# FORM 10-K

Annual report pursuant to section 13 and 15(d)

Filing Date: **2004-05-18** | Period of Report: **2003-12-31**
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## FILER

**SOUTHWEST DEVELOPMENTAL DRILLING FUND 92-A LP**
CIK:**871332**| IRS No.: **752387816** | State of Incorp.:**DE** | Fiscal Year End: **1231**
Type: **10-K** | Act: **34** | File No.: **000-21132** | Film No.: **04814852**
SIC: **1381** Drilling oil & gas wells

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FORM 10-K
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

(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, 2003

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 33-38511

Southwest Developmental Drilling Fund 92-A, L.P.
(Exact name of registrant as specified in its limited partnership agreement)

| | |
|---|---|
| Delaware | 75-2387816 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| 407 N. Big Spring, Suite 300, Midland, Texas | 79701 |
| (Address of principal executive office) | (Zip Code) |

Registrant's telephone number, including area code (432) 686-9927

Securities registered pursuant to Section 12(b) of the Act:

None

Securities registered pursuant to Section 12(g) of the Act:

limited and general partner interests

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes No X

The registrant's outstanding securities consist of Units of limited partnership interests for which there exists no established public market from which to base a calculation of Aggregate market value.

The total number of pages contained in this report is 47. The exhibits begin on page 44.

Table of Contents

Glossary of Oil and Gas Terms

The following are abbreviations and definitions of terms commonly used in the oil and gas industry that are used in this filing. All volumes of natural gas referred to herein are stated at the legal pressure base to the state or area where the reserves exit and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Bbl. One stock tank barrel, or 42 United States gallons liquid volume.

Developmental well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Exploratory well. A well drilled to find and produce oil or gas in an unproved area to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Farm-out arrangement. An agreement whereby the owner of a leasehold or working interest agrees to assign his interest in certain specific acreage to an assignee, retaining some interest, such as an overriding royalty interest, subject to the drilling of one (1) or more wells or other specified performance by the assignee.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Mcf. One thousand cubic feet.

Oil. Crude oil, condensate and natural gas liquids.

Overriding royalty interest. Interests that are carved out of a working interest, and their duration is limited by the term of the lease under which they are created.

Present value and PV-10 Value. When used with respect to oil and natural gas reserves, the estimated future net revenue to be generated from the production of proved reserves, determined in all material respects in accordance with the rules and regulations of the SEC (generally using prices and costs in effect as of the date indicated) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

Proved Area. The part of a property to which proved reserves have been specifically attributed.

Proved developed oil and gas reserves. Reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved properties. Properties with proved reserves.

Proved oil and gas reserves. The estimated quantities of crude oil, natural gas, and natural gas liquids with geological and engineering data that demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e.e., prices and costs as of the date the estimate is made.

Proved undeveloped reserves. Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty interest. An interest in an oil and natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

## Part I

### Item 1. Business

General

Southwest Developmental Drilling Fund 92-A, L.P. (the "Partnership" or "Registrant") was organized as a Delaware limited partnership on May 5, 1992. The offering of limited and general partner interests began August 11, 1992 as part of a shelf offering registered under the name Southwest Developmental Drilling Program 1991-92. Minimum capital requirements for the Partnership were met on December 28, 1992, with the offering of limited and general partner interests concluding December 31, 1992, with total investor partner contributions of $1,407,000. The Managing General Partner made a contribution to the capital of the Partnership at the conclusion of the offering period in an amount equal to 1% of its net capital contributions. The Managing General Partner contribution was $12,030, for total capital contributions of $1,419,030. The Partnership has no subsidiaries.

The Partnership has expended its capital and acquired leasehold interests and completed drilling operations. The Partnership has produced and marketed the crude oil and natural gas from such properties.

The principal executive offices of the Partnership are located at 407 N. Big Spring, Suite 300, Midland, Texas, 79701. The Managing General Partner of the Partnership, Southwest Royalties, Inc. (the "Managing General Partner") and its staff of 81 individuals, together with certain independent consultants used on an "as needed" basis, perform various services on behalf of the Partnership, including the selection of leasehold interests upon which drilling would be performed, and the marketing of future anticipated production from such properties. The Partnership has no employees.

Introductory Note - Statement of Financial Accounting Standard No. 143

The Partnership implemented SFAS No. 143 effective January 1, 2003 (See Note 3 to the Partnership's financial statements).

Introductory Note - Depletion Method

During 2002, the Partnership changed its method of providing for depletion from the units-of-revenue method to the units-of-production method as described in Note 4 to the Partnership's financial statements. This change in depletion method was applied as a cumulative effect of a change in accounting principle effective as of January 1, 2002.

## Principal Products, Marketing and Distribution

The Partnership has acquired undeveloped leasehold interests and drilled oil and gas properties located in Texas and New Mexico. All activities of the Partnership are confined to the continental United States. All oil and gas produced from these properties will be sold to unrelated third parties in the oil and gas business.

The revenues generated from the Partnership's oil and gas activities are dependent upon the current market for oil and gas. The prices received by the Partnership for its oil and gas production depend upon numerous factors beyond the Partnership's control, including competition, economic, political and regulatory developments and competitive energy sources, and make it particularly difficult to estimate future prices of oil and natural gas.

Following is a table of the ratios of revenues received from oil and gas production for the last three years:

| | Oil | Gas |
|---|---|---|
| 2003 | 76% | 24% |
| 2002 | 75% | 25% |
| 2001 | 72% | 28% |

As the table indicates, the majority of the Partnership's revenue is from its oil production; therefore, Partnership revenues will be highly dependent upon the future prices and demands of oil.

## Seasonality of Business

Although the demand for natural gas can be effected by seasonality, with higher demand in the colder winter months and in very hot summer months, the Partnership has not experienced material price and volume changes due to seasonality and has been able to sell all of its natural gas, either through contracts in place or on the spot market at the then prevailing spot market price.

