ARENA RESOURCES INC
Form 10KSB/A
October 17, 2005

United States Securities and Exchange Commission

Washington, D.C. 20549

Form 10-KSB/A

Amendment No. 1

(Mark One)
|X| Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2004
Or
|__| Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ___________to ___________

Commission file number 001-31657

Arena Resources, Inc.

(Name of small business issuer in its charter)

Nevada	**73-1596109**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
4920 South Lewis Avenue, Suite 107 **Tulsa, Oklahoma**	**74105**
(Address of Principal Executive Offices)	(Zip Code)

(918) 747-6060

(Issuer's Telephone Number, Including Area Code)

Securities registered under Section 12(b) of the Exchange Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common - $0.001 Par Value	American Stock Exchange

Securities registered under Section 12(g) of the Exchange Act: None

Check whether the issuer: (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act 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. Yes |**X**| No |_|

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B is not contained in this form, and no disclosure will be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-KSB or any amendment to this Form 10-KSB. |**X**|

State issuer's revenues for its most recent fiscal year. $8,453,739

As of March 10, 2005, the aggregate market value of the common voting stock held by non-affiliates of the issuer, based upon the closing stock price of $12.61 per share, was approximately $97,905,351. As of March 10, 2005, the issuer had outstanding 10,194,304 shares of common stock ($0.001 par value).

Transitional Small Business Disclosure Format (check one): Yes |_| No |**X**|

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PART I

Explanatory Note

The purpose of this Amendment No. 1 to the Annual Report on Form 10-KSB of Arena Resources, Inc. for the year ended December 31, 2004 (the Original Form 10-KSB) is to clarify the disclosure made in Item 8A regarding our controls and procedures.

This Amendment No. 1 amends and restates in its entirety Part II, Item 8A of the Original Form 10-KSB. This Amendment No. 1 continues to reflect circumstances as of the date and time of the filing of the Original Form 10-KSB and does not reflect events occurring after the filing of the Original Form 10-KSB or modify or update any other disclosures in any way.

Forward Looking Statements

All statements, other than statements of historical fact included in this Annual Report on Form 10-KSB (herein, Annual Report) regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words could, believe, anticipate, intend, estimate, expe project and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. All forward-looking statements speak only as of the date of this Annual Report. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this Annual Report. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Unless the context otherwise requires, references in this Annual Report to Arena, we, us, our or ours refer to Arena Resources, Inc.

PART I

Item 1: **Description of Business**

General

Arena Resources, Inc. was incorporated in Nevada on August 31, 2000. Our principal executive offices are located at 4920 South Lewis Avenue, Suite 107, Tulsa, Oklahoma 74105, and our telephone number is (918) 747-6060.

We are engaged in oil and natural gas acquisition, exploration, development and production, with activities currently in Oklahoma, Texas, New Mexico and Kansas. Our focus will be on developing our existing properties, while continuing to pursue acquisitions of oil and gas properties with upside potential.

Business Development

Since our inception in August 2000, we have built our asset base and achieved growth primarily through property acquisitions. From our inception through December 31, 2004, we have increased our proved reserves to approximately 21.2 million Boe (barrel of oil equivalent), through the acquisition of interests in 12 leases, which have net revenue interests ranging from 24.5% to 81.32%. As of December 31, 2004, our estimated proved reserves had a pre-tax PV10 (present value of future net revenues before income taxes discounted at 10%) of approximately $302 million. We spent approximately $29.4 million on acquisitions and capital projects during 2003 and 2004.

We have a portfolio of oil and natural gas reserves, with approximately 92% of our proved reserves consisting of oil and approximately 8% consisting of natural gas. Approximately 24.1% of our proved reserves are classified as proved developed producing, or PDP. Approximately 1.7% of our proved reserves are classified as proved developed non-producing, or PDNP, and approximately 74.2% are classified as proved undeveloped, or PUD.

Competitive Business Conditions

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. The majority of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry.

Current competitive factors in the domestic oil and gas industry are unique. The actual price range of crude oil is largely established by major international producers. Pricing for natural gas is more regional. Because the current domestic demand for oil and gas exceeds supply, we believe there is little risk that all current production will not be sold at relatively fixed prices. To this extent we do not believe we are directly competitive with other producers, nor is there any significant risk that we could not sell all our current production at current prices with a reasonable profit margin. The risk of domestic overproduction at current prices is not deemed significant. However, more favorable prices can usually be negotiated for larger quantities of oil and/or gas product. In this respect, while we believe we have a price disadvantage when compared to larger producers, we view our primary pricing risk to be related to a potential decline in international prices to a level which could render our current production uneconomical.

We are presently committed to use the services of the existing gathering companies in our present areas of production. This potentially gives such gathering companies certain short-term relative monopolistic powers to set gathering and transportation costs, because obtaining the services of an alternative gathering company would require substantial additional costs (since an alternative gathering would be required to lay new pipeline and/or obtain new rights of way to any lease from which we are selling production).

Major Customers

We principally sell our oil and natural gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For fiscal year 2004, two customers were responsible for generating 74% or more of our total oil and natural gas sales. These two customers were Plains Marketing, L.P., accounting for approximately 31% of total sales and Navajo Refining Company, accounting for approximately 43% of total sales. However, we believe that the loss of either of these customers would not materially impact our business, because we could readily find other purchasers for our oil and gas as produced.

Governmental Regulations

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission, or the FERC, regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state.

Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors. Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors.

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Compliance and Risks

Our oil and natural gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Historically, most of the environmental regulation of oil and gas production has been left to state regulatory boards or agencies in those jurisdictions where there is significant gas and oil production, with limited direct regulation by such federal agencies as the Environmental Protection Agency. However, while we believe this generally to be the case for our production activities in Oklahoma, Texas, New Mexico and Kansas, there are various regulations issued by the Environmental Protection Agency (EPA) and other governmental agencies that would govern significant spills, blow-outs, or uncontrolled emissions.

In Oklahoma, Texas, New Mexico and Kansas specific oil and gas regulations apply to the drilling, completion and operations of wells, and the disposal of waste oil and salt water. There are also procedures incident to the plugging and abandonment of dry holes or other non-operational wells, all as governed by the applicable governing state agency.

At the federal level, among the more significant laws and regulations that may affect our business and the oil and gas industry are: The Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as CERCLA or Superfund; the Oil Pollution Act of 1990; the Resource Conservation and Recovery Act, also known as RCRA, ; the Clean Air Act; Federal Water Pollution Control Act of 1972, or the Clean Water Act; and the Safe Drinking Water Act of 1974.

Compliance with these regulations may constitute a significant cost and effort for us. No specific accounting for environmental compliance has been maintained or projected by us at this time. We are not presently aware of any environmental demands, claims, or adverse actions, litigation or administrative proceedings in which either us or our acquired properties are involved or subject to, or arising out of any predecessor operations.

In the event of a breach of environmental regulations, these environmental regulatory agencies have a broad range of alternative or cumulative remedies which include: ordering a clean-up of any spills or waste material and restoration of the soil or water to conditions existing prior to the environmental violation; fines; or enjoining further drilling, completion or production activities. In certain egregious situations the agencies may also pursue criminal remedies against us or our principal officers.

Current Employees

As of December 31, 2004, we had ten full-time employees, including one petroleum engineer. Our employees are not represented by any labor union. We consider our relations with our employees to be satisfactory and have never experienced a work stoppage or strike.

We retain certain engineers, geologists, landmen, pumpers and other personnel on a contract or fee basis as necessary for our operations.

Item 2: Description of Property

General Background

Since our inception in late August 2000, we have begun to build a solid asset base and achieved steady growth, primarily through property acquisitions, but with some exploitation activities. From our inception through December 31, 2004, our proved reserves have grown to 21,217,254 Boe, at an average acquisition/drilling cost of $1.56 per Boe. As of December 31, 2004, our estimated proved reserves had a pre-tax PV10 value of approximately $302 million, approximately 44% of which came from properties located in New Mexico, approximately 42% from our properties in Texas, approximately 12% from our properties in Oklahoma and approximately 2% from our properties in Kansas. We spent approximately $28.3 million on capital projects during 2003 and 2004. We expect to further develop these properties through additional drilling. Our capital budget for 2005 is approximately $15 million for development of existing properties. Although our focus will be on development of our existing properties, we also intend to continue seeking acquisition opportunities which compliment our current portfolio. We intend to fund our development activity primarily through use of cash flow from operations and cash on hand, while potential drawings on our credit facility and proceeds from future equity transactions would also be available for development projects or future acquisitions. We believe that our acquisition expertise, together with our operating experience and efficient cost structure, provides us with the potential to continue our growth.

We have a portfolio of oil and natural gas reserves, with approximately 92% of our proved reserves consisting of oil and approximately 8% consisting of natural gas. Approximately 24.1% of our proved reserves are classified as proved developed producing properties. Approximately 1.7% of our proved reserves are classified as proved developed nonproducing, and approximately 74.2% are classified as proved undeveloped.

The following table summarizes our total net proved reserves and pre-tax PV10 value as of December 31, 2004.

Geographic Area	Oil (Bbl)	Natural Gas (Mcf)	Total (Boe)	Pre-Tax PV10 Value
New Mexico	8,659,448	4,165,346	9,353,672	$ 132,918,983
Texas	7,777,328	2,204,548	8,144,753	127,273,059
Oklahoma	3,113,888	168,756	3,142,014	36,583,892
Kansas	--	3,460,891	576,815	5,680,048
Total	19,550,664	9,999,541	21,217,254	$ 302,455,982

Proved Reserves

Our 21,217,254 Boe of proved reserves, which consist of approximately 92% oil and 8% natural gas, are summarized below as of December 31, 2004, on a net pre-tax PV10 value basis. Our reserve estimates have not been filed with any Federal authority or agency (other than the SEC).

As of December 31, 2004, New Mexico proved reserves had a net pre-tax PV10 value of $132.9 million, our proved reserves in Texas had a net pre-tax PV10 value of $127.2 million, our proved reserves in Oklahoma had a net pre-tax PV10 value of $36.6 million and our proved reserves in Kansas had a net pre-tax PV10 value of $5.7 million.

As of December 31, 2004, approximately 24.1% of the 21.2 million Boe of proved reserves have been classified as proved developed producing, or PDP . Proved developed non-producing, or PDNP , and proved undeveloped, or PUD , reserves constitute 1.7% and 74.2%, respectively, of the proved reserves as of December 31, 2004.

Total proved reserves had a net pre-tax PV10 value as of December 31, 2004 of approximately $302 million, 18.6% or $56.1 million of which is associated with the PDP reserves. An additional $4.7 million is associated with the PDNP reserves ($60.8 million for total proved developed reserves, or 20.1% of total proved reserves pre-tax PV10 value) and $241.6 million is associated with PUD reserves.

Our proved reserves as of December 31, 2004 are summarized in the table below.

