines on accounting for income tax uncertainties; the impact was not material. The guidelines prescribe a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Company and its subsidiary file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Subject to statutory exceptions that allow for a possible extension of the assessment period, the Company is no longer subject to U.S. federal, state, and local income tax examinations for fiscal years prior to 2006.

The Company includes interest assessed by the taxing authorities in Interest expense and penalties related to income taxes in General and administrative expense on its Consolidated Statements of Income. For fiscal September 30, 2009, 2008 and 2007, the Company recorded no interest or penalties as the Company does not believe it has any significant uncertain tax positions.

Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

New Accounting Standards

In June 2009, the FASB approved the FASB Accounting Standards Codification (ASC), which, as of July 1, 2009, became the single source of authoritative, nongovernmental U.S. Generally Accepted Accounting Principles (GAAP). The ASC was not intended to change U.S. GAAP. Rather, the ASC reorganizes all previous U.S. GAAP pronouncements into accounting topics, and displays all topics using a consistent structure. All existing standards that were used to create the ASC are now superseded, aside from those issued by the SEC, replacing the previous references to specific Statements of Financial Accounting Standards with numbers used in the ASC s structural organization. All guidance in the Codification has an equal level of authority. The ASC is effective for financial statements that cover interim and annual periods ending after September 15, 2009. There was no impact on the Company s financial position, results of operations or cash flows as a result of the Accounting Standards Codification.

In February 2007, the FASB issued The Fair Value Option for Financial Assets and Financial Liabilities. This guidance permits entities to choose to measure many financial instruments and certain other items at fair value. This guidance was effective for financial statements issued for fiscal years beginning after November 15, 2007. Since the Company has not elected to adopt the fair value option for eligible items, there has been no impact to its financial position, results of operations or cash flows.

In December 2008, the SEC issued revised reporting requirements for oil and natural gas reserves that a company holds. Included in the new rule entitled *Modernization of Oil and Gas Reporting Requirements,* are the following changes: 1) permitting use of new technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; 2) enabling companies to additionally disclose their probable and possible reserves to investors, in addition to their proved reserves; 3) allowing previously excluded resources, such as oil sands, to be classified as oil and natural gas reserves rather than mining reserves; 4) requiring companies to report the independence and qualifications of a preparer or auditor, based on current Society of Petroleum Engineers criteria; 5) requiring the filing of reports for companies that rely on a third party to prepare reserve estimates or conduct a reserve audit; and 6) requiring companies to report oil and natural gas reserves using an average price based upon the prior 12-month period, rather than year-end prices. The new requirements are effective for registration statements filed on or after January 1, 2010, and for annual reports on Form 10K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. The Company is currently assessing the impact that adoption of this rule will have on its financial disclosures.

In September 2009, the FASB issued an exposure draft of proposed Accounting Standards Update (ASU) entitled *Oil and Gas Reserve Estimation and Disclosures.* This proposed ASU would amend the FASB accounting standards to align the reserve calculation and disclosure requirements with the requirements in the new SEC Rule, *Modernization of Oil and Gas Reporting Requirements*. As proposed, the ASU would be effective for reporting periods ending on or after December 31, 2009.

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

On June 30, 2009, the Company adopted accounting guidance which requires disclosures about fair value of financial instruments in interim financial statements as well as in annual financial statements. The adoption of this accounting guidance required additional disclosures regarding the Company s financial instruments; however, it did not have a material impact on the Company s financial condition or results of operations.

In May 2009, the FASB issued guidance which sets forth general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued, or are available to be issued. The guidance sets forth the following: 1) The period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; 2) The circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; 3) The disclosures that an entity should make about events or transactions that occurred after the balance sheet date. This guidance is effective for interim and annual financial periods ending after June 15, 2009. Effective June 30, 2009 the Company adopted this guidance, and the adoption did not result in significant changes in the subsequent events that the Company reports, either through recognition or disclosure, in its financial statements.

Other accounting standards that have been issued or proposed by the FASB, or other standards-setting bodies, that do not require adoption until a future date are not expected to have a material impact on the consolidated financial statements upon adoption.

2. COMMITMENTS

The Company leases office space in Oklahoma City, Oklahoma under the terms of an operating lease expiring in April 2012. Future minimum rental payments under the terms of the lease are $204,089 in 2010, $204,089 in 2011 and $119,052 in 2012. Total rent expense incurred by the Company was $200,627 in 2009, $175,335 in 2008 and $147,849 in 2007.