## Customer Dependence

No material portion of the Partnership's business is dependent on a single purchaser, or a very few purchasers, where the loss of one would have a material adverse impact on the Partnership. Three purchasers accounted for 91% of the Partnership's total oil and gas production during 2003: Plains Marketing LP for 60%, Duke Energy Field Services LP 18% and Navajo Refining Company, Inc. for 13%. Contracts for 2003 with these major purchasers cover time periods ranging from month to month contracts up to year-year contract periods. Prices received from these major purchasers ranged from a low of $29.51 per Bbl to a high of $29.72 per Bbl and $4.73 per mcf. Three purchasers accounted for 95% of the Partnership's total oil and gas production during 2002: Plains Marketing LP for 59%, Duke Energy Field Services LP for 19% and Navajo Refining Company, Inc. for 17%. Contracts for 2002 with these major purchasers cover time periods ranging from month to month contracts up to year-year contract periods. Prices received from these major purchasers ranged from a low of $22.73 per Bbl to a high of $23.02 per Bbl and $2.86 per mcf. Three purchasers accounted for 93% of the Partnership's total oil and gas production during 2001: Plains Marketing LP for 58%, Duke Energy Field Services for 21% and Navajo Refining Company, Inc. for 14%. Contracts for 2001 with these major purchasers cover time periods ranging from month to month contracts up to year-year contract periods. Prices received from these major purchasers ranged from a low of $27.00 per Bbl to a high of $27.33 per Bbl and $4.90 per mcf. All purchasers of the Partnership's oil and gas production are unrelated third parties. In the event this purchaser were to discontinue purchasing the Partnership's production, the Managing General Partner believes that a substitute purchaser or purchasers could be located without undue delay. No other purchaser accounted for an amount equal to or greater than 10% of the Partnership's total oil and gas production.

Competition

Because the Partnership has utilized all of its funds available for the acquisition of drilling prospects and drilling activities, it is not subject to competition from other oil and gas property purchasers. See Item 2, Properties.

Factors that may adversely affect the Partnership include delays in completing arrangements for the sale of production, availability of a market for production, rising operating costs of producing oil and gas and complying with applicable water and air pollution control statutes, increasing costs and difficulties of transportation, and marketing of competitive fuels. Moreover, domestic oil and gas must compete with imported oil and gas and with coal, atomic energy, hydroelectric power and other forms of energy.

Regulation

Oil and Gas Production - The production and sale of oil and gas is subject to federal and state governmental regulation in several respects, such as existing price controls on natural gas and possible price controls on crude oil, regulation of oil and gas production by state and local governmental agencies, pollution and environmental controls and various other direct and indirect regulation. Many jurisdictions have periodically imposed limitations on oil and gas production by restricting the rate of flow for oil and gas wells below their actual capacity to produce and by imposing acreage limitations for the drilling of wells. The federal government has the power to permit increases in the amount of oil imported from other countries and to impose pollution control measures. Various aspects of the Partnership's oil and gas activities are regulated by administrative agencies under statutory provisions of the states where such activities are conducted and by certain agencies of the federal government for operations on Federal leases. The regulatory burden on the oil and gas industry increases the Partnership's cost of doing business, and, consequently, affects its profitability.

Regulation of Sales and Transportation of Natural Gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. In recent years, the FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system has been substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas supplies. In many instances, the results of Order No. 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. While the United States Court of Appeals upheld most of Order No. 636, certain related FERC orders, including the individual pipeline restructuring proceedings, are still subject to judicial review and may be reversed or remanded in whole or in part. While the outcome of these proceedings cannot be predicted with certainty, we do not believe that we will be affected materially differently than its competitors.

The FERC has also announced several important transportation-related policy statements and proposed rule changes, including a statement of policy and a request for comments concerning alternatives to its traditional cost-of-service rate making methodology to establish the rates interstate pipelines may charge for their services. A number of pipelines have obtained FERC authorization to charge negotiated rates as one such alternative. In February 1997, the FERC announced a broad inquiry into issues facing the natural gas industry to assist the FERC in establishing regulatory goals and priorities in the post-Order No. 636 environment. Similarly, the Texas Railroad Commission has been reviewing changes to its regulations governing transportation and gathering services provided by intrastate pipelines and gatherers. While the changes being considered by these federal and state regulators would affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC or state regulators will take on these matters, however, we do not believe that it will be affected by any action taken materially differently than other natural gas producers with which it competes.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Oil Price Controls and Transportation Rates. Sales of crude oil, condensate and gas liquids by us are not currently regulated and are made at market prices. The price we receive from the sale of these products may be affected by the cost of transporting the products to market.

Environmental and Health Controls. Extensive federal, state and local regulatory and common laws regulating the discharge of materials into the environment or otherwise relating to the protection of the environment affect our oil and natural gas operations. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent pollution, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases our cost of doing business and consequently affects our profitability. We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. However, environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect upon our capital expenditures, earnings or competitive position. Additionally, given the intense litigation environment in the United States, a threat exists of lawsuits alleging personal injury and property damage from environmental contamination alleged to be created by us or related entities. Potential liability in such lawsuits can include not only compensatory, but substantial punitive damages as well. We are not aware of any such suits currently pending or threatened.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA such persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, companies that incur liability frequently also confront third party claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site. Potential liability also exists under CERCLA for natural resource damage. A Natural Resource Damage Action (NRDA) could result in liability being assessed for restoration to natural resources.

The Federal Oil Pollution Act of 1990 ("OPA") regulates the release of oil into water or other areas designated by the statute. A release could result in our being held responsible for the cost of remediating the release, OPA specified damages and natural resource damages. The extent of such liability could be extensive. A release of oil in harmful quantities or other materials into water or other specified areas could also result in our being held responsible under the Clean Water Act ("CWA") for the costs of remediation, and any civil and criminal fines and penalties.

The Federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 ("RCRA"), regulates the generation, transportation, storage, treatment and disposal of solid and hazardous wastes and can require cleanup of abandoned hazardous waste disposal sites as well as waste management areas operating facilities. RCRA currently excludes drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as "hazardous waste." Disposal of such non-hazardous oil and natural gas exploration, development and production wastes usually are regulated by state law. Other wastes handled at exploration and production sites or used in the course of providing well services may not fall within this exclusion. Moreover, stricter standards for waste handling and disposal may be imposed on the oil and natural gas industry in the future. From time to time legislation is proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from the RCRA definition of "hazardous wastes" thereby potentially subjecting such wastes to more stringent handling, disposal and cleanup requirements. If such legislation were enacted it could have a significant impact on the operating costs of Southwest and Sierra, as well as the oil and natural gas industry and well servicing industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted. In addition, if our operations were to trigger regulation under RCRA, we could be required to satisfy certain financial criteria to ensure financial ability to comply with RCRA regulations. Proof of financial responsibility could be required in the form of dedicated trust funds, irrevocable letters of credit, posting of bonds, etc.

The Federal Clean Water Act ("CWA") contains provisions that may result in the imposition of certain water pollution control requirements with respect to water releases from our operations. We may be required to incur certain capital expenditures in the next several years for water pollution control equipment in connection with obtaining and maintaining National Pollutant Discharge Elimination Systems ("NPDES") permits. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities or well surfacing activities.

Our operations are also subject to the federal Clean Air Act ("CAA") and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities or well servicing activities.