	Oil (Bbl)	Gas (Mcf)	Total (Boe)	% of Total Proved	Pre-tax PV10 (In thousands)	Future Capital Expenditures (in thousands)
New Mexico:						
PDP	2,273,402	2,070,556	2,618,495	12%	$ 31,268	$ -
PDNP	326,902	250,734	368,691	2%	4,696	-
PUD	6,059,144	1,844,056	6,366,487	30%	96,955	11,541
Total Proved:	8,659,448	4,165,346	9,353,672	44%	$ 132,919	$ 11,541
Texas:						
PDP	1,661,082	584,328	1,758,470	8%	$ 17,293	$ -
PDNP	-	-	-	0%	-	-
PUD	6,116,246	1,620,220	6,386,283	30%	109,980	44,684
Total Proved:	7,777,328	2,204,548	8,144,753	38%	$ 127,273	$ 44,684

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Oklahoma:								
PDP	459,907	168,756	488,033	3%	$	4,731	$	-
PDNP	-	-	-	0%		-		-
PUD	2,653,981	-	2,653,981	12%		31,853		5,375
Total Proved:	3,113,888	168,756	3,142,014	15%	$	36,584	$	5,375
Kansas:								
PDP	-	1,540,891	256,815	1%	$	2,818	$	-
PDNP	-	-	-	0%		-		-
PUD	-	1,920,000	320,000	2%		2,862		375
Total Proved:	-	3,460,891	576,815	3%	$	5,680	$	375
Total:								
PDP	4,394,391	4,364,531	5,121,813	24%	$	56,110	$	-
PDNP	326,902	250,734	368,691	2%		4,696		-
PUD	14,829,371	5,384,276	15,726,750	74%		241,650		61,975
Total Proved:	19,550,664	9,999,541	21,217,254	100%	$	302,456	$	61,975

Estimated Costs Related to Conversion of Proved Undeveloped Reserves to Proved Developed Reserves

The following table indicates projected reserves that we currently estimate will be converted from proved undeveloped to proved developed, as well as the estimated costs per year involved in such development.

Year	Estimated Oil Reserves Developed (Bbls)	Estimated Gas Reserves Developed (Mcf)	Total Boe		Estimated Development Costs[(1)]
2005	3,108,084	2,159,540	3,468,007	$	12,406,208
2006	6,041,222	1,832,581	6,346,652		22,620,434
2007	4,517,791	1,056,016	4,693,794		16,532,000
	13,667,097	5,048,137	14,508,453		51,558,642

(1) The amount shown for 2005 differs from the Capital Expenditures budgeted as described elsewhere in this document. The difference is the result of Arena owning less than 100% of the working interest in all of the properties which are being developed. The amount shown here and in our reserve analysis constitutes the portion attributable to our working interest. However, if our working interest partners elected not to participate in the development planned, we would be responsible for the full $15 million.

Production

Our estimated average daily production for the month of December, 2004, is summarized below. These tables indicate the percentage of our estimated December 2004 average daily production of 999 Boe/d attributable to each state and to oil versus natural gas production.

State	Average Daily Production	Oil	Natural Gas
New Mexico	48.99%	43.15%	5.84%
Texas	24.40%	22.99%	1.41%
Oklahoma	22.21%	20.15%	2.06%
Kansas	4.40%	0.00%	4.40%
Total	100%	86%	14%

Summary of Oil and Natural Gas Properties and Projects

Significant New Mexico Operations

Seven Rivers Queen Unit Lea County, New Mexico. We acquired a 70.6% working interest and a 56.48% net revenue interest in this property in May 2003. This lease was acquired from Permian Resources Holding, Inc., an unaffiliated company, for a cash payment of $900,000. The remaining working interest is owned by unaffiliated parties. There are currently 43 producing wells on this lease, and we believe it can support six to eight possible infill wells (additional wells within the spacing requirements of the unit), as well as some untested formations in shallow sand. This lease consists of approximately 2,240 acres and is held by production.

North Benson Queen Unit Eddy County, New Mexico. In October 2003 we acquired a 100% working interest and a 78.15% net revenue interest in this lease, which currently has 21 producing wells. This lease was acquired from United Resources, L.P., an unaffiliated company, for a cash payment of $500,000. The lease covers approximately 1,800 acres, and we currently anticipate it can support up to 23 additional wells, which are included in our estimate of PUD. This lease is held by production.

The North Benson Queen Unit Waterflood will require additional volumes of water to support the waterflood expansion. A sufficient and economical source of water has been identified. A water line of approximately four miles in length will be constructed across Bureau of Land Management lands to transport the water to the North Benson Queen Unit. Permit applications must be submitted to the Bureau of Land Management and are usually granted within ninety days of application submittal. The construction of the water line should require approximately thirty days at a cost of $250,000. The permit application will be submitted in the second quarter 2005 with construction slated for the summer of 2005. The development of the North Benson Queen Unit waterflood is scheduled for 2006 at estimated costs of $5,732,000.

East Hobbs Unit Lea County, New Mexico. In May 2004 we acquired an 82.24% working interest and a 67.6% net revenue interest in this lease primarily from EnerQuest Oil and Gas, Ltd., an unaffiliated company, for a cash payment of $10,008,440. Although the Purchase and Sales Agreement transferred the revenue and the related operating costs from East Hobbs to us beginning March 1, 2004, Arena did not control the property interests until May 7, 2004. As a result, the acquisition date for accounting purposes was May 7, 2004 and the operations of East Hobbs operations were included in our results of operations from May 7, 2004. Revenues and operating costs for the months of March and April were estimated and treated as adjustments to the purchase price. This lease covers approximately 920 acres. At the date of acquisition, there were 20 operating oil and gas wells. We drilled an additional six wells, all of which were successfully completed, and washed down one other well during 2004. We believe this property can support up to six additional wells, which are included in our estimate of PUD. This lease is held by production.

Significant Texas Operations

Y6 Lease Fisher County, Texas. We acquired a 100% working interest and an 80% net revenue interest in this lease in June 2001. This lease was acquired from Durango Operating Company, Inc. an unaffiliated company, for a cash payment of $750,000. There are currently 12 producing wells on this lease. A portion of this property has been waterflooded, and when we begin our future development operations on this property, we plan to waterflood the remaining acreage. A waterflood operation is a method of secondary recovery in which water is injected into the reservoir formation to displace residual oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells. This potential waterflood project (and the estimated $1 million cost thereof) is included as PUD in our reserve report. This lease consists of approximately 1,697 acres and is held by production.

Dodson Lease Montague County, Texas. We purchased a 100% working interest and an 81.25% net revenue interest in this lease in June 2002. This lease was acquired from Nocona minerals Partnership, an unaffiliated company, for a cash payment of $200,000. There are currently three producing wells and nine other wells on this approximately 570 acre lease, all of which is held by production.

West San Andres Unit Yoakum County, Texas. In October 2003 we acquired a 100% working interest and a 79.60% net revenue interest in this lease from Permian Resources, Inc. an unaffiliated company, for a cash payment of $500,000. The lease covers approximately 1,200 acres, and currently has 10 producing wells. We believe it can support up to four additional wells, which are included in our estimate of PUD. This lease is held by production. In 2004 we contracted for the drilling of one well on this property, which was not commenced until January 2005.

Fuhrman-Mascho leases Andrews County, Texas. In December 2004 we acquired a 100% working interest and a 75% net revenue interest in these leases from four entities; Paul D. Friemel & Assoc, Inc., Compostella Oil Company, Redco Oil & Gas Inc. and Terry N. Stevens, Inc., all unaffiliated companies. The purchase price, including acquisition costs, was $10,966,495 and consisted of $9,667,381 of cash paid to the sellers, $44,421 in cash acquisition costs, 180,013 shares of the Company s common stock, valued at $1,260,091, or $7.00 per share, and the issuance of put and call options with a net value of $24,602. These leases cover approximately 11,300 acres. We believe it can support up to 130 additional wells, which are included in our estimate of PUD. These leases are held by production.

Significant Oklahoma Operations

Casey Lease Muskogee County, Oklahoma. The Casey Lease originally consisted of a 40% working interest contributed by our two principal shareholders. We subsequently acquired additional interests in this lease, so that presently we have a 94% working interest, and an approximately 74.48% net revenue interest in the well on this property. Net revenue interest is the owner s percentage share of the monthly income realized from the sale of a well s produced oil and gas. The net revenue interest is a lesser number as compared to the working interest, due to the mineral owner royalty and other overriding royalties on the well.

In May 2001, we acquired an additional 30% working interest in the lease from a group of interest holders represented by Petro Consultants, Inc. The additional working interest was valued at $300,000 and was acquired by the issuance of 80,000 shares of common stock valued at $1.75 per share totaling $140,000, the assumption of a $50,000 obligation of the seller and the issuance of a note payable for $110,000. This note was subsequently settled through cash payments of $45,000 and the issuance of an additional 37,143 shares of common stock valued at $1.75 per share totaling $65,000. The $50,000 liability assumed from the seller related to the seller s previous obligation to the operator of the properties and has been paid.

In October 2001, we acquired an additional 24% working interest and a 2½% overriding royalty interest in the Casey lease from a group of interest holders represented by Petro Consultants, Inc. The acquired interests were valued at $266,250 and were purchased by the issuance of 81,857 shares of common stock valued at $1.75 per share totaling $143,250, a cash payment of $90,000 and the issuance of a note payable for $33,000. The note was subsequently paid.

The remaining working interest in the Casey lease is owned by an unaffiliated party. This lease consists of approximately 160 acres. In December 2003 we temporarily shut-in this gas well. Subsequent to December 31, 2004, we sold the Casey lease to an unrelated party.

Ona Morrow Sand Unit Cimarron and Texas Counties, Oklahoma. We own a 100% working interest and an 81.32% net revenue interest in this lease which has been producing since our acquisition in July 2002. This lease was acquired from Bass Petroleum, Inc., an unaffiliated company, for a cash payment of $735,000. This lease has approximately 2,120 acres and seven producing wells. We believe up to five additional locations may be suitable for drilling, which are included in our estimate of our PUD. This lease is held by production.

Eva South Morrow Sand Unit Texas County, Oklahoma. We own a 100% working interest and an 85.41% net revenue interest in this lease which was also acquired in July 2002. This lease was acquired from Ensign Operating Company, an unaffiliated company, for a cash payment of $827,500. The lease consists of approximately 489 acres and has seven producing wells, with a possibility for two additional wells, which have been included in our estimate of our PUD. This lease is held by production.

Midwell, Appleby, Smaltz and Hanes Leases Cimarron County, Oklahoma. We own 100% of the working interest and an 80% net revenue interest in these four leases acquired in September 2002. All have been producing leases since the date of our acquisition. The Midwell Appleby and Smaltz leases consist of approximately 1,640 acres with five producing wells, and we believe there are up to three additional drilling locations on these leases. The Hanes lease contains approximately 640 acres and four producing wells, with a possibility of up to two additional wells, which are included in our estimate of PUD. All of these leases are held by production.