3. INCOME TAXES

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

	2009	2008	2007
Current:			
Federal	$ 1,246,000	$ 1,728,000	$ 1,000,000
State		50,302	30,000
	1,246,000	1,778,302	1,030,000
Deferred:			
Federal	(3,254,000)	8,090,000	1,083,000
State	(560,000)	1,026,000	246,000
	(3,814,000)	9,116,000	1,329,000
	$ (2,568,000)	$ 10,894,302	$ 2,359,000

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

3. INCOME TAXES (CONTINUED)

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

	2009	2008	2007
Provision (benefit) for income taxes at statutory rate	$(1,690,827)	$11,336,596	$2,958,838
Percentage depletion	(469,962)	(1,072,282)	(604,662)
State income taxes, net of federal provision (benefit)	(451,440)	797,550	272,580
State net operating loss valuation allowance (carryforward)	124,000	(143,000)	(102,925)
Other	(79,771)	(24,562)	(164,831)
	$(2,568,000)	$10,894,302	$2,359,000

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:

	2009	2008
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$27,139,652	$29,236,442
Deferred tax assets:		
Alternative minimum tax credit carryforwards	2,207,810	1,532,770
State net operating loss carry forwards, net of valuation allowance of $278,000 in 2009	926,600	915,032
Derivative contracts	977,726	
Deferred directors compensation, allowance for uncollectible accounts and other	897,766	844,890
	5,009,902	3,292,692
Net deferred tax liabilities	$22,129,750	$25,943,750

At September 30, 2009, the Company had an income tax benefit of $1,204,600 related to Oklahoma state income tax net operating loss (OK NOL) carryforwards, of which the Company has recognized a valuation allowance of $278,000 for OK NOL carryforwards expiring in fiscal years 2013 through 2016, for which years the Company no longer believes it is more likely than not that the OK NOL s will be utilized. The remaining $926,600 income tax benefit is for OK NOL carryforwords expiring from 2022 to 2029.

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

4. LONG-TERM DEBT

The Company has a credit facility with Bank of Oklahoma (BOK) which consists of a revolving loan in the amount of $50,000,000 which is subject to a semi-annual borrowing base determination, wherein BOK applies their own current pricing forecast and a 9% discount rate to the Company s proved reserves as calculated by the Company s Consulting Petroleum Engineering Firm. When applying the discount rate, BOK also applies an advance rate percentage to risk all proved non-producing and proved undeveloped reserves. Effective February 3, 2009, the Company amended its revolving credit facility with BOK to increase the borrowing base from $15,000,000 to $25,000,000 (the revolving loan amount remains $50,000,000), restructure the interest rate, secure the loan by certain of the Company s properties and change the maturity date to October 31, 2011. Effective May 20, 2009 the Company again increased the borrowing base from $25,000,000 to $35,000,000. The restructured interest rate is based on national prime plus from .50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%, with an established interest rate floor of 4.50% annually. The 4.50% interest rate floor was in effect at September 30, 2009. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the loan value of the Company s oil and natural gas properties is advanced. If the interest rate calculation utilizing the national prime or LIBOR rate exceeds the interest rate floor, the interest rate spread from national prime or LIBOR will be charged based on the percent of the value advanced of the calculated loan value of the Company s oil and natural gas properties. Borrowings outstanding under the revolving loan amounted to $10,384,722 and $9,704,100 as of September 30, 2009 and 2008, respectively.

Determinations of the borrowing base are made semi-annually or whenever the bank, in its sole discretion, believes that there has been a material change in the value of the oil and natural gas properties. The 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, 2009, the Company was in compliance with the covenants of the BOK agreement.

5. SHAREHOLDERS EQUITY

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

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

On May 28, 2008 and July 29, 2008 the Company announced that its Board of Directors had approved stock repurchase programs to purchase up to $2,000,000 and $3,000,000 (respectively) of the Company s common stock. These programs were completed in 2008. The shares are held in treasury and are accounted for using the cost method. At September 30, 2009 and September 30, 2008, 11,508

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

5. SHAREHOLDERS EQUITY (CONTINUED)

and 7,640 (respectively) treasury shares were contributed to the Company s ESOP on behalf of the ESOP participants.