We maintain insurance against "sudden and accidental" occurrences, which may cover some, but not all, of the environmental risks described above. Most significantly, the insurance we maintain will not cover the risks described above which occur over a sustained period of time. Further, there can be no assurance that such insurance will continue to be available to cover all such costs or that such insurance will be available at premium levels that justify its purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and operations.

Limited partners should be aware that the assessment of liability associated with environmental liabilities is not always correlated to the value of a particular project. Accordingly, liability associated with the environment under local, state, or federal regulations, particularly clean ups under CERCLA, can exceed the value of our investment in the associated site.

Regulation of Oil and Natural Gas Exploration and Production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits and drilling bonds for the drilling of wells, regulating the location of wells, the method of drilling and casing wells, and the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation matters, including provisions for the utilization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plugging and abandonment of such wells. Some state statutes limit the rate at which oil and natural gas can be produced from our properties.

Partnership Employees

The Partnership has no employees; however, the Managing General Partner has a staff of geologists, engineers, accountants, landmen and clerical staff who engage in Partnership activities and operations and perform additional services for the Partnership as needed. In addition to the Managing General Partner's staff, the Partnership engages independent consultants such as petroleum engineers and geologists as needed. As of December 31, 2003, there were 81 individuals directly employed by the Managing General Partner in various capacities.

Item 2. Properties

In determining whether an interest in a particular leasehold was to be acquired, the Managing General Partner considered such criteria as estimated drilling costs, estimated oil and gas reserves, estimated cash flow from the sale of future production, present and future prices of oil and gas, the extent of undeveloped and unproved reserves and the availability of markets.

As of December 31, 2003, the Partnership possessed an interest in oil and gas properties located in Ward County of Texas and Lea and Eddy Counties of New Mexico. These properties consist of various interests in 9 wells.

Due to the Partnership's objective of maintaining current operations without engaging in the additional drilling of any developmental or exploratory wells, or additional acquisitions of producing properties, there have not been any significant changes in properties during 2003, 2002 and 2001.

Significant Properties

The following table reflects the properties in which the Partnership has an interest:

| Name and Location | Date Purchased and Interest | No. of Wells | Proved Reserves* Oil (bbls) | Proved Reserves* Gas (mcf) |
|---|---|---|---|---|
| Mobil Fee G #1 Ward County, Texas | 12/92 at 100% working interest | 1 | 23,000<br>23,000(1) | 4,000<br>4,000(1) |
| Mobil Fee H #1 Ward County, | 12/92 at 100% | 1 | 43,000<br>43,000(1 | 158,000<br>158,000( |

| | | |
|---|---|---|
| Texas working interest | ) | 1) |

(1)Amounts represent proved developed reserves from currently producing zones.

*Ryder Scott Company, L.P. prepared the reserve and present value data for the Partnership's existing properties as of January 1, 2004. The reserve estimates were made in accordance with guidelines established by the Securities and Exchange Commission pursuant to Rule 4-10(a) of Regulation S-X. Such guidelines require oil and gas reserve reports be prepared under existing economic and operating conditions with no provisions for price and cost escalation except by contractual arrangements.

Oil price adjustments were made in the individual evaluations to reflect oil quality, gathering and transportation costs. The results of the reserve report as of January 1, 2004 are an average price of $31.76 per barrel.

Gas price adjustments were made in the individual evaluations to reflect BTU content, gathering and transportation costs and gas processing and shrinkage. The results of the reserve report as of January 1, 2004 are an average price of $5.30 per Mcf.

As also discussed in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, oil and gas prices were subject to frequent changes in 2003.

The evaluation of oil and gas properties is not an exact science and inevitably involves a significant degree of uncertainty, particularly with respect to the quantity of oil or gas that any given property is capable of producing. Estimates of oil and gas reserves are based on available geological and engineering data, the extent and quality of which may vary in each case and, in certain instances, may prove to be inaccurate. Consequently, properties may be depleted more rapidly than the geological and engineering data have indicated.

Unanticipated depletion, if it occurs, will result in lower reserves than previously estimated; thus an ultimately lower return for the Partnership. As new data is gathered during the subsequent year, the engineer must revise his earlier estimates. A year of new information, which is pertinent to the estimation of future recoverable volumes, is available during the subsequent year evaluation. In applying industry standards and procedures, the new data may cause the previous estimates to be revised. This revision may increase or decrease the earlier estimated volumes. Pertinent information gathered during the year may include actual production and decline rates, production from offset wells drilled to the same geologic formation, increased or decreased water production, workovers, and changes in lifting costs, among others. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered.

The Partnership has reserves, which are classified as proved developed. All of the proved reserves are included in the engineering reports, which evaluate the Partnership's present reserves.

The Partnership or the owners of properties in which the Partnership owns an interest can engage in workover projects or supplementary recovery projects, for example, to extract behind the pipe reserves. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

Item 3. Legal Proceedings

There are no material pending legal proceedings to which the Partnership is a party.

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

No matter was submitted to a vote of security holders during the fourth quarter of 2003 through the solicitation of proxies or otherwise.

## Part II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information
Investor partner interests, or units, in the Partnership were initially offered and sold for a price of $1,000. Investor partner units are not traded on any exchange and there is no public or organized trading market for them. Further, a transferee may not become a substitute limited or general partner without the consent of the Managing General Partner.

The Managing General Partner has the right, but not the obligation in accordance with the obligations set forth in the partnership agreement, to purchase limited partnership units should an investor desire to sell. The value of the unit is determined by adding the sum of (1) current assets less liabilities and (2) the present value of the future net revenues attributable to proved reserves and by discounting the future net revenues at a rate not in excess of the prime rate charged by Nations Bank, N.A. of Midland, Texas, plus one percent (1%), which value shall be further reduced by a risk factor discount of no more than one-third (1/3) to be determined by the Managing General Partner in its sole and absolute discretion under the partnership agreement.

Issuer Purchases of Equity Securities

| Period(1) | Total Number of Units Purchased | Average Price Paid Per Unit | Total Number of Units Purchased as Part of Publicly Announced Plans or Programs | Maximum Number (or Approximate Value) of Units that May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| October 1-31, 2003 | - | $ - | - | N/A |
| November 1-30, 2003 | - | - | - | N/A |
| December 1-31, 2003 | - | - | - | N/A |
| TOTALS | - | $ - | | |

(1) In July 2003, the Managing General Partner purchased a total of 10 limited partner units from limited partners at an average base price of $453.08 per unit. In 2002 and 2001, no limited partner units were purchased by the Managing General Partner. The discretionary repurchases were made based upon the partnership agreement.

Number of Limited and General Partner Interest Holders
As of December 31, 2003, there were 105 holders of limited partner units.