Roy Hanes Lease Texas County, Oklahoma. We own a 24.5% working interest and a 21.44% net revenue interest in this lease, which is a property operated by XTO Energy, Inc, an unaffiliated company, who also owns the remaining working interest. The interest in this lease was acquired at the same time we acquired our interests in the Midwell, Appleby, Smaltz and Hanes leases, and there has been production on this lease since that time. This lease consists of approximately 640 acres, and is currently held by production.

The Midwell, Appleby, Smaltz, Hanes and Roy Hanes leases were acquired from Burk Royalty Co., Ltd. R.A. Kimball Property Co., Ltd. and Kimball Family Resources, Ltd., all unaffiliated companies. The cost of these leases was $550,179, with $100,000 paid in cash and the balance paid through our issuance of 99,885 shares of our common stock valued at $4.00 per share (the then current market value), and the issuance of put and call options with a net value to the sellers of $50,639.

Significant Kansas Operations

Koehn/Rexford Unit Haskell & Gray County, Kansas. This lease consists of approximately 640 acres. After entering into a farmout agreement with Bird Creek Resources, Inc., an unaffiliated company, we drilled and completed an initial gas well on this lease. Under the terms of this agreement, we agreed to drill one well and could drill additional wells on the property. In exchange for each well drilled, we will be assigned 100% of the working interest (80% of the net revenue interest) in the well and related oil and gas until payout of all costs of drilling, equipping and operating the well. After payout, our working interest in the wells and related oil and gas will decrease to 75% (60% of the net revenue interest).

In 2002, we successfully drilled one well at a cost of approximately $153,000 to drill, complete and connect to the pipeline and thus will have reached payout when we recover this amount from production. After payout, Bird Creek Resources, Inc. will own the remaining 25% working interest.

On March 20, 2002, we entered into a joint venture agreement with Petro Consultants, Inc., to drill and operate the well on the above-mentioned property. Under the terms of the agreement, Petro purchased 27% of the working interest in the well for $88,200. On May 20, 2002, after the well was successfully drilled, we issued 70,000 shares of common stock (valued at $1.26 per share) to Petro to repurchase the 27% working interest in the well.

In February 2004, we successfully drilled one additional well on this acreage at a cost of approximately $159,000 to drill, complete and connect to the pipeline and thus will have reached payout when we recover this amount from production. After payout, Bird Creek Resources, Inc. will own the remaining 25% working interest.

In November 2004, we completed the installation of a pipeline from our Koehn lease to a gatherer/purchased pipeline. Total cost on installation of the pipeline was approximately $144,000. The installation of this pipeline was necessary to be able to begin producing from our wells in that area. Production started on December 11, 2004.

Schmidt Unit Gray County, Kansas. During 2004 we leased an additional 640 acres offsetting our Koehn/Rexford Unit for a total of approximately $8,582. In November 2004, we successfully drilled one well on this acreage at a cost of approximately $183,520 to drill, complete and connect to the pipeline. We began producing from this well on December 23, 2004.

Beals Prospect Comanche County, Kansas. In July 2003 we acquired a 100% working interest and an 80.5% net revenue interest in this lease, consisting of 1,560 acres. This lease was acquired from Bengalia Land and Cattle Company., an unaffiliated party, for a cash payment of $60,000. During August 2003 we drilled one well on this acreage, which was unsuccessful and was plugged and abandoned. This lease will expire in April 2006 if not then held by production.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2004 by region (net acreage is our percentage ownership of gross acreage). Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
New Mexico	4,960	3,294	--	--	4,960	3,294
Texas	14,767	11,251	--	--	14,767	11,251
Oklahoma	5,689	4,242	--	--	5,689	4,242
Kansas	1,280	1,024	1,560	1,256	2,840	2,280
Total	26,696	19,811	1,560	1,256	28,256	21,067

Production History

The following table presents the historical information about our produced natural gas and oil volumes.

	Year Ended December 31,		
	2002	**2003**	**2004**
Oil production (Bbls)	58,717	117,646	195,166
Natural gas production (Mcf)	46,819	67,329	169,002
Total production (Boe)	66,520	128,868	223,333
Daily production (Boe/d)	182	353	612
Average sales price:			
Oil (per Bbl)	$ 26.09	$ 29.06	$ 39.26
Natural gas (per Mcf)	2.67	3.67	4.93
Total (per Boe)	24.91	28.44	38.09
Average production cost (per Boe)	$ 8.94	$ 8.92	$ 8.90

Productive Wells

The following table presents our ownership at December 31, 2004, in productive oil and natural gas wells by region (a net well is our percentage ownership of a gross well).

	Oil Wells		Gas wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
New Mexico	93	60	-	-	93	60
Texas	182	138	-	-	182	138
Oklahoma	23	19	-	-	23	19
Kansas	-	-	3	2	3	2
Total	298	217	3	2	301	219

Drilling Activity

During 2004 we completed the drilling of nine wells, completed a wash down on one well and had contracted for the drilling of one additional well that was not commenced until January 2005. Two of the wells were drilled and completed in Gray County, Kansas, offsetting the Koehn well that was drilled in 2002. Both of these wells were placed into production in December 2004. The third newly drilled well is on our Dodson property in Montague County, Texas. This well has been completed but has not yet been placed into production. The remaining six newly drilled wells and the one washed down well are in on our East Hobbs San Andres Unit property in Lea County, New Mexico. All seven wells were completed have been placed into production. The well for which we had contracted for drilling that was commenced in January 2005 is on our West San Andres Unit property in Yoakum County, Texas. This well was drilled in January 2005 and completed in March 2005, but has not yet been placed into production.

Cost Information

We conduct our oil and natural gas activities entirely in the United States. Our average production costs, per Boe, were $8.94 in 2002, $8.92 in 2003 and $8.90 in 2004. Net costs capitalized during the years ended December 31, 2002, 2003 and 2004, related to our oil and natural gas producing activities are shown below.

	For the Years Ended December 31,		
	2002	**2003**	**2004**
Acquisition of proved properties	$ 2,659,832	$ 2,470,821	$ 21,063,816
Acquisition of unproved properties	-	147,000	43,082
Exploration costs	-	326,410	216,805
Development costs	579,153	849,864	4,027,754
Acquisition of support and office equipment	29,388	-	19,629
Asset retirement costs recognized upon adoption of SFAS No. 143	-	221,218	607,133
Total Costs Incurred	$ 3,268,373	$ 4,015,313	$ 25,978,219

Reserve Quantity Information

Our estimates of proved reserves and related valuations were based on reports prepared by Lee Keeling and Associates, Inc., independent petroleum and geological engineers, in accordance with the provisions of SFAS 69, Disclosures About Oil and Gas Producing Activities. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Our oil and natural gas reserves are attributable solely to properties within the United States. A summary of the changes in quantities of proved (developed and undeveloped) oil and natural gas reserves is shown below.

	Oil (Bbls)	**Natural Gas (Mcf)**
Balance, December 31, 2001	494,823	2,960,373
Purchase of minerals in place	3,597,156	1,676,706
Extensions and discoveries	--	--
Production	(58,717)	(46,819)
Revisions of estimates	80,674	(1,402,503)
Balance, December 31, 2002	4,113,937	3,187,757
Purchase of minerals in place	3,175	570,924
Extensions and discoveries	18,066	229,626
Production	(117,646)	(67,329)
Revisions of estimates	(139,546)	(512,224)
Balance, December 31, 2003	7,050,167	3,408,751
Purchase of minerals in place	8,764,087	6,431,440
Extensions and discoveries	-	640,000
Production	(195,167)	(169,002)
Revisions of estimates	3,931,577	(311,648)
Balance, December 31, 2004	19,550,664	9,999,541

Our proved oil and natural gas reserves are shown below.

	For the Years Ended December 31,		
	2002	2003	2004
Oil (Bbls)			
Developed	750,463	1,580,521	4,721,293
Undeveloped	3,363,473	5,469,646	14,829,371
Total	4,113,936	7,050,167	19,550,664
Natural Gas (Mcf)			
Developed	1,160,639	1,612,738	4,615,265
Undeveloped	2,027,118	1,796,016	5,384,276
Total	3,187,757	3,408,754	9,999,541
Total (Boe)			
Developed	943,904	1,849,311	5,490,504
Undeveloped	3,701,326	5,768,972	15,726,750
Total	4,645,230	7,618,283	21,217,254

Standardized Measure of Discounted Future Net Cash Flows

Our standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and changes in the standardized measure as described below were prepared in accordance with the provisions of SFAS 69. Future cash inflows were computed by applying year-end prices to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in producing and developing the proved oil and natural gas reserves at year end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pre-tax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10 percent annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of our oil and natural gas properties.

The standardized measure of discounted future net cash flows relating to the proved oil and natural gas reserves are shown below.

	December 31,	
	2003	2004
Future cash inflow	$ 218,026,254	$ 814,346,791
Future production costs	(64,157,199)	(171,518,828)
Future development costs	(13,609,584)	(61,975,106)
Future income tax expense	(45,778,941)	(187,392,403)
Future net cash flows	94,480,730	393,460,454
10% annual discount for estimated timing of cash flows	(49,474,633)	(188,219,704)
Standardized measure of discounted future net cash flows	$ 45,006,097	$ 205,240,750

The changes in the standardized measure of discounted future net cash flows relating to the proved oil and natural gas reserves are shown below.

	For the Years Ended December 31,	
	2003	2004
Beginning of the year	$ 27,997,824	$ 45,006,097
Purchase of minerals in place	21,333,720	142,824,938
Extensions, discoveries and improved recovery, less related costs	691,469	347,652
Development costs incurred during the year	320,102	5,387,638
Sales of oil and gas produced, net of production costs	(2,302,405)	(5,876,333)
Accretion of discount	3,012,793	4,882,064
Net change in prices and production costs	8,222,075	74,777,221
Net change in estimated future development costs	39,219	(3,187,159)
Revision of previous quantity estimates	(53,098)	42,149,044
Revision of estimated timing of cash flows	(5,468,732)	(27,509,967)
Net change in income taxes	(8,786,869)	(73,560,445)
End of the Year	$ 45,006,097	$ 205,240,750

Management s Business Strategy Related to Properties

Our goal is to increase stockholder value by investing in oil and gas projects with attractive rates of return on capital employed. We plan to achieve this goal by exploiting and developing our existing oil and natural gas properties and pursuing acquisitions of additional properties. Specifically, we have focused, and plan to continue to focus, on the following:

Developing and Exploiting Existing Properties. We believe that there is significant value to be created by drilling the identified undeveloped opportunities on our properties. We own interests in a total of 26,696 gross (19,810 net) developed acres and operate essentially all of the net pre-tax PV10 value of our proved undeveloped reserves. In addition, as of December 31, 2004, we owned interests in approximately 1,560 gross undeveloped acres (1,256 net). We believe that our current and future cash flow will enable us to undertake the exploitation of our properties through additional drilling activities. Our expected capital budget for development of existing properties in 2005 is approximately $15 million.