6. EARNINGS PER SHARE

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

	Year ended September 30,		
	2009	2008	2007
Numerator for earnings per share:			
Net income (loss)	$(2,405,021)	$21,555,769	$6,343,464
Denominator for earnings per share weighted average shares (including for 2009, 2008 and 2007, unissued, vested directors shares of 97,177, 85,504 and 76,679, respectively)	8,397,337	8,492,378	8,499,233

7. EMPLOYEE STOCK OWNERSHIP PLAN

The Company s ESOP was established in 1984 and is a tax qualified, defined contribution plan, and serves as the Company s sole retirement plan for its employees. Company contributions are made at the discretion of the Board of Directors and, to date, all contributions have been made in shares of Company common stock. The Company contributions are allocated to all ESOP participants in proportion to their salaries for the plan year and 100% vesting occurs after three years of service. For contributions of common stock, the Company records as expense, the fair market value of the stock at the time of contribution. The 241,251 shares of the Company s common stock held by the plan as of September 30, 2009, 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
2009	11,508	$ 245,811
2008	7,640	$ 218,733
2007	8,973	$ 221,781

8. DEFERRED COMPENSATION PLAN FOR DIRECTORS

Effective November 1, 1994, the Company formed the Panhandle Oil and Gas Inc. 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. As of September 30, 2009, there were 99,560 shares (86,853 shares at September 30, 2008) included in the Plan. The deferred balance outstanding at September 30, 2009 under the Plan was $1,862,499 ($1,605,811 at September 30, 2008). $256,688, $247,033 and $156,209

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

8. DEFERRED COMPENSATION PLAN FOR DIRECTORS (CONTINUED)

were charged to the Company s results of operations for the years ended September 30, 2009, 2008 and 2007, respectively, and are included in general and administrative expense in the accompanying income statement.

9. INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES

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

During 2009, 2008 and 2007 approximately 20%, 16% and 20%, respectively, of the Company s total revenues were derived from sales through Chesapeake Operating, Inc. During 2009, 2008 and 2007 approximately 14%, 17% and 13%, respectively, of the Company s total revenues were derived from sales through JMA Energy Company. During 2009 and 2008 approximately 17% and 12% of the Company s total revenues were derived from sales through Newfield Exploration.

Aggregate Capitalized Costs

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

	2009	2008
Producing properties	$ 198,076,244	$175,727,196
Non-producing minerals	8,036,236	8,097,518
Non-producing leasehold	2,241,232	2,369,748
Exploratory wells in progress	55,069	748,837
	208,408,781	186,943,299
Accumulated depreciation, depletion and amortization	(112,505,428)	(87,329,312)
Net capitalized costs	$ 95,903,353	$ 99,613,987

Costs Incurred

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

	2009	2008	2007
Property acquisition costs	$ 382,239	$ 2,359,988	$ 1,592,441
Exploration costs	1,647,456	1,887,182	4,604,380
Development costs	26,411,704	48,503,130	21,906,032
	$28,441,399	$52,750,300	$28,102,853

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

10. SUPPLEMENTARY INFORMATION ON OIL AND NATURAL 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 the FASB.

Proved developed reserves are those quantities of petroleum from existing wells and facilities, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations. Proved undeveloped reserves are those quantities of petroleum expected to be recovered through future investment within a reasonable timeframe in a drilling unit immediately adjacent to the drilling unit containing a producing well, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations.

The Company s net proved (including certain undeveloped reserves described above) oil and natural gas reserves, all of which are located in the United States, as of September 30, 2009, 2008 and 2007, have been estimated by the Company s 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, 2009, 2008 and 2007. 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.

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

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

Estimated Quantities of Proved Oil and Natural Gas Reserves

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

	Proved Reserves	
	Oil (Mbarrels)	Natural Gas (MMcf)
September 30, 2006	575	30,869
Revisions of previous estimates	219	50
Divestitures	(2)	(162)
Extensions and discoveries	138	11,396
Production	(107)	(5,147)
September 30, 2007	823	37,006
Revisions of previous estimates	136	117
Divestitures	(1)	(83)
Extensions and discoveries	164	18,039
Production	(132)	(6,928)
September 30, 2008	990	48,151
Revisions of previous estimates	(30)	589
Divestitures	(4)	(317)
Extensions and discoveries	93	14,715
Production	(128)	(9,110)
September 30, 2009	921	54,028

The prices used to calculate reserves and future cash flows from reserves for oil and natural gas, respectively, were as follows: September 30, 2009 $66.96/Bbl, $2.86/Mcf; September 30, 2008 - $97.74/Bbl, $4.51/Mcf; September 30, 2007 $78.93/Bbl, $5.50/Mcf (these natural gas prices are representative of local pipelines in Oklahoma).