Distributions
Pursuant to Article IV, Section 4.01 of the Partnership's Certificate and Agreement of Limited Partnership, "Net Cash Flow" is distributed to the partners on a quarterly basis. "Net Cash Flow" is defined as "the cash generated by the Partnership's drilling activities, less (i) General and Administrative Costs, (ii) Operating Costs, and (iii) any reserves necessary to meet current and anticipated needs of the Partnership, including, but not limited to drilling cost overruns, as determined in the sole discretion of the Managing General Partner."

During 2003, distributions were made totaling $168,665, with $150,112 distributed to the investor partners and $18,553 to the Managing General Partners. For the year ended December 31, 2003, distributions of $106.69 per investor partner unit were made, based upon 1,407 investor partner units outstanding. During 2002, distributions were made totaling $112,957, with $100,532 distributed to the investor partners and $12,425 to the

Managing General Partners. For the year ended December 31, 2002, distributions of $71.45 per investor partner unit were made, based upon 1,407 investor partner units outstanding. During 2001, distributions were made totaling $208,798, with $185,830 distributed to the investor partners and $22,968 to the Managing General Partners. For the year ended December 31, 2001, distributions of $132.08 per investor partner unit were made, based upon 1,407 investor partner units outstanding.

## Item 6. Selected Financial Data

The following selected financial data for the year ended December 31, 2003, 2002, 2001, 2000 and 1999 should be read in conjunction with the financial statements included in Item 8:

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| Revenues | $ 349,284 | 275,362 | 333,192 | 372,553 | 249,965 |
| Net income before cumulative effects of accounting changes | 156,673 | 120,581 | 160,893 | 217,640 | 112,767 |
| Net income | 153,929 | 117,581 | 160,893 | 217,640 | 112,767 |
| Partners' share of net income: | | | | | |
| Managing General Partner | 18,472 | 14,804 | 20,338 | 25,590 | 14,274 |
| Investor partners | 135,457 | 102,777 | 140,555 | 192,050 | 98,493 |
| Investor partners' net income per unit before cumulative effects of accounting changes | 98.01 | 75.18 | 99.90 | 136.50 | 70.00 |
| Investor partners' net income (loss) per unit | 96.27 | 73.05 | 99.90 | 136.50 | 70.00 |
| Investor partners' cash distributions per unit | 106.69 | 71.45 | 132.08 | 142.10 | 53.77 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total assets | $ | 249,981 | 235,993 | 231,369 | 279,195 | 286,195 |

## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

### General

Southwest Developmental Drilling Fund 92-A, L.P. (the "Partnership" or "Registrant") was organized as a Delaware limited partnership on May 5, 1992. The offering of limited and general partner interests began August 11, 1992 as part of a shelf offering registered under the name Southwest Developmental Drilling Program 1991-92. Minimum capital requirements for the Partnership were met on December 28, 1992, with the offering of limited and general partner interests concluding December 31, 1992, with total investor partner contributions of $1,407,000. The Managing General Partner made a contribution to the capital of the Partnership at the conclusion of the offering period in an amount equal to 1% of its net capital contributions. The Managing General Partner contribution was $12,030.

The Partnership was formed to engage primarily in the business of drilling developmental and exploratory wells, to produce and market crude oil and natural gas produced from such properties, to distribute any net proceeds from operations to the general and limited partners and to the extent necessary acquire leases, which contain drilling prospects. Net revenues will not be reinvested in other revenue producing assets except to the extent that performance of remedial work is needed to improve a well's producing capabilities. The economic life of the Partnership thus depends on the period over which the Partnership's oil and gas reserves are economically recoverable.

Based on current conditions, management anticipates performing no workovers to enhance production. The partnership will most likely experience the historical production decline, which has approximated 10% per year. Accordingly, if commodity prices remain unchanged, the Partnership expects future earnings to decline due to anticipated production declines.

### Critical Accounting Policies

Full cost ceiling calculations The Partnership follows the full cost method of accounting for its oil and gas properties. The full cost method subjects companies to quarterly calculations of a "ceiling", or limitation on the amount of properties that can be capitalized on the balance sheet. If the Partnership's capitalized costs are in excess of the calculated ceiling, the excess must be written off as an expense.

The Partnership's discounted present value of its proved oil and natural gas reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data. The Partnership's reserve estimates are prepared by outside consultants.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost property writedown. In addition to the impact of these estimates of proved reserves on calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of DD&A.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than the Partnership's long-term price forecast that is a barometer for true fair value.

In 2002, the Partnership changed methods of accounting for depletion of capitalized costs from the units-of-revenue method to the units-of-production method. The newly adopted accounting principle is preferable in the circumstances because the units-of-production method results in a better matching of the costs of oil and gas production against the related revenue received in periods of volatile prices for production as have been experienced in recent periods. Additionally, the units-of-production method is the predominant method used by full cost companies in the oil and gas industry, accordingly, the change improves the comparability of the Partnership's financial statements with its peer group.

## Results of Operations

A. General Comparison of the Years Ended December 31, 2003 and 2002

The following table provides certain information regarding performance factors for the years ended December 31, 2003 and 2002:

| | Year Ended | Percenta ge |
|---|---|---|

| | | December 31, 2003 | 2002 | Increase (Decrease) |
|---|---|---|---|---|
| Average price per barrel of oil | $ | 30.12 | 24.56 | 23% |
| Average price per mcf of gas | $ | 4.67 | 3.05 | 53% |
| Oil production in barrels | | 8,700 | 8,410 | 3% |
| Gas production in mcf | | 17,500 | 22,000 | (20%) |
| Oil and gas revenue | $ | 343,751 | 273,741 | 26% |
| Production expense | $ | 153,850 | 123,272 | 25% |
| Partnership distributions | $ | 168,665 | 112,957 | 49% |
| Limited partner distributions | $ | 150,112 | 100,532 | 49% |
| Per unit distribution to limited partners | $ | 106.69 | 71.45 | 49% |
| Number of limited partner units | | 1,407 | 1,407 | |

Revenues

The Partnership's oil and gas revenues increased to $343,751 from $273,741 for the years ended December 31, 2003 and 2002, respectively, an increase of 26%. The principal factors affecting the comparison of the years ended December 31, 2003 and 2002 are as follows:

1. The average price for a barrel of oil received by the Partnership increased during the year ended December 31, 2003 as compared to the year ended December 31, 2002 by 23%, or $5.56 per barrel, resulting in an increase of approximately $48,400 in revenues. Oil sales represented 76% of total oil and gas sales during the year ended December 31, 2003 as compared to 75% during the year ended December 31, 2002.