Pursuing Profitable Acquisitions. We have historically pursued acquisitions of properties that we believe to have exploitation and development potential comparable to our existing inventory of drilling locations. We have developed and refined an acquisition program designed to increase reserves and complement our existing core properties. We have an experienced team of management and engineering professionals who identify and evaluate acquisition opportunities, negotiate and close purchases and manage acquired properties. From August 2000 through December 31, 2004, we acquired 12 leases at an aggregate acquisition and enhancement cost of approximately $33 million, representing approximately 21.2 million Boe of proved reserves (at an average cost of $1.56 per Boe). While our emphasis in 2005 and beyond is anticipated to focus on the further development our existing properties, we will continue to look for properties with both existing cash flow from production and future development potential.

Controlling Costs through Efficient Operation of Existing Properties. We operate essentially 100% of the pre-tax PV10 value of our total proved reserves, which we believe enables us to better manage expenses, capital allocation and the decision-making processes related to our exploitation and exploration activities. For the year ended December 31, 2004, our lease operating expense per Boe averaged $8.90 and general and administrative costs averaged $3.02 per Boe produced.

Other Properties and Commitments

We currently lease our principal executive offices in Tulsa, Oklahoma. At December 31, 2004, the lease was for approximately 2,352 square feet of office space, at an annual rental of $20,400. Subsequent to December 31, 2004 and effective March 1, 2005, we leased an additional 385 square feet of office space at the same location and extended the lease through January 1, 2006. Our annual rental for 2005 will be $24,400. The current facilities are believed adequate for our current operations.

Item 3: Legal Proceedings

In the ordinary course of business, we may be, from time to time, a claimant or a defendant in various legal proceedings. We do not presently have any litigation pending or threatened.

Item 4: Submission of Matters to a Vote of Security Holders

Our annual shareholders meeting was held on December 21, 2004. The shareholder s re-elected Messrs. Stanley M. McCabe, Lloyd T. Rochford, Charles M. Crawford, Chris V. Kemendo, Jr. and Clayton E. Woodrum as Directors with terms ending in 2005. The shareholders further approved an amendment to the Company s executive stock option plan to increase the number of shares of Common Stock that may be granted under the plan from 1,000,000 to 1,500,000, and to provide discretionary acceleration of vesting of options previously granted. Following is a chart reflecting the votes cast for each of the elected directors, as well as for the amendment to the stock option plan:

	Votes for	Votes against	Abstain
Lloyd T. Rochford	5,556,002	-	11,001
Stanley M. McCabe	5,556,002	-	11,001
Charles M. Crawford	5,556,002	-	11,001
Chris V. Kemendo, Jr.	5,545,002	-	22,001
Clayton E. Woodrum	5,556,002	-	11,001
Amendment to option plan	5,473,992	93,011	438,038

PART II

Item 5: Market for Registrant s Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for our Common Stock

Since April 15, 2003, our common stock has been traded on the American Stock Exchange, under the symbol ARD . Prior to that time, our common stock traded on the OTC Bulletin Board. The following table shows the high and low sales prices for each quarter since listing on the American Stock Exchange, and the high and low bid prices prior to such time, during the last two years.

Period		High Sale or Bid		Low Sale or Bid
1st Quarter 2003	$	4.35	$	4.25
2nd Quarter 2003		5.99		4.35
3rd Quarter 2003		5.82		5.45
4th Quarter 2003		6.10		5.40
1st Quarter 2004	$	7.08	$	5.85
2nd Quarter 2004		9.65		6.98
3rd Quarter 2004		7.46		5.98
4th Quarter 2004		8.79		6.80
1st Quarter 2005 (through March 10, 2005)	$	13.40	$	8.35

Record Holders

As of March 1, 2005, there are approximately 1,481 holders of record of our common stock. Approximately 24%, or 2,430,200 shares of the 10,194,304 shares issued and outstanding as of such date are held by management or affiliated parties.

Dividend Policy

We have not paid any dividends on our common stock during the last two years, and we do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. In addition, our credit facility prohibits us from paying dividends.

Securities Authorized for Issuance Under Equity Compensation Plans

In March 2003, our board of directors adopted an executive stock option plan which was subsequently approved by our shareholders at our annual meeting in July 2003, and which was amended by our shareholders at our annual meeting in 2004. Information regarding this plan and the options that have been granted under this plan may be found in this Annual Report under Part III, Items 10 and 11.

Recent Sales of Unregistered Securities

Throughout 2004, we issued 78,300 shares of our common stock upon the exercise of previously issued warrants at either $1.75 per share or $5.00 per share. These shares were issued in a transaction not involving a public offering and were issued in reliance upon the exemption from registration provided by Section 4(2) of the Securities Act of 1933. The persons to whom the shares were issued had access to full information concerning us and represented that he acquired the shares for his own account and not for the purpose of distribution. The certificates for the shares contain a restrictive legend advising that the shares may not be offered for sale, sold or otherwise transferred without having first been registered under the 1933 Act or pursuant to an exemption from registration under the 1933 Act. There was no underwriter involved in these transactions.

In August 2004, we issued 40,000 shares of common stock valued at $5.11 per share, or $204,533, as compensation to a consultant utilized in connection with our acquisition of the East Hobbs San Andres Unit in Eddy County, New Mexico. The shares were issued in a transaction not involving a public offering and were issued in reliance upon the exemption from registration provided by Section 4(2) of the Securities Act of 1933. The person to whom the shares were issued had access to full information concerning us and represented that he acquired the shares for his own account and not for the purpose of distribution. The certificates for the shares contain a restrictive legend advising that the shares may not be offered for sale, sold or otherwise transferred without having first been registered under the 1933 Act or pursuant to an exemption from registration under the 1933 Act. There was no underwriter involved in this transaction.

In December 2004, we issued 30,000 shares of common stock valued at $7.00 per share, or $210,000, as compensation to a consultant utilized in connection with our acquisition of the Fuhrman Mascho leases in Andrews County, Texas. The shares were issued in a transaction not involving a public offering and were issued in reliance upon the exemption from registration provided by Section 4(2) of the Securities Act of 1933. The person to whom the shares were issued had access to full information concerning us and represented that he acquired the shares for his own account and not for the purpose of distribution. The certificates for the shares contain a restrictive legend advising that the shares may not be offered for sale, sold or otherwise transferred without having first been registered under the 1933 Act or pursuant to an exemption from registration under the 1933 Act. There was no underwriter involved in this transaction.

Issuer Repurchases

We did not make any repurchases of our equity securities during the quarter ending December 31, 2004.

Item 6: Management s Discussion and Analysis of Financial Condition and Results of Operations

Introduction

The following discussion and analysis should be read in conjunction with our accompanying financial statements and the notes to those financial statements included elsewhere in this Annual Report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this Annual Report.

Overview

We are engaged in oil and natural gas acquisition, exploration and exploitation activities in the states of Oklahoma, Texas, New Mexico and Kansas. Over the last four years, we have emphasized the acquisition of properties that provided current production and significant upside potential through further development.

We have increased our reserves significantly by investing approximately $25.4 million in acquisitions and enhancements in 2004, following total capital expenditures of approximately $4 million in 2003 and approximately $3.2 million in 2002.

Our capital budget for 2005 is approximately $15 million for development of existing properties. We also intend to continue seeking acquisition opportunities which compliment our current portfolio. We intend to fund our development activity primarily through use of cash flow from operations and cash on hand, while potential drawings on our credit facility and proceeds from future equity transactions would also be available for development projects or future acquisitions.

Our business plan has involved increasing our base of proven reserves until we have acquired a sufficient core to enable us to utilize cash from existing production to fund further development activities. When we originated our business plan we believed this would allow us to lessen our risks, including risks associated with borrowing funds to undertake exploration activities at an earlier time. As we have now increased our base of proven properties, and as oil and natural gas prices have recently significantly risen, we have initiated our development activities.

While our focus has shifted to include more development activity, we plan to continue our strategy of acquiring producing properties with additional development, exploitation and exploration potential. Our focus has been on acquiring operated properties (i.e. properties with respect to which we serve as the operator on behalf of all joint interest owners) so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non-operated property interests at attractive rates of return that provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they satisfy our general business plan. In addition, our willingness to acquire non-operated properties in new geographic regions may provide us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

In a worst case scenario, future drilling operations could be largely unsuccessful, oil and gas prices could sharply decline and/or other factors beyond our control could cause us to greatly modify or substantially curtail our development plans, which could negatively impact our earnings, cash flow and most likely the trading price of our securities, as well as the acceleration of debt repayment and a reduction in our borrowing base under our credit facilities.

Results of Operations

The following table sets forth selected operating data for the periods indicated:

	For the Years Ended December 31, 2002	2003	2004
Net production:			
Oil (Bbls)	58,717	117,646	195,116
Natural gas (Mcf)	46,819	67,329	169,002
Net sales:			
Oil	$ 1,532,045	$ 3,418,480	$ 7,661,006
Natural gas	124,992	246,997	821,124
Average sales price:			
Oil (per Bbl)	$ 26.09	$ 29.06	$ 39.26
Natural gas (per Mcf)	2.67	3.67	4.86
Production costs and expenses			
Lease operating expenses	$ 594,863	$ 1,149,136	$ 1,975,835
Production taxes	117,164	269,563	629,703
Depreciation, depletion and amortization expense	151,197	360,282	1,011,602
General and administrative expenses	248,018	557,576	670,325

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Oil and natural gas sales. Oil and natural gas sales revenue increased approximately $4.82 million to $8.48 million in 2004. Oil sales increased $4.42 million and natural gas sales increased $575,000. The oil sales increase was caused by a sales volume increase of 77,570 barrels in 2004, and a 35% increase in the average realized per barrel oil price from $29.06 in 2003 to $39.26 in 2004. The natural gas sales increase was caused by a sales volume increase of 101,673 Mcf in 2004 and a 34% increase in the average realized natural gas price per Mcf from $3.67 in 2003 to $4.86 in 2004. The volume increase for crude oil and natural gas primarily resulted from $26 million of capital expenditures during 2004, of which approximately $21 million were related to our acquisition of the East Hobbs and Fuhrman Mascho properties.

Lease operating expenses. Our aggregate lease operating expenses increased from $1,149,136 in 2003 to $1,975,835 2004, although such expenses on a Boe basis declined slightly from $8.92 in 2003 to $8.90 in 2004. This aggregate increase was the result of having the properties acquired in 2003 in our operations for a full year in 2004; acquiring new properties and accounting for them for a portion of the year in 2004 and cost increases. The decline on a per Boe basis is attributable to consolidation of resources available due to our growth.