The revisions of previous estimates were primarily the result of 1) negative oil and natural gas pricing revisions, 77,949 Bbls of oil and 5,918 Mmcf of natural gas, and 2) positive performance revisions which were principally attributable to properties in the Southeastern Oklahoma Woodford Shale and Arkansas Fayetteville Shale, 47,683 Bbls of oil and 6,507 Mmcf of natural gas.

The Company divested certain interests in the Southeast Leedey field in Oklahoma and the McElmo Dome Unit in Colorado.

Extensions and discoveries are principally attributable to the Company s continued growth strategy, adopted in mid 2006, of significantly increasing drilling expenditures in unconventional natural

Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

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

gas plays (shale gas), including the Southeastern Oklahoma Woodford Shale and Arkansas Fayetteville Shale and to a lesser extent conventional drilling in Western Oklahoma.

	Proved Developed Reserves		**Proved Undeveloped Reserves**	
	Oil (Mbarrels)	**Natural Gas (MMcf)**	**Oil (Mbarrels)**	**Natural Gas (MMcf)**
September 30, 2007	755	31,016	68	5,990
September 30, 2008	895	35,970	95	12,181
September 30, 2009	883	45,036	38	8,991

The above reserve numbers exclude approximately 2.9 and 2.3 Bcf of CO_2 gas reserves for the years ended September 30, 2008 and 2007, respectively. These reserves were sold in the fourth quarter of 2009.

Standardized Measure of Discounted Future Net Cash Flows

Estimates of future cash flows from proved oil and natural 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.

	2009	**2008**	**2007**
Future cash inflows	$216,181,210	$318,004,410	$270,149,990
Future production costs	62,102,230	79,668,500	61,736,120
Future development costs	5,412,470	19,364,580	9,429,990
Asset retirement obligation	1,620,225	1,504,411	1,247,908
Future income tax expense	43,832,666	68,086,237	61,164,668
Future net cash flows	103,213,619	149,380,682	136,571,304
10% annual discount	49,467,111	70,585,957	59,542,180
Standardized measure of discounted future net cash flows	$ 53,746,508	$ 78,794,725	$ 77,029,124

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Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

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

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

	2009	2008	2007
Beginning of year	$ 78,794,725	$ 77,029,122	$ 51,191,567
Changes resulting from:			
Sales of oil and natural gas, net of production costs	(28,524,453)	(58,971,023)	(31,391,718)
Net change in sales prices and production costs	(59,790,799)	9,274,593	43,499,178
Net change in future development costs	7,769,930	(5,841,539)	(1,511,175)
Net change in asset retirement obligation	(63,536)	(142,847)	74,315
Extensions and discoveries	21,677,448	46,677,163	35,711,533
Revisions of quantity estimates	587,215	2,417,457	4,401,619
Divestitures of reserves-in-place	(480,535)	(208,419)	(516,909)
Accretion of discount	12,110,733	11,626,875	6,772,402
Net change in income taxes	15,389,517	(3,072,975)	(22,707,174)
Change in timing and other, net	6,276,263	6,318	(8,494,516)
Net change	(25,048,217)	1,765,603	25,837,555
End of year	$ 53,746,508	$ 78,794,725	$ 77,029,122

11. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

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

	Fiscal 2009 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 11,319,702	$ 8,874,015	$ 8,779,960	$ 10,983,290
Income (loss) before provision for income taxes	(1,053,629)	(1,971,256)	(2,001,512)	53,376
Net income (loss)	(874,629)	(945,256)	(928,512)	343,376
Earnings (loss) per share	$ (0.10)	$ (0.11)	$ (0.11)	$ 0.04

	Fiscal 2008 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 13,703,803	$ 12,747,222	$ 18,453,206	$ 24,214,890
Income before provision for income taxes	5,299,307	4,311,281	9,486,885	13,352,598
Net income	3,480,307	2,831,281	6,468,885	8,775,296
Earnings per share	$ 0.41	$ 0.33	$ 0.76	$ 1.04

(60)

Panhandle Oil and Gas Inc.
Notes to Consolidated Financial Statements (continued)

11. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED) (CONTINUED)

During the fourth quarter of 2009, the Company sold a portion of its interest in the Southeast Leedey Field in Oklahoma and all of its interest in the McElmo Dome Unit in Colorado, the Company s sole source of CO_2 production. The total proceeds from the 2009 sale of these two properties were approximately $3.4 million; the combined gain on sale of assets recorded for these two properties was approximately $2.5 million.