   The average price for an mcf of gas received by the Partnership increased during the same period by 53%, or $1.62 per mcf, resulting in an increase of approximately $28,400 in revenues.

   The total increase in revenues due to the change in prices received from oil and gas production is approximately $76,800. The market price for oil and gas has been extremely volatile over the past decade and management expects a certain amount of volatility to continue in the foreseeable future.

2. Oil production increased approximately 290 barrels or 3% during the

year ended December 31, 2003 as compared to the year ended December 31, 2002, resulting in an increase of approximately $7,100 in revenues.

Gas production decreased approximately 4,500 mcf or 20% during the same period, resulting in a decrease of approximately $13,700 in revenues.

The net total decrease in revenues due to the change in production is approximately $6,600. The decrease in gas volumes is due to the sharp production decline on one well.

3. Other income in the amount of $5,533 for 2003 primarily represents litigation settlement income from a class action lawsuit, where two purchasers were underpaying for certain types of oil in certain locations for the time periods of 1988-1998.

Costs and Expenses

Total costs and expenses increased to $192,611 from $154,781 for the years ended December 31, 2003 and 2002, respectively, an increase of 24%. The increase is the result of the addition of accretion expense, higher lease operating costs and general and administrative expense.

1. Lease operating costs and production taxes were 25% higher, or approximately $30,600 more during the year ended December 31, 2003 as compared to the year ended December 31, 2002. The increase in lease operating costs are due to increased well repairs on two wells and compressor charges on one well and an increase in production taxes due to an increase in oil and gas commodity prices.

2. General and administrative costs consist of independent accounting and engineering fees, computer services, postage, and Managing General Partner personnel costs. General and administrative costs increased 29% or approximately $5,100 during the year ended December 31, 2003 as compared to the year ended December 31, 2002. The increase in general and administrative expense is due to an increase in independent accounting review and audit fees.

3. Depletion expense was $14,000 for the year ended December 31, 2003 the same as 2002. The year ended December 31, 2003, was $1.21 applied to 11,617 BOE as compared to $1.16 applied to 12,077 BOE for the same period in 2002.

Cumulative effect of change in accounting principle

On January 1, 2003, the Partnership adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS No. 143"). Adoption of SFAS No. 143 is required for all companies with fiscal years beginning after June 15, 2002. The new standard requires the Partnership to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and to capitalize an equal amount as a cost of the asset and depreciate the additional cost over the estimated useful life of the asset. On January 1, 2003, the Partnership recorded additional costs, net of accumulated depreciation, of approximately $23,838, a long term liability of approximately $26,582 and a loss of approximately $2,744 for the cumulative effect on depreciation of the additional costs and accretion expense on the liability related to expected abandonment costs of its oil and natural gas producing properties. At December 31, 2003, the asset retirement obligation was $28,708, and the increase in the balance from January 1, 2003 of $2,126 is due to accretion expense. The pro forma amounts of the asset retirement obligation as of December 31, 2002, 2001 and 2000, were approximately $26,582, $24,626 and $22,814, respectively. The pro forma amounts of the asset retirement obligation were measured using information, assumptions and interest rates as of the adoption date of January 1, 2003.

Results of Operations

B. General Comparison of the Years Ended December 31, 2002 and 2001

The following table provides certain information regarding performance factors for the years ended December 31, 2002 and 2001:

| | | Year Ended December 31, 2002 | 2001 | Percentage Increase (Decrease) |
|---|---|---|---|---|
| | | ---- | ---- | --------- |
| Average price per barrel of oil | $ | 24.56 | 25.25 | (3%) |
| Average price per mcf of gas | $ | 3.05 | 4.08 | (25%) |
| Oil production in barrels | | 8,410 | 9,460 | (11%) |
| Gas production in mcf | | 22,000 | 23,000 | (4%) |
| Oil and gas revenue | $ | 273,741 | 332,643 | (18%) |
| Production expense | $ | 123,272 | 131,781 | (6%) |
| Partnership distributions | $ | 112,957 | 208,798 | (46%) |
| Limited partner distributions | $ | 100,532 | 185,830 | (46%) |
| Per unit distribution to limited partners | $ | 71.45 | 132.08 | (46%) |
| Number of limited partner units | | 1,407 | 1,407 | |

Revenues

The Partnership's oil and gas revenues decreased to $273,741 from $332,643 for the years ended December 31, 2002 and 2001, respectively, a decrease of 18%. The principal factors affecting the comparison of the years ended December 31, 2002 and 2001 are as follows:

1. The average price for a barrel of oil received by the Partnership decreased during the year ended December 31, 2002 as compared to the year ended December 31, 2001 by 3%, or $.69 per barrel, resulting in a decrease of approximately $5,800 in revenues. Oil sales represented 75% of total oil and gas sales during the year ended December 31, 2002 as compared to 72% during the year ended December 31, 2001.

   The average price for an mcf of gas received by the Partnership decreased during the same period by 25%, or $1.03 per mcf, resulting in a decrease of approximately $22,700 in revenues.

   The total decrease in revenues due to the change in prices received from oil and gas production is approximately $28,500. The market price for oil and gas has been extremely volatile over the past decade and management expects a certain amount of volatility to continue in the foreseeable future.

2. Oil production decreased approximately 1,050 barrels or 11% during the year ended December 31, 2002 as compared to the year ended December 31, 2001, resulting in a decrease of approximately $26,500 in revenues.

   Gas production decreased approximately 1,000 mcf or 4% during the same period, resulting in a decrease of approximately $4,100 in revenues.

   The total decrease in revenues due to the change in production is approximately $30,600.

Costs and Expenses

Total costs and expenses decreased to $154,781 from $172,299 for the years ended December 31, 2002 and 2001, respectively, a decrease of 10%. The decrease is the result of lower lease operating costs and depletion expense, partially offset by an increase general and administrative expense.

2. Lease operating costs and production taxes were 6% lower, or approximately $8,500 less during the year ended December 31, 2002 as compared to the year ended December 31, 2001.

2. General and administrative costs consist of independent accounting and engineering fees, computer services, postage, and Managing General Partner personnel costs. General and administrative costs increased 6%

or approximately $1,000 during the year ended December 31, 2002 as compared to the year ended December 31, 2001.

3. Depletion expense decreased to $14,000 for the year ended December 31, 2002 from $24,000 for the same period in 2001. This represents a decrease of 42%. In the fourth quarter of 2002, the Partnership changed methods of accounting for depletion of capitalized costs from the units-of-revenue method to the units-of-production method. The newly adopted accounting principle is preferable in the circumstances because the units-of-production method results in a better matching of the costs of oil and gas production against the related revenue received in periods of volatile prices for production as have been experienced in recent periods. Additionally, the units-of-production method is the predominant method used by full cost companies in the oil and gas industry, accordingly, the change improves the comparability of the Partnership's financial statements with its peer group. The effect of this change in method resulted in no change to 2002 depletion expense, however, it decreased 2002 net income by $3,000. See Note 4 of the notes to the Partnership's financial statements.