Production taxes. Production taxes as a percentage of oil and natural gas sales were 7% during 2003 and remained steady at 7% in 2004. Production taxes vary from state to state. Therefore, these taxes are likely to vary in the future depending on the mix of production we generate from various states, and on the possibility that any state may raise its production tax.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased by $651,320 to $1,011,602 in 2004. The increase was a result of an increase in the average depreciation, depletion and amortization rate from $2.79 per Boe during 2003 to $4.47 per Boe during 2004. The increased depreciation, depletion and amortization was the result of increased sales volume and an increase in estimated future development costs.

General and administrative expenses. General and administrative expenses increased by $112,749 to $670,325 during 2004. This increase was primarily related to increases in compensation expense associated with an increase in personnel required to administer our growth, legal fees of $31,150, annual listing fees of $18,700, $16,095 in fees paid to Lee Keeling for 2003 reserve reports, fees related to obtaining our credit facility and letters of credit and directors fees.

Interest expense. Interest expense increased $117,138 to $155,936 in 2004. The increase was due to higher amounts of debt being outstanding during periods of the year in 2004.

Income tax expense. Our effective tax rate was 37% during 2004 and 37% during 2003.

Cumulative change in accounting principle. Effective January 1, 2003, we adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies to legal obligations associated with the retirement of long-lived assets and requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. This statement applies directly to the plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 8.08%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, we recorded an increase to our discounted abandonment liability of $236,718, increased proved property cost by $217,878, and recognized a one-time cumulative effect charge of $11,813 (net of a related tax effect of $7,027). The effect of adopting this accounting principle was a $24,873 after tax decrease in net income during 2003.

Net income. Net income increased from $809,498 for 2003 to $2,580,017 for 2004. The primary reasons for this increase include higher crude oil and natural gas prices between periods and an increase in volumes sold, partially offset by higher lease operating expense, tax expense and general and administrative expenses due to our growth.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Oil and natural gas sales. Oil and natural gas sales revenue increased approximately $2 million to $3.66 million in 2003. Oil sales increased $1.89 million and natural gas sales increased $122,000. The oil sales increase was caused by a sales volume increase of 58,929 barrels in 2003, and a 11% increase in the average realized per barrel oil price from $26.09 in 2002 to $29.06 in 2003. The natural gas sales increase was caused by a sales volume increase of 20,510 Mcf in 2003 and a 37% increase in the average realized natural gas price per Mcf from $2.67 in 2002 to $3.67 in 2003. The volume increase for crude oil and natural gas primarily resulted from $3 million of capital expenditures during 2003.

Lease operating expenses. Our aggregate lease operating expenses increased from $594,863 or $8.94 per Boe in 2002 to $1,149,136 or $8.92 per Boe in 2003, although such expenses on a per Boe basis declined slightly from $8.94 in 2002 to $8.92 in 2003. This aggregate increase was a result of higher operating costs on properties acquired in 2003. The decline on a per Boe basis is attributable to consolidation of resources available due to our growth. While it is possible that this increase will continue in the future as we acquire additional properties, because each property is individual in its characteristics, at this time, apart from normal increases associated with inflation in general, we cannot specifically identify this increase to be a trend.

Production taxes. Production taxes as a percentage of oil and natural gas sales were 7% during 2002 and remained steady at 7% in 2003. Production taxes vary from state to state. Therefore, these taxes are likely to vary in the future depending on the mix of production we generate from various states, and on the possibility that any state may raise its production tax.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased by $209,085 to $360,282 in 2003. The increase was a result of an increase in the average depreciation, depletion and amortization rate from $2.27 per Boe during 2002 to $2.79 per Boe during 2003. The increased depreciation, depletion and amortization was the result of increased sales volume and an increase in estimated future development costs.

General and administrative expenses. General and administrative expenses increased by $309,558 to $557,576 during 2003. This increase was primarily related to increases in compensation expense associated with an increase in personnel required to administer our growth (specifically, the addition of our in-house engineer), listing fees of $56,625 paid to the American Stock Exchange, $61,280 in fees paid to a stock research analyst, fees related to obtaining our credit facility and letters of credit and directors fees.

Interest expense. Interest expense increased $22,875 to $38,798 in 2003. The increase was due to our debt being outstanding for the entire year in 2003, as opposed to being outstanding for a partial year in 2002.

Income tax expense. Our effective tax rate was 37% during 2003 and 32% during 2002. The effective rate was higher during 2003 due to having more income subject to income tax, higher state income tax and no benefit of operating loss carry forwards in 2003.

Cumulative change in accounting principle. Effective January 1, 2003, we adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies to legal obligations associated with the retirement of long-lived assets and requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. This statement applies directly to the plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 8.08%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, we recorded an increase to our discounted abandonment liability of $236,718, increased proved property cost by $217,878, and recognized a one-time cumulative effect charge of $11,813 (net of a related tax effect of $7,027). The effect of adopting this accounting principle was a $24,873 after tax decrease in net income during 2003.

Net income. Net income increased from $387,049 for 2002 before preferred stock dividends, to $809,498 for 2003. The primary reasons for this increase include higher crude oil and natural gas prices between periods and an increase in volumes sold, partially offset by higher lease operating expense, tax expense and general and administrative expenses due to our growth.

Liquidity and Capital Resources

Historical Financing. We have historically funded our operations through loans from our executive officers, our initial public offering of stock in 2001, private equity offerings of our stock and warrants and our Secondary offering of common stock and warrants which we closed in August 2004.

Credit Facility. On April 14, 2004, we established a new $15,000,000 credit facility with our principal lenders with an $8,500,000 initial borrowing base. In November 2004, we entered into an agreement that increased the facility to $25,000,000, with an increased borrowing base of $15,000,000. Any increases in the borrowing base are subject to written consent by the financial institution. The interest rate is a floating rate equal to the 30, 60 or 90 day LIBOR rate plus 2.25%, currently 5.04% per annum, and is payable monthly. Annual fees for the facility are 1/8 of one percent of the unused portion of the borrowing base. Amounts borrowed under the revolving credit facility are due in April 2007. The revolving credit facility is secured by our principal mineral interests. In order to obtain the revolving credit facility, loans from two officers were subordinated to the position of the bank. We are required under the terms of the credit facility to maintain a tangible net worth of $12,000,000, maintain a 5-to-1 ratio of income before interest, taxes, depreciation, depletion and amortization to interest expense and maintain a current asset to current liability ratio of 1-to-1, not including the $2,000,000 bridge financing arrangement discussed below. On May 7, 2004, we drew $8,008,440 under this revolving credit facility to fund the acquisition of the East Hobbs San Andres Property interests. During August 2004, utilizing cash flow from operations and proceeds from the recent secondary offering of common stock and warrants, we paid $8,008,440 of principal and related accrued interest due on the credit facility. During December 2004, we drew $9,000,000 under this revolving credit facility to fund the acquisition of the Fuhrman Mascho leases and $1,000,000 to help fund development activities. An additional $299,029 is reserved under the revolving credit facility as collateral for standby letters of credit issued to various states.

On April 14, 2004, we also entered into to a bridge financing arrangement for $2,000,000 from our lender. On April 21, 2004, we borrowed $1,000,000 under the terms of the bridge financing agreement to fund a cash deposit made on the East Hobbs San Andres Property interests. On May 7, 2004, we borrowed an additional $1,000,000 under the terms of the bridge financing arrangement to fund the acquisition of the East Hobbs San Andres Property interests. The interest rate on the bridge financing arrangement is a floating rate equal to the 30, 60 or 90 day LIBOR rate plus 2.25%, currently 3.42% per annum, and is payable monthly. This arrangement was established for a one-time purpose to satisfy the funding requirements of the East Hobbs San Andres Property acquisition. The original agreement expired June 30, 2004 and was subsequently extended to July 31, 2004. The bridge financing arrangement was guaranteed by two of the Company s officers. During August 2004, utilizing cash flow from operations and proceeds from the recent public offering of common stock and warrants, the Company paid $2,000,000 of principal and related accrued interest due under the bridge financing agreement. Since repayment in August 2004, no amounts have been outstanding on this bridge financing agreement and no new agreements have been established to continue the bridge financing arrangement.

Cash Flows. Our primary sources of cash have been cash flows from operations and equity offerings. During the three years ended December 31, 2004, we generated $7,572,898 from operating activities, financed $14,230,863 through proceeds from the sale of stock and warrants, and $400,000 from debt obligations owed to two officers, for a total of $22,203,761. We primarily used this cash generation to fund our capital expenditures aggregating $31,385,738 over the three years. At December 31, 2004, we had $1,253,969 of cash and $772,154 of working capital compared to December 31, 2003 when our cash position was $1,076,676 and working capital was $1,268,888.

We continually evaluate our capital needs and compare them to our capital resources. Our budgeted capital expenditures for 2005 are approximately $15,000,000 for development of our current properties. We expect to fund these expenditures as well as any future property acquisitions from cash on hand, internally generated cash flow during the year 2005, proceeds from future equity transactions and from borrowings under our credit facility, if required. The level of capital expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among others.

Schedule of Contractual Obligations. The following table summarizes our future estimated principal and minimum debt and lease payments for periods subsequent to December 31, 2004.

Year	**Long-Term Debt**	**Lease Obligation**	**Total Cash Obligation**
2005	$ -	$ 24,400	$ 24,400
2006	400,000	-	400,000
2007	10,000,000	-	10,000,000
Total	$ 10,400,000	$ 24,400	$ 10,424,400

Off-Balance Sheet Financing Arrangements

As of December 31, 2004 we had no off-balance sheet financing arrangements.

New Accounting Policies

Effective January 1, 2003, we adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. In regards to us, this statement applies directly to the plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 8.08%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, we recorded an increase to our discounted abandonment liability of $236,718, increased property and equipment cost by $217,878 and recognized a one-time cumulative effect charge of $11,813 (net of a deferred tax benefit of $7,027).

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities*. This interpretation establishes the requirement for a primary beneficiary to consolidate certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. We do not have an interest in a variable interest entity and the adoption of the statement did not have an impact on our financial statements.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement was effective for us in July 2003. The statement requires financial instruments to be classified as liabilities if the financial instruments are issued in the form of shares that are mandatorily redeemable or embody an obligation to repurchase equity shares. We issued a put option in exchange for oil and gas property interests in December 2004. The put option was originally classified as a liability; therefore, the adoption of the statement did not have an impact on our financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our financial statements. The preparation of these statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. Our significant accounting policies are detailed in Note 1 to our financial statements included in this Annual Report. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Revenue Recognition. We predominantly derive our revenue from the sale of produced crude oil and natural gas. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received; however, differences have been insignificant.

Full Cost Method of Accounting. We account for our oil and natural gas operations using the full cost method of accounting. Under this method, all costs associated with property acquisition, exploration and development of oil and gas reserves are capitalized. Costs capitalized include acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and cost of drilling and equipping productive and non-productive wells. Drilling costs include directly related overhead costs. All of our properties are located within the continental United States.

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this Annual Report are prepared in accordance with guidelines established by the SEC and FASB. The accuracy of our reserve estimates is a function of:

- the quality and quantity of available date;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the persons preparing the estimates.