12. SUBSEQUENT EVENTS

Subsequent events have been evaluated through December 9, 2009. This was the same date that the financial statements were filed with the SEC.

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

NONE

ITEM 9A CONTROLS AND PROCEDURES

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Company maintains disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including the Company s President/CEO and Vice President/CFO, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. The Company s disclosure controls and procedures have been designed to meet, and management believes that they do meet, reasonable assurance standards. Based on their evaluation as of the end of the fiscal period covered by this report, the President/CEO and Vice President/CFO have concluded that, subject to the limitations noted above, the Company s disclosure controls and procedures were effective.

(b) MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company s management is responsible for establishing and maintaining adequate internal control over financial reporting , as such term is defined in Exchange Act Rule 13a-15(f). The Company s management, including the President/CEO and Vice President/CFO, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the Company s management concluded that its internal control over financial reporting was effective as of September 30, 2009.

(c) CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in the Company s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting made during the fiscal quarter ended September 30, 2009 or subsequent to the date the assessment was completed.

ITEM 9B OTHER INFORMATION

None

PART III

The information called for by Part III of Form 10-K (Item 10 Directors and Executive Officers of the Registrant, Item 11 Executive Compensation, Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 13 Certain Relationships and Related Transactions, and Item 14 Principal Accountant Fees and Services), is incorporated by reference from the Company s definitive proxy statement, which will be filed with the SEC within 120 days after the end of the fiscal year to which this report relates.

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PART IV

ITEM 15 EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

FINANCIAL STATEMENT SCHEDULES

The Company has omitted all other schedules because the conditions requiring their filing do not exist or because the required information appears in the Company s Consolidated Financial Statements, including the notes to those statements.

EXHIBITS

(3)	Amended Certificate of Incorporation (incorporated by reference to Exhibit attached to Form 10 filed January 27, 1980, and to Forms 8-K dated June 1, 1982, December 3, 1982, to Form 10-QSB dated March 31, 1999 and to Form 10-Q dated March 31, 2007). By-Laws as amended (incorporated by reference to Form 8-K dated October 31, 1994 By-Laws as amended (incorporated by reference to Form 8-K dated February 24, 2006) By-Laws as amended (incorporated by reference to Form 8-K dated October 29, 2008)
(4)	Instruments defining the rights of security holders (incorporated by reference to Certificate of Incorporation and By-Laws listed above)
*(10)	Agreement indemnifying directors and officers (incorporated by reference to Form 10-K dated September 30, 1989 and Form 8-K dated June 15, 2007)
*(10)	Agreements to provide certain severance payments and benefits to executive officers should a Change-in-Control occur as defined by the agreements (incorporated by reference to Form 8-K dated September 4, 2007)
(21)	Subsidiaries of the Registrant
(23)	Consent of Independent Petroleum Engineers
(31.1)	Certification of Chief Executive Officer
(31.2)	Certification of Chief Financial Officer
(32.1)	Certification of Chief Executive Officer
(32.2)	Certification of Chief Financial Officer
(99)	Credit Agreement dated October 31, 2006 and amendment dated February 3, 2009 (incorporated by reference to Form 10-Q dated June 30, 2009)
(99)	Amendment to Credit Agreement dated December 8, 2009

* Indicates management contract or compensatory plan or arrangement

REPORTS ON FORM 8-K

No Form 8-K s were filed in the fourth quarter of 2009.

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SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

PANHANDLE OIL AND GAS INC.

By: /s/ Michael C. Coffman

Michael C. Coffman
President;
Chief Executive Officer

Date: December 9, 2009

By: /s/ Lonnie J. Lowry

Lonnie J. Lowry
Vice President;
Chief Financial Officer

Date: December 9, 2009

By: /s/ Robb P. Winfield

Robb P. Winfield
Controller;
Chief Accounting Officer

Date: December 9, 2009

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

/s/ Bruce M. Bell

Bruce M. Bell, Director

Date December 9, 2009

/s/ E. Chris Kauffman

E. Chris Kauffman, Director

Date December 9, 2009

/s/ Duke R. Ligon

Duke R. Ligon, Director

Date December 9, 2009

/s/ Robert O. Lorenz

Robert O. Lorenz, Lead Independent Director

Date December 9, 2009

/s/ Robert A. Reece

Robert A. Reece, Director

Date December 9, 2009

/s/ Robert E. Robotti

Robert E. Robotti, Director

Date December 9, 2009

/s/ H. Grant Swartzwelder

H. Grant Swartzwelder, Director

Date December 9, 2009