   The major factor in the decrease in depletion expense between the comparative periods was the increase in the price of oil and gas used to determine the Partnership's reserves for January 1, 2003 as compared to 2002, which provided more economically recoverable proved reserves at January 1, 2003 which caused the depletion rate per equivalent unit produced to decline. Also, as discussed above, the total equivalent units produced in 2002 declined from 2001.

C. Revenue and Distribution Comparison

Partnership net income for the years ended December 31, 2003, 2002 and 2001 was $153,929, $117,581 and $160,893, respectively. Partnership distributions for the years ended December 31, 2003, 2002 and 2001 were $168,665, $112,957 and $208,798, respectively. These differences are indicative of the changes in oil and gas prices, production and property during 2003, 2002 and 2001.

The sources for the 2003 distributions of $168,665 were oil and gas operations of approximately $172,300 and the change in oil and gas properties of approximately $(600), resulting in excess cash for contingencies or subsequent distributions. The sources for the 2002 distributions of $112,957 were oil and gas operations of approximately $124,000 and the change in oil and gas properties of approximately $(10), resulting in excess cash for contingencies or subsequent distributions. The sources for the 2001 distributions of $208,798 were oil and gas operations of approximately $197,000 and the change in oil and gas properties of approximately $1,400, with the balance from available cash on hand at the beginning of the period.

Total distributions during the year ended December 31, 2003 were $168,665 of which $150,112 was distributed to the investor partners and $18,553 to the Managing General Partners. The per unit distribution to investor partners during the same period was $106.69. Total distributions during the year ended December 31, 2002 were $112,957 of which $100,532 was distributed to the investor partners and $12,425 to the Managing General Partners. The per unit distribution to investor partners during the same period was $71.45. Total distributions during the year ended December 31, 2001 were $208,798 of which $185,830 was distributed to the investor partners and $22,968 to the Managing General Partners. The per unit distribution to investor partners during the same period was $132.08.

Cumulative cash distributions of $1,867,975 have been made to the general and limited partners as of December 31, 2003. As of December 31, 2003, $1,662,874 or $1,181.68 per investor partner unit, has been distributed to the investor partners, representing a 100% return of capital and a 18% return on capital contributed.

Liquidity and Capital Resources
The primary source of cash is from operations, the receipt of income from oil and gas properties. The Partnership anticipates the primary source of cash to continue being from the oil and gas operations.

Cash flows provided by operating activities were approximately $172,300 in 2003 compared to $124,000 in 2002 and approximately $197,000 in 2001.

Cash flows (used in) provided by investing activities were approximately $(600) in 2003 compared to $(10) in 2002 and approximately $1,400 in 2001. The primary use of the 2003 cash flow from investing activities was the change in oil and gas properties.

Cash flows used in financing activities were approximately $168,600 in 2003 compared to $113,000 in 2002 and approximately $208,700 in 2001. The only use in the 2003 financing activities was the distributions to partners.

As of December 31, 2003, the Partnership had $70,700 in working capital. The Managing General Partner knows of no unusual contractual commitments. Although the Partnership held many long-lived properties at inception, because of the restrictions on property development imposed by the partnership agreement, the Partnership cannot develop its non producing properties, if any. Without continued development, the producing reserves continue to deplete. Accordingly, as the Partnership's properties have matured and depleted, the net cash flows from operations for the Partnership has steadily declined, except in periods of substantially increased commodity pricing. Maintenance of properties and administrative expenses for the Partnership are increasing relative to production. As the properties continue to deplete, maintenance of properties and administrative costs as a percentage of production are expected to continue to increase.

## Liquidity - Managing General Partner

As of December 31, 2003, the Managing General Partner is in violation of several covenants pertaining to their Amended and Restated Revolving Credit Agreement due June 1, 2006 and their Senior Second Lien Secured Credit Agreement due October 15, 2008. Due to the covenant violations, the Managing General Partner is in default under their Amended and Restated Revolving Credit Agreement and the Senior Second Lien Secured Credit Agreement, and all amounts due under these agreements have been classified as a current liability on the Managing General Partner's balance sheet at December 31, 2003. The significant working capital deficit and debt being in default at December 31, 2003, raise substantial doubt about the Managing General Partner's ability to continue as a going concern.

Subsequent to December 31, 2003, the Board of Directors of the Managing General Partner announced its decision to explore a merger, sale of the stock or other transaction involving the Managing General Partner. The Board has formed a Special Committee of independent directors to oversee the sales process. The Special Committee has retained independent financial and legal advisors to work closely with the management of the Managing General Partner to implement the sales process. There can be no assurance that a sale of the Managing General Partner will be consummated or what terms, if consummated, the sale will be on.

## Recent Accounting Pronouncements

The EITF is considering two issues related to the reporting of oil and gas mineral rights. Issue No. 03-O, "Whether Mineral Rights Are Tangible or Intangible Assets," is whether or not mineral rights are intangible assets pursuant to SFAS No. 141, "Business Combinations." Issue No. 03-S, "Application of SFAS No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Companies," is, if oil and gas drilling rights are intangible assets, whether those assets are subject to the classification and disclosure provisions of SFAS No. 142. The Partnership classifies the cost of oil and gas mineral rights as properties and equipment and believes that this is consistent with oil and gas accounting and industry practice. The disclosures required by SFAS Nos. 141 and 142 would be made in the notes to the financial statements. There would be no effect on the statement of income or cash flows as the intangible assets related to oil and gas mineral rights would continue to be amortized under the full cost method of accounting.

## Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Partnership is not a party to any derivative or embedded derivative instruments.

Item 8. Financial Statements and Supplementary Data

## Index to Financial Statements



## INDEPENDENT AUDITORS' REPORT

The Partners
Southwest Developmental Drilling
Fund 92-A
(A Delaware Limited Partnership):

We have audited the accompanying balance sheets of Southwest Developmental Drilling Fund 92-A (the "Partnership") as of December 31, 2003 and 2002, and the related statements of operations, changes in partners' equity and cash flows for each of the years in the three year period ended December 31, 2003. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Southwest Developmental Drilling Fund 92-A as of December 31, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 4 to the financial statements, the Partnership changed its method of computing depletion in 2002. Also, as discussed in Note 3 to the financial statements, the Partnership changed its method of accounting for asset retirement obligations as of January 1, 2003.