Our proved reserve information included in this Annual Report is based on estimates prepared by Lee Keeling and Associates, Inc., independent petroleum engineers. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We continually make revisions to reserve estimates throughout the year as additional properties are acquired. We make changes to depletion rates and impairment calculations in the same period that changes to the reserve estimates are made.

All capitalized costs of oil and gas properties, including estimated future costs to develop proved reserves and estimated future costs of site restoration, are amortized on the unit-of-production method using estimates of proved reserves as determined by independent engineers. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined.

Impairment of Oil and Natural Gas Properties. We review the value of our oil and natural gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. We provide for impairments on undeveloped property when we determine that the property will not be developed or a permanent impairment in value has occurred. Impairments of proved producing properties are calculated by comparing future net undiscounted cash flows on a field-by-field basis using escalated prices to the net recorded book cost at the end of each period. If the net capitalized cost exceeds net future cash flows, the cost of the property is written down to fair value, which is determined using net discounted future cash flows from the producing property. Different pricing assumptions or discount rates could result in a different calculated impairment. We have never recorded any property impairments.

Income Taxes. We provide for income taxes in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. Deferred income taxes are provided for the difference between the tax basis of assets and liabilities and the carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is settled. Since our tax returns are filed after the financial statements are prepared, estimates are required in valuing tax assets and liabilities. We record adjustments to actual in the period we file our tax returns.

Effects of Inflation and Pricing

While we did not experience any significant increased costs during 2003 due to increased demand for oil field products and services, this trend did not continue in 2004. The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs, and this proved to be the case in 2004 as oil and gas prices rose significantly. Costs for oilfield services and materials increased during 2004 due to higher demand as a result of the higher oil and gas prices. Material changes in prices impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans and value of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. We anticipate the increased business costs will continue while the commodity prices for oil and natural gas, and the demand for services related to production and exploration, both remain high (from an historical context) in the near term.

Quantitative and Qualitative Disclosure About Market Risk

Commodity Price Risk

We have not historically entered into derivative contracts to manage our exposure to oil and natural gas price volatility. Normal hedging arrangements have the effect of locking in for specified periods the prices we would receive for the volumes and commodity to which the hedge relates. Consequently, while hedges are designed to decrease exposure to price decreases, they also have the effect of limiting the benefit of price increases.

Interest Rate Risk

Our current credit facility has a floating interest rate. Therefore, as a result of our draws on this credit facility, interest rate changes will impact future results of operations and cash flows.

Item 7: **Financial Statements**

The financial statements and supplementary data required by this item are included at page 40.

Item 8: **Changes in and Disagreements with Accountants And Accounting and Financial Disclosure**

None.

Item 8A: **Controls and Procedures**

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. As of the end of the fiscal year ended December 31, 2004, our chief executive officer and chief financial officer evaluated the effectiveness of our disclosure controls and procedures. Based upon their evaluation of those controls and procedures, the chief executive officer and the principal financial officer of the Company concluded that as of the end of such period our disclosure controls and procedures are effective in alerting them to material information that is required to be included in the reports we file or submit under the Securities Exchange Act of 1934.

We made no change in our internal control over financial reporting during our fiscal year ended December 31, 2004 that has materially affected, or is reasonably likely to materially affect our internal control over financial reporting.

Item 8B: **Other Information**

None

PART III

Item 9: **Directors and Executive Officers**

Executive Officers and Directors

The following table sets forth information regarding our executive officers, certain other officers and directors as of December 31, 2004:

Name	Age	Position
Lloyd T. Rochford	58	President and Chief Executive Officer and Director
Stanley M. McCabe	72	Chairman of the Board of Directors, Secretary and Treasurer
William R. Broaddrick	27	Vice President and Chief Financial Officer
Charles M. Crawford	52	Director
Chris V. Kemendo, Jr.	83	Director
Clayton E. Woodrum	64	Director

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Each of the directors identified above were elected for a term of one year (or until their successors are elected and qualified) at our annual meeting of shareholders in December 2004.

Messrs. Rochford, McCabe and Crawford have served as directors since our inception in August 2000. Mr. Kemendo was first elected to the Board of Directors in February 2003 and Mr. Woodrum was initially appointed in August 2003 by the Board of Directors to fill a vacancy created upon the resignation of a director.

The following biographies describe the business experience of our executive officers and directors:

Lloyd T. Rochford President, Chief Executive Officer and Director.

Mr. Rochford, 58, has been active as an individual consultant and entrepreneur in the oil and gas industry since 1973. In this capacity, he has primarily been engaged in the organization and funding of private oil and gas drilling and completion projects and ventures within the mid-continent region of the United States. In 1990 Mr. Rochford was co-founder, director and CEO of a public company known as Magnum Petroleum, Inc. (Magnum) which is listed on the New York Stock Exchange. Subsequently, Magnum acquired Hunter Resources, Inc. in August, 1995. Mr. Rochford served as Chairman of the Board of the combined companies from August, 1995 to June, 1997. Since July, 1997, Mr. Rochford has primarily devoted his time and efforts to individual oil and gas acquisition and development prior to his commitment to participate in Arena Resources. In 1982, Mr. Rochford was co-founder of Dana Niguel Bank, a publicly held California bank operation and served as a director until 1994. Mr. Rochford attended various college level courses in business from 1967 to 1970 in California.

Stanley M. McCabe Chairman of the Board of Directors, Secretary and Treasurer.

Mr. McCabe, 72, served from 1979 to 1989, as Chairman and CEO of Stanton Energy, Inc., a Tulsa, Oklahoma natural resource company specializing in contract drilling and operation of oil and gas wells. In 1990, Mr. McCabe also became a co-founder and subsequently an officer and director of Magnum Petroleum, Inc., along with Mr. Rochford as previously discussed. Subsequently, Mr. McCabe served as a director of Magnum Hunter Resources, Inc., through December, 1996. Since January, 1997, Mr. McCabe has been involved as an independent investor and developer of oil and natural gas properties. Mr. McCabe attended college courses at the University of Maryland, primarily in business, in 1961 and 1962.

William R. Broaddrick Vice President and Chief Financial Officer.

Mr. Broaddrick, 27, was employed from 1997 to 2000 with Amoco Production Company, performing lease revenue accounting and state production tax regulatory reporting functions. During 2000, Mr. Broaddrick was employed by Duke Energy Field Services, LLC performing state production tax functions. In September 2001, Mr. Broaddrick joined us as chief accountant, and effective February 1, 2002, assumed responsibilities as Vice President and Chief Financial Officer.

Mr. Broaddrick received a Bachelor s Degree in Accounting from Langston University, through Oklahoma State University Tulsa, in 1999. Mr. Broaddrick is a Certified Public Accountant.

Charles M. Crawford Director

Mr. Crawford, 52, has for the past twenty-nine years served as an independent oil and gas exploration consultant to various private and public oil and gas companies within the United States. He has acted as a consultant to such firms as Texaco, Inc, Phillips Petroleum Company, Mid-Continent Energy Corp. as well as other regional and national companies primarily acting in the mid-continent area. Mr. Crawford received a Masters Degree in geology from Miami University of Ohio, in 1976. Mr. Crawford will serve the company on an as needed basis as an outside director.

Chris V. Kemendo, Jr. Director.

Mr. Kemendo, 83, has from 1989 to present acted as an independent financial business and accounting consultant to various clients. Mr. Kemendo is currently the Chairman of our audit committee and compensation committee. Mr. Kemendo has 56 years of accounting experience. Mr. Kemendo graduated from the University of Oklahoma and subsequently became a Certified Public Accountant. From 1947 to 1957, Mr. Kemendo was a manager of Arthur Young & Company, in charge of audit departments in Kansas City, Missouri, Wichita, Kansas and Caracas, Venezuela. From 1957 to 1961, Mr. Kemendo served as Controller and CFO for Rio Arriba Drilling Company. From 1961 to 1967, he was a partner of Fox & Company, Certified Public Accountants. From 1967 to 1973, he served as Executive Vice-President and CFO of LaBarge, Inc. From 1973 to 1979, Mr. Kemendo was a partner at Daniel and Howard, Inc. From 1979 to 1982, he again served as a partner at Fox & Company (now Grant Thornton, LLP). From 1982 to 1988, Mr. Kemendo was Executive Vice-President and Director at Fitzgerald, DeArman & Roberts, Inc.

Clayton E. Woodrum Director.

Mr. Woodrum, 64, is a Certified Public Accountant and has, from 1984 to present, been a principal shareholder in the accounting firm of Woodrum, Kemendo & Cuite, P.C., and has been an owner of Computer Data Litigation Services, LLC and First Capital Management, LLC. From 1965 to 1975, Mr. Woodrum was employed by Peat, Marwick, Mitchell & Co., serving as partner in charge of the tax department during the final two years. From 1975 to 1980 he served as CFO for BancOklahoma Corp. and Bank of Oklahoma. From 1980 to 1984 Mr. Woodrum served as a partner in charge of the tax department at Peat, Marwick, Mitchell & Co. One of Mr. Woodrum s partners at Woodrum, Kemendo & Cuite, P.C., Ben Kemendo, is the son of Chris Kemendo, Jr.

Our executive officers are elected by, and serve at the pleasure of, our board of directors. Our directors serve terms of one year each, with the current directors serving until the 2005 annual meeting of stockholders, and in each case until their respective successors are duly elected and qualified.

None of our directors currently serves as a director of any other company which is required to file periodic reports under the Securities Exchange Act of 1934.

Board Committees

Our board of directors has established an audit committee, whose principal functions are to assist the board in monitoring the integrity of our financial statements, the independent auditor s qualifications and independence, the performance of our independent auditors and our compliance with legal and regulatory requirements. The audit committee has the sole authority to retain and terminate our independent auditors and to approve the compensation paid to our independent auditors. The audit committee is also responsible for overseeing our internal audit function. The audit committee is comprised of two independent directors, consisting of Messrs. Kemendo and Woodrum, with Mr. Kemendo acting as the chairman. Our board of directors has determined that each member of the audit committee qualifies as an audit committee financial expert under the rules of the SEC adopted pursuant to requirements of the Sarbanes-Oxley Act of 2002 (see the biographical information for each of Messrs. Kemendo and Woodrum, infra, in this discussion of Directors and Executive Officers.) Each of Messrs. Kemendo and Woodrum further qualifies as independent in accordance with the applicable regulations adopted by the SEC and American Stock Exchange.

Our board of directors has established a compensation committee, whose principal function is to make recommendations regarding the compensation of the Company s officers. In accordance with the rules of the American Stock Exchange (on which our shares are listed), the compensation of our chief executive officer is recommended to the Board (in a proceeding in which the chief executive officer does not participate) by the compensation committee. The compensation committee is comprised of two independent directors, consisting of Messrs. Kemendo and Woodrum, with Mr. Kemendo acting as the chairman. Compensation for all other officers is also recommended to the Board for determination, by the compensation committee.