KPMG LLP

Midland, Texas
March 19, 2004, except as to Note 9, which is as of May 3, 2004

Southwest Developmental Drilling Fund 92-A, L.P.
(a Delaware limited partnership)
Balance Sheets
December 31, 2003 and 2002

| | | 2003 | 2002 |
|---|---|---|---|
| Assets | | | |
| Current assets: | | | |
| Cash and cash equivalents | $ | 30,713 | 27,569 |
| Receivable from Managing General Partner | | 39,984 | 39,532 |
| Total current assets | | 70,697 | 67,101 |
| Oil and gas properties - using the full-cost method of accounting | | 1,326,16 | 1,313,13 |

| | | |
|---|---|---|
| | 8 | 2 |
| Less accumulated depreciation, depletion and amortization | 1,146,884 | 1,144,240 |
| Net oil and gas properties | 179,284 | 168,892 |
| | $ 249,981 | 235,993 |

**Liabilities and Partners' Equity**

| | | |
|---|---|---|
| Current liability - distribution payable | $ 95 | 79 |
| Asset retirement obligation | 28,708 | 9 |
| Partners' equity: | | |
| Managing General Partner | 30,222 | 30,303 |
| Investor partners | 190,956 | 205,611 |
| Total partners' equity | 221,178 | 235,914 |
| | $ 249,981 | 235,993 |

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

Southwest Developmental Drilling Fund 92-A, L.P.
(a Delaware limited partnership)
Statements of Operations
For the years ended December 31, 2003, 2002 and 2001

| | | 2003 | 2002 | 2001 |
|---|---|---|---|---|
| **Revenues** | | | | |
| Oil and gas sales | $ | 343,751 | 273,741 | 332,643 |
| Interest income from operations | | - | 92 | 549 |
| Other | | 5,533 | 1,529 | - |
| | | 349,284 | 275,362 | 333,192 |
| **Expenses** | | | | |
| Production | | 153,850 | 123,272 | 131,781 |
| General and administrative | | 22,635 | 17,509 | 16,518 |
| Accretion of asset retirement obligation | | 2,126 | - | - |
| Depreciation, depletion and amortization | | 14,000 | 14,000 | 24,000 |
| | | 192,611 | 154,781 | 172,299 |
| Net income before cumulative effect of accounting changes | | 156,673 | 120,581 | 160,893 |
| Cumulative effect of change in accounting principle - SFAS No. 143 - See Note 3 | | (2,744) | - | - |
| Cumulative effect of change in accounting principle - change in depletion method - See Note 4 | | - | (3,000) | - |
| Net income | $ | 153,929 | 117,581 | 160,893 |
| Net income allocated to: | | | | |
| Managing General Partner | $ | 18,472 | 14,804 | 20,338 |

| | | | | |
|---|---|---|---|---|
| Investor partners | $ | 135,457 | 102,777 | 140,555 |
| | | ====== | ====== | ====== |
| Per investor partner unit before cumulative effect | $ | 98.01 | 75.18 | 99.90 |
| Cumulative effects per investor partner unit | | (1.74) | (2.13) | - |
| | | ---------- | ---------- | ---------- |
| Per investor partner unit | $ | 96.27 | 73.05 | 99.90 |
| | | ====== | ====== | ====== |
| Pro forma amounts assuming changes are applied retroactively (See Notes 3 and 4 for details): | | | | |
| Net income before cumulative effect | $ | - | 118,625 | 163,081 |
| | | ====== | ====== | ====== |
| Per investor partner unit (1,407.0 units) | $ | - | 73.94 | 101.59 |
| | | ====== | ====== | ====== |

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

Southwest Developmental Drilling Fund 92-A, L.P.
(a Delaware limited partnership)
Statement of Changes in Partners' Equity
Years ended December 31, 2003, 2002 and 2001

| | | Managing General Partner | Investor Partners | Total |
|---|---|---|---|---|
| | | -------- | -------- | ----- |
| Balance at December 31, 2000 | $ | 30,554 | 248,641 | 279,195 |
| Net income | | 20,338 | 140,555 | 160,893 |
| Distributions | | (22,968) | (185,830) | (208,798) |
| | | ---------- | ----------- | ----------- |
| Balance at December 31, 2001 | | 27,924 | 203,366 | 231,290 |
| Net income | | 14,804 | 102,777 | 117,581 |
| Distributions | | (12,425) | (100,532) | (112,957) |

| | | | | |
|---|---|---|---|---|
| Balance at December 31, 2002 | | 30,303 | 205,611 | 235,914 |
| Net income | | 18,472 | 135,457 | 153,929 |
| Distributions | | (18,553) | (150,112) | (168,665) |
| Balance at December 31, 2003 | $ | 30,222 | 190,956 | 221,178 |

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

Southwest Developmental Drilling Fund 92-A, L.P.
(a Delaware limited partnership)
Statements of Cash Flows
Years ended December 31, 2003, 2002 and 2001

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Cash received from oil and gas sales | $ 337,671 | 257,856 | 353,274 |

| | | | | |
|---|---|---|---|---|
| Cash paid to Managing General Partner for administrative fees and general and administrative overhead | | (170,857) | (135,451) | (156,854) |
| Interest received | | - | 92 | 549 |
| Miscellaneous settlement | | 5,533 | 1,529 | - |
| | | ---------- | ---------- | ---------- |
| Net cash provided by operating activities | | 172,347 | 124,026 | 196,969 |
| | | ---------- | ---------- | ---------- |
| Cash flows from investing activities: | | | | |
| Addition to oil and gas properties | | (554) | (8) | - |
| Sale of equipment | | - | - | 1,393 |
| | | ---------- | ---------- | ---------- |
| Net cash (used in) provided by investing activities | | (554) | (8) | 1,393 |
| | | ---------- | ---------- | ---------- |
| Cash flows used in financing activities: | | | | |
| Distributions to partners | | (168,649) | (112,957) | (208,719) |
| | | ---------- | ---------- | ---------- |
| Net increase (decrease) in cash and cash equivalents | | 3,144 | 11,061 | (10,357) |
| Beginning of period | | 27,569 | 16,508 | 26,865 |
| | | ---------- | ---------- | ---------- |
| End of period | $ | 30,713 | 27,569 | 16,508 |
| | | ====== | ====== | ====== |
| Reconciliation of net income to net cash provided by operating activities: | | | | |
| Net income | $ | 153,929 | 117,581 | 160,893 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | | |

| | | | | |
|---|---|---|---|---|
| Depreciation, depletion and amortization | | 14,000 | 14,000 | 24,000 |
| Accretion of asset retirement obligation | | 2,126 | - | - |
| Cumulative effect of change in accounting principle | | 2,744 | 3,000 | - |
| (Increase) decrease in receivables | | (6,080) | (15,885) | 20,631 |
| Increase (decrease) in payables | | 5,628 | 5,330 | (8,555) |
| | | ---------- | ---------- | ---------- |
| Net cash provided by operating activities | $ | 172,347 | 124,026 | 196,969 |
| | | ====== | ====== | ====== |
| Noncash investing and financing activities: | | | | |
| Increase in oil and gas properties - Adoption of SFAS No. 143 | $ | 23,838 | - | - |
| | | ====== | ====== | ====== |