We currently do not have a nominating committee. Instead, in accordance with the rules of the American Stock Exchange, the independent directors (currently, Messrs. Crawford, Kemendo and Woodrum) fulfill the role of a nominating committee. Since our inception in 2000, we have had only six directors, five of whom continue to serve at this time. On the only occasion when a vacancy occurred (following a resignation), the new director was unanimously approved by the remaining directors. Therefore, the Board has not felt it necessary to have a standing nominating committee to deal with its infrequent changes in membership. If and when future vacancies occur, the Board would consider director nominees recommended by shareholders, as well as director nominees recommended by a majority of the directors who are then independent. The board does not have a formal policy regarding the consideration of, procedures to be followed by, minimum requirements of or process for identifying or evaluation nominees recommended by security holders.

Our board may establish other committees from time to time to facilitate our management.

Director Compensation

All outside directors are currently compensated with a stipend of $500 per month plus $500 for each directors meeting attended. No director receives a salary as a director.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of our board of directors or compensation committee.

Section 16(a) Beneficial Ownership Reporting Compliance

Based solely upon a review of Forms 4 furnished to us during our most recent fiscal year, we know of no director, officer or beneficial owner of more than ten percent of our common stock who failed to file on a timely basis reports of beneficial ownership of the our common stock as required by Section 16(a) of the Securities Exchange Act of 1934, as amended.

Code of Ethics

We have adopted a code of ethics that applies to our principal executive officer, principal financial officer and principal accounting officer or persons performing similar functions (as well as its other employees and directors). The Company undertakes to provide any person without charge, upon request, a copy of such code of ethics. Requests may be directed to Arena Resources, Inc., 4920 S. Lewis Ave., Suite 107, Tulsa, Oklahoma 74105, attention William R. Broaddrick, or by calling (918) 747-6060.

Item 10: Executive Compensation

The following table sets forth information concerning the compensation paid by us for the three most recent fiscal years to our chief executive officer and our other two executive officers.

Summary Compensation Table

		Annual Compensation		Long-Term Compensation Awards
Name and Principal Position	**Year**	**Salary[1]**	**Bonus**	**Securities Underlying Options[2]**
Lloyd T. Rochford				
President and Chief Executive Officer	2002	$ 36,000	$ -	$ -
	2003	$ 36,000	$ -	$229,742
	2004	$ 36,000	$ -	$ -
Stanley M. McCabe				
Chairman of the Board	2002	$ 36,000	$ -	$ -
	2003	$ 36,000	$ -	$229,742
	2004	$ 36,000	$ -	$ -
William R. Broaddrick				
Vice President, Chief Financial Officer	2002	$ 45,000	$ 6,000	$ -
	2003	$ 47,927	$ -	$459,484
	2004	$ 51,500	$ 4,167	$ -

(1) Mr. Broaddrick s salary for 2003 reflects a raise that occurred in mid-year to increase his annual salary to $50,000. Mr. Broaddrick s salary for 2004 reflects a raise that occurred during the year to increase his annual salary to $54,000. There are no current plans to change any officers salary from their level at December 31, 2004.

(2) The fair value of the options is estimated on the dates granted using the Black-Scholes option pricing model with the following weighted average assumptions: dividend yield of 0%; expected volatility of 36.2%; risk-free interest rate of 2.9% and expected lives of 5.0 years. The weighted average remaining contractual life of the options at December 31, 2004 was 3.8 years.

Employee Benefit Plans

Equity Incentive Plan. In March 2003, our board of directors adopted an executive stock option plan which was subsequently approved by our shareholders at our annual meeting in July 2003 and further amended by our shareholders at our annual meeting in December 2004. The executive stock option plan is intended to promote continuity of management and to provide increased incentive and personal interest in our welfare by those key employees who are primarily responsible for shaping and carrying out our long-range plans and securing our continued growth and financial success. In addition, by encouraging stock ownership by directors who are not our employees, the executive stock option plan is intended to attract and retain qualified directors.

The plan is administered by Messrs. Rochford and McCabe, and they have the authority to select the key employees and non-employee directors to be participants in the plan, to determine the awards to be granted to participants and the number of shares covered by such awards, to set the terms and conditions of such awards and to establish, amend or waive rules for the administration of the plan.

Any of our key employees, including any of our executive officers or directors, is eligible to be granted awards by plan administrators. The plan authorizes the grant of stock options to key employees, all of which have been non-qualified stock options. Our non-employee directors are only eligible to be granted non-qualified stock options under the plan.

The plan provides that up to a total of 1,500,000 shares of common stock, subject to adjustment to reflect stock dividends and other capital changes, are available for granting of awards under the executive stock option plan. 1,000,000 of the shares available for grant under the plan have been reserved for issuance pursuant to options granted during 2003. No options to acquire shares were granted under the plan in 2004.

The following table provides information regarding option exercises and fiscal year-end option values calculated by determining the difference between the closing price of our common stock at December 31, 2004 and the exercise price of the options.

Name	**Shares Acquired on Exercise**	**Value Realized ($)**	**Number of Unexercised Securities Underlying Options/SARs at FY-End (#) Exercisable Unexercisable**	**Value of Unexercisable In-The-Money Options/SARs at FY-End ($) Exercisable/ Unexercisable**
Lloyd T. Rochford	0	0	25,000/100,000	$120,000/$480,000
Stanley M. McCabe	0	0	25,000/100,000	$120,000/$480,000
William R. Broaddrick	0	0	50,000/200,000	$240,000/$960,000
Charles M. Crawford	0	0	10,000/40,000	$48,000/$192,000
Chris V. Kemendo, Jr.	0	0	10,000/40,000	$48,000/$192,000
Clayton E. Woodrum	0	0	10,000/40,000	$37,000/$148,000
Phillip W. Terry	0	0	50,000/200,000	$240,000/$960,000
Raymond H. Estep	0	0	20,000/80,000	$96,000/$384,000

The following table sets forth information concerning our executive stock option plan as of December 31, 2004.

	Number of securities to be issued upon exercise of outstanding options	**Weighted-average exercise price of outstanding options**	**Number of securities remaining available for future issuance under compensation plans (excluding securities in column (a))**
	(a)	(b)	(c)
Equity compensation plans approved by security holders	1,000,000	3.76	500,000
Equity compensation plans not approved by security holders	-	-	-
Total	1,000,000	3.76	500,000

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Item 11: **Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters**

The following table sets forth, as March 10, 2005, information regarding the beneficial ownership of our common stock: (i) by each of our directors and executive officers; (ii) by all directors and executive officers as a group; and (iii) by all persons known to us to own 5% or more of our outstanding shares of common stock. The mailing address for each of the persons indicated is our corporate headquarters.

Beneficial ownership is determined under the rules of the Securities and Exchange Commission. In general, these rules attribute beneficial ownership of securities to persons who possess sole or shared voting power and/or investment power with respect to those securities and includes, among other things, securities that an individual has the right to acquire within 60 days. Unless otherwise indicated, the stockholders identified in the following table have sole voting and investment power with respect to all shares shown as beneficially owned by them.

	Shares of Common Stock Beneficially Owned	
Name	**Number**	**Percent**
Lloyd T. Rochford	1,262,600 (1)	12%
Stanley M. McCabe	1,263,000 (2)	12%
William R. Broaddrick	104,500 (3)	1%
Charles M. Crawford	20,000 (4)	*
Chris V. Kemendo, Jr	20,100 (5)	*
Clayton E. Woodrum	10,000 (6)	*
All directors and executive officers	2,680,200 (7)	26%

(1) Includes 25,000 shares issuable upon the exercise of stock options that are currently exercisable and 25,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(2) Includes 25,000 shares issuable upon the exercise of stock options that are currently exercisable and 25,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(3) Includes 50,000 shares issuable upon the exercise of stock options that are currently exercisable and 50,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(4) Includes 10,000 shares issuable upon the exercise of stock options that are currently exercisable and 10,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(5) Includes 10,000 shares issuable upon the exercise of stock options that are currently exercisable and 10,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(6) Includes 10,000 shares issuable upon the exercise of stock options that are currently exercisable.
(7) Includes 130,000 shares issuable upon the exercise of stock options that are currently exercisable and 120,000 shares issuable upon the exercise of stock options that are exercisable within 60 days by all executive officers and directors.
* Represents beneficial ownership of less than 1%

Percentage ownership calculations for any stockholder listed above are based on 10,194,304 shares of our common stock outstanding as of March 10, 2005.

Item 12: Certain Relationships and Related Transactions

The initial capital assets that were contributed to us were provided by Messrs. Rochford and McCabe. In contributing these assets to us in September 2000, no independent determination was made regarding the value of the oil and gas properties and related interests contributed in exchange for stock. In exchange for the initial 1,300,000 shares of common stock issued to each of Messrs. Rochford and McCabe, each contributed $33,695 in cash and a carried working interest obligation with future development costs estimated by an independent oil and gas engineer of approximately $134,000. Of the cash contributed, $61,174 was used to acquire our three initial leases. The estimated future development costs were accounted for as a receivable from Messrs. Rochford and McCabe. Total actual costs incurred by them in relation to the carried working interest were $121,274. The difference of $12,726 was charged against additional paid in capital.

In July 2002, we borrowed $200,000 from each of Messrs. Rochford and McCabe, which debts are evidenced by notes payable which mature on January 1, 2006. The notes bear interest at a rate of 10% per annum, and are secured by our assets (although such notes are subordinate to our credit facility with our primary commercial lender).

In 2001 and 2002 we acquired certain lease interests and had other business dealings with Petro Consultants, Inc. One of the principals of Petro Consultants, Inc., Mr. Robert J. Morley, was appointed our Vice President of Investor Relations in July 2002 and served as a member of the Board of Directors from February 2003, until his resignation of all positions as an officer and director in August 2003. Therefore, any transactions involving Petro Consultant between July 2002 and August 2003 could be deemed to have been entered into with an affiliate. Because we anticipated that we may continue to transact business with Petro Consultants, to avoid future issues that might arise due to such affiliation, Mr. Morley resigned his position as an officer and member of our board and forfeited all stock options (none of which had vested) which he had been granted by reason of his position as a board member.

Item 13: Exhibits

Exhibit Index:

3.1 Articles of Incorporation of Arena Resources, Inc. (i)

3.2 By-Laws of Arena Resources, Inc. (i)

10.1 Business Loan Agreement, dated as of April 14, 2004, among Arena Resources, Inc. and MidFirst Bank, N.A. (ii)

10.2 Business Loan Agreement, dated as of May 7, 2004, among Arena Resources, Inc. and MidFirst Bank, N.A. (ii)

10.3 Business Loan Agreement, dated as of November 16, 2004, among Arena Resources, Inc. and MidFirst Bank, N.A. (iii)

10.4 East Hobbs Purchase and Sales Agreement Dated April 22, 2004 (ii)

10.5 Fuhrman-Mascho Purchase and Sales Agreements Dated December 1, 2004 (iii)

23 Consent of Lee Keeling and Associates, Inc., Independent Petroleum Engineers

31.1 Certification of CEO

31.2 Certification of CFO

32.1 Section 1350 Certification - CEO

32.2 Section 1350 Certification - CFO

(i) Incorporated herein by reference to the exhibits to Arena Resources, Inc. s Form SB-1 filed January 2, 2001 (SEC File No. 333-46164).

(ii) Incorporated herein by reference to the exhibits to Arena Resources, Inc. s From 8-K filed May 18, 2004.

(iii) Incorporated herein by reference to the exhibits to Arena Resources Form 10-KSB filed March 17, 2005.

Item 14: Principal Accountant Fees and Services

The firm of Hansen, Barnett & Maxwell, (HBM) has served as the Company s independent auditors since 2000. The Board of Directors selected HBM as the independent auditors of the Company for the fiscal year ending December 31, 2004, and the Audit Committee has selected HBM to serve in the same capacity for the fiscal year ending December 31, 2005. The Audit Committee has adopted a policy that requires advance approval of all audit, audit-related, tax services and other services performed by the independent auditor.

Fees and Independence

Audit Fees. HBM billed the Company an aggregate of $37,000 and $25,521 for professional services rendered for the audit of the Company s financial statements for the years ended December 31, 2004 and 2003, respectively, and its reviews of the Company s financial statements included in its Form 10-QSB s for the first three quarters of 2004 and 2003.

Audit Related Fees. In 2004, HBM was paid $78,998 for its services in connection with the review of the Company s registration statement on Form SB-2 (which was filed with the SEC in 2004) and for the audit of the Fuhrman-Mascho property acquisition, and which are not included in the audit fees identified above).

Tax Fees. HBM billed the Company an aggregate of $3,000 and $750 for professional services rendered for tax compliance, tax advice and tax planning for the years ended December 31, 2004 and 2003.

All Other Fees. No other fees were billed by HBM to the Company during 2004 or 2003.

The Audit Committee of the Board of Directors has determined that the provision of services by HBM described above is compatible with maintaining HBM s independence as the Company s principal accountant.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on behalf by the undersigned, thereunto duly authorized.

ARENA RESOURCES, INC.

By: /s/ Lloyd T. Rochford

Mr. Lloyd T. Rochford, President,
Chief Executive Officer

Date: October 14, 2005

By: /s/ Stanley McCabe

Mr. Stanley McCabe
Treasurer, Secretary

Date: October 14, 2005

By: /s/ William R. Broaddrick

Mr. William R. Broaddrick
Chief Financial Officer

Date: October 14, 2005

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

By: /s/ Lloyd T. Rochford

Mr. Lloyd T. Rochford, President,
Chief Executive Officer

Date: October 14, 2005

By: /s/ Stanley McCabe

Mr. Stanley McCabe
Treasurer, Secretary

Date: October 14, 2005

By: /s/ Charles Crawford

Mr. Charles Crawford
Director

Date: October 14, 2005

By: /s/ Chris V. Kemendo, Jr.

Mr. Chris V. Kemendo, Jr.
Director

Date: October 14, 2005

By: /s/ Clayton E. Woodrum

Mr. Clayton E. Woodrum
Director

Date: October 14, 2005

ARENA RESOURCES, INC.

INDEX TO FINANCIAL STATEMENTS

HANSEN, BARNETT & MAXWELL
A Professional Corporation
CERTIFIED PUBLIC ACCOUNTANT
5 Triad Center, Suite 750
Salt Lake City, UT 84180-1128
Phone: (801) 532-2200
Fax: (801) 532-7944
www.hbmcpas.com

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and the Stockholders
Arena Resources, Inc.

We have audited the accompanying balance sheets of Arena Resources, Inc. as of December 31, 2004 and 2003, and the related statements of operations, stockholders equity, and cash flows for the years then ended. 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 audits 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, 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 financial position of Arena Resources, Inc. as of December 31, 2004 and 2003, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 5 to the financial statements, the Company changed its method of recognizing asset retirement obligations in 2003.

HANSEN, BARNETT & MAXWELL

Salt Lake City, Utah
January 14, 2005

ARENA RESOURCES, INC.
BALANCE SHEETS

December 31,	2004	2003
ASSETS		
Current Assets		
Cash	$ 1,253,969	$ 1,076,676
Account receivable	1,149,513	388,910
Joint interest billing receivable	61,805	-
Short-term investments	-	25,234
Prepaid expenses	33,136	28,935
Total Current Assets	2,498,423	1,519,755
Property and Equipment, Using Full Cost Accounting		
Oil and gas properties subject to amortization	34,421,920	8,463,400
Drilling advances	900,000	351,000
Equipment	26,687	48,480
Office equipment	60,401	18,978
Total Property and Equipment	35,409,008	8,881,858
Less: Accumulated depreciation and amortization	(1,565,124)	(559,229)
Net Property and Equipment	33,843,884	8,322,629
Deferred Offering Costs	-	130,872
Total Assets	$ 36,342,307	$ 9,973,256
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 1,805,865	$ 229,522
Accrued liabilities	34,800	18,440
Put option	-	2,905
Total Current Liabilities	1,840,665	250,867
Long-Term Liabilities		
Notes payable	10,000,000	-
Notes payable to related parties	400,000	400,000
Put option	95,033	-
Asset retirement liability	1,267,993	607,200
Deferred income taxes	2,129,993	656,759
Total Long-Term Liabilities	13,893,019	1,663,959
Stockholders' Equity		
Preferred stock - $0.001 par value; 10,000,000 shares authorized; no shares issued or outstanding	-	-
Common stock - $0.001 par value; 100,000,000 shares authorized; 9,132,910 shares and 7,162,097 shares outstanding, respectively	9,133	7,162
Additional paid-in capital	15,223,135	6,994,925
Options and warrants outstanding	2,553,159	813,164
Retained earnings	2,823,196	243,179
Total Stockholders' Equity	20,608,623	8,058,430

Total Liabilities and Stockholders' Equity	$ 36,342,307	$ 9,973,256

The accompanying notes are an integral part of these financial statements.

ARENA RESOURCES, INC.
STATEMENTS OF OPERATIONS

For the Years Ended December 31,	2004	2003
Oil and Gas Revenues	$ 8,482,130	$ 3,665,477
Costs and Operating Expenses		
Oil and gas production costs	1,975,835	1,149,136
Oil and gas production taxes	629,703	269,563
Depreciation, depletion and amortization	1,011,602	360,282
General and administrative expense	670,325	557,576
Total Costs and Operating Expenses	4,287,465	2,336,557
Other Income (Expense)		
Gain from change in fair value of put options	68,251	47,699
Accretion expense	(53,729)	(32,212)
Interest expense	(155,936)	(38,798)
Net Other Income (Expense)	(141,414)	(23,311)
Income Before Provision for Income Taxes and Cumulative Effect of Change in Accounting Principle	4,053,251	1,305,609
Provision for Deferred Income Taxes	(1,473,234)	(484,298)
Income Before Cumulative Effect of Change in Accounting Principle	2,580,017	821,311
Cumulative Effect of Change in Accounting Principle	-	(11,813)
Net Income	$ 2,580,017	$ 809,498
Basic Earnings Per Share		
Before cumulative effect of change in accounting principle	$ 0.33	$ 0.12
Net Income	0.33	0.12
Diluted Earnings Per Share		
Before cumulative effect of change in accounting principle	$ 0.30	$ 0.11
Net Income	0.30	0.11

The accompanying notes are an integral part of these financial statements.

ARENA RESOURCES, INC.
STATEMENTS OF STOCKHOLDERS EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2003 AND 2004

	Common Stock					
	Shares	Amount	Additional Paid-In Capital	Options and Warrants Outstanding	Retained Earnings	Total Stockholders' Equity
Balance December 31, 2002	6,282,056	$ 6,282	$ 5,287,189	$ 382,040	$ (566,319)	$ 5,109,192
Issuance for cash	790,294	790	1,274,256	436,154	-	1,711,200
Issuance of warrants as consulting fee for 2002 offering	-	-	(15,922)	15,922	-	-
Cancellation of shares for extension of lock up	(500)	(0)	0	-	-	-
Issuance of common stock for services	13,847	14	75,026	-	-	75,040
Warrants exercised	19,400	19	54,883	(20,952)	-	33,950
Issuance of common stock in property acquisitions	57,000	57	319,493	-	-	319,550
Net Income	-	-	-	-	809,498	809,498
Balance December 31, 2003	7,162,097	7,162	6,994,925	813,164	243,179	8,058,430
Warrants exercised	78,300	78	395,843	(41,796)	-	354,125
Issuance for cash	1,667,500	1,668	6,469,225	1,781,791	-	8,252,684
Issuance of common stock in property acquisitions, net of call option received	225,013	225	1,363,142	-	-	1,363,367
Net Income	-	-	-	-	2,580,017	2,580,017
Balance December 31, 2004	9,132,910	$ 9,133	$ 15,223,135	$ 2,553,159	$ 2,823,196	$ 20,608,623

The accompanying notes are an integral part of these financial statements.

ARENA RESOURCES, INC.
STATEMENTS OF CASH FLOWS

For the Years Ended December 31	2004	2003
Cash Flows From Operating Activities		
Net income	$ 2,580,017	$ 809,498
Adjustments to reconcile net income to net cash provided by operating activities:		
Shares issued for services	-	75,040
Depreciation, depletion and amortization	1,011,602	360,282
Gain from change in fair value of put option	(68,251)	(47,699)
Cumulative effect of change in accounting principle	-	11,813
Loss on sale of equipment	5,586	-
Accretion of discounted asset retirement liability and note payable	83,730	32,212
Changes in assets and liabilities:		
Accounts receivable	(656,864)	(119,474)
Prepaid expenses	(4,201)	(27,807)
Accounts payable and accrued liabilities	1,570,831	74,787
Deferred income taxes	1,473,234	484,298
Net Cash Provided by Operating Activities	5,995,684	1,652,950
Cash Flows from Investing Activities		
Proceeds from sale of equipment	10,500	-
Cash payments on purchase of East Hobbs property	(1,028,000)	-
Cash payments on purchase of Furhman-Mascho property	(711,802)	-
Purchase and development of oil and gas properties	(4,802,141)	(3,050,558)
Purchase of property, plant & equipment	-	(26,686)
Maturity of long-term investment	25,234	51,268
Purchase of office equipment	(41,423)	(4,306)
Net Cash Used in Investing Activities	(6,547,632)	(3,030,282)
Cash Flows From Financing Activities		
Proceeds from issuance of common stock and warrants, net of offering costs	8,383,557	1,580,328
Proceeds from exercise of warrants	354,124	33,950
Issuance of note payable	2,000,000	-
Payment of notes payable	(10,008,440)	-
Collection of common stock subscription receivable	-	157,500
Payment of accrued dividends to preferred stockholders	-	