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

Southwest Developmental Drilling Fund 92-A, L.P.
(a Delaware limited partnership)

## Notes to Financial Statements

1. Organization

Southwest Developmental Drilling Fund 92-A, L.P. was organized under the laws of the state of Delaware on May 5, 1992, for the purpose of engaging primarily in the business of drilling developmental and exploratory wells, to produce and market crude oil and natural gas produced from such properties, and acquire leases, which contain drilling prospects. The activities of the Partnership should continue for a term of 50 years, unless terminated at an earlier date as provided for in the Partnership Agreement. The Partnership anticipates selling its oil and gas production to a variety of purchasers with the prices it receives being dependent upon the oil and gas economy. Southwest Royalties, Inc. serves as the Managing General Partner. Revenues, costs and expenses are allocated as follows:

| | Managing General Partner | Investor Partners |
|---|---|---|
| Interest income on capital | - | 100% |

| | | |
|---|---|---|
| contributions | | |
| Oil and gas sales* | 11% | 89% |
| All other revenues* | 11% | 89% |
| Organization and offering costs (1) | - | 100% |
| Syndication costs | - | 100% |
| Amortization of organization costs | - | 100% |
| Lease acquisition costs | 1% | 99% |
| Gain/loss on property disposition* | 11% | 89% |
| Operating and administrative costs*(2) | 11% | 89% |
| Depreciation, depletion and amortization | | |
| of oil and gas properties | - | 100% |
| Intangible drilling and development costs | - | 100% |
| All other costs* | 11% | 89% |

*After the Investor Partners have received distributions totaling 150% of their capital contributions, the allocation will change to 15% Managing General Partner and 85% Investor Partners.

(1) All organization costs in excess of 4% of initial capital contributions will be paid by the Managing General Partner and will be treated as a capital contribution. The Partnership paid the Managing General Partner an amount equal to 4% of initial capital contributions for such organization costs.

(2) Administrative costs in any year, which exceed 2% of capital contributions shall be paid by the Managing General Partner and will be treated as a capital contribution.

2. Summary of Significant Accounting Policies

Oil and Gas Properties
Oil and gas properties are accounted for at cost under the full-cost method. Under this method, all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of oil and gas reserves are capitalized. Gain or loss on the sale of oil and gas properties is not recognized unless significant oil and gas reserves are involved.

Should the net capitalized costs exceed the estimated present value of oil and gas reserves, discounted at 10%, such excess costs would be charged to current expense. In applying the units-of-revenue method for the year ended December 31, 2001, we have not excluded royalty and net profit interest payments from gross revenues as all of our royalty and net profit interests have been purchased and capitalized to the depletion basis of our proved oil and gas properties. As of December

31, 2003, 2002 and 2001, the net capitalized costs did not exceed the estimated present value of oil and gas reserves.



2. Summary of Significant Accounting Policies - continued

Estimates and Uncertainties
The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Partnerships depletion calculation and full-cost ceiling test for oil and gas properties uses oil and gas reserves estimates, which are inherently imprecise. Actual results could differ from those estimates.

Syndication Costs
Syndication costs are accounted for as a reduction of partnership equity.

Environmental Costs
The Partnership is subject to extensive federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require the Partnership to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Costs, which improve a property as compared with the condition of the property when originally constructed or acquired and costs, which prevent future environmental contamination are capitalized. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated.

Revenue Recognition
We recognize oil and gas sales when delivery to the purchaser has occurred and title has transferred. This occurs when production has been delivered to a pipeline or transport vehicle.

Gas Balancing
The Partnership utilizes the sales method of accounting for over or under deliveries of gas. Under this method, the Partnership records

revenues based on the payments it has received for sales from purchasers. As of December 31, 2003 and 2002, the Partnership was not over or under produced.

Income Taxes
No provision for income taxes is reflected in these financial statements, since the tax effects of the Partnership's income or loss are passed through to the individual partners.

In accordance with the requirements of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes," the Partnership's tax basis in its net oil and gas assets at December 31, 2003 and 2002 was $170,944 and $172,009, respectively, less than that shown on the accompanying Balance Sheets in accordance with generally accepted accounting principles.

Cash and Cash Equivalents
For purposes of the statement of cash flows, the Partnership considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. The Partnership maintains its cash at one financial institution.

Investor Partner Units
As of December 31, 2003, 2002 and 2001, there were 1,407 investor units outstanding held by 105 partners.

Concentrations of Credit Risk
The Partnership is subject to credit risk through trade receivables. Although a substantial portion of its debtors' ability to pay is dependent upon the oil and gas industry, credit risk is minimized due to a large customer base. All partnership revenues are received by the Managing General Partner and subsequently remitted to the partnership and all expenses are paid by the Managing General Partner and subsequently reimbursed by the partnership.



2. Summary of Significant Accounting Policies - continued

Fair Value of Financial Instruments
The carrying amount of cash and accounts receivable approximates fair value due to the short maturity of these instruments.

Net Income (loss) per limited partnership unit
The net income (loss) per limited partnership unit is calculated by using the number of outstanding limited partnership units.

Recent Accounting Pronouncements

The EITF is considering two issues related to the reporting of oil and gas mineral rights. Issue No. 03-O, "Whether Mineral Rights Are Tangible or Intangible Assets," is whether or not mineral rights are intangible assets pursuant to SFAS No. 141, "Business Combinations." Issue No. 03-S, "Application of SFAS No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Companies," is, if oil and gas drilling rights are intangible assets, whether those assets are subject to the classification and disclosure provisions of SFAS No. 142. The Partnership classifies the cost of oil and gas mineral rights as properties and equipment and believes that this is consistent with oil and gas accounting and industry practice. The disclosures required by SFAS Nos. 141 and 142 would be made in the notes to the financial statements. There would be no effect on the statement of income or cash flows as the intangible assets related to oil and gas mineral rights would continue to be amortized under the full cost method of accounting.

Depletion Policy

In 2002, the Partnership changed methods of accounting for depletion of capitalized costs from the units-of-revenue method to the units-of-production method. (See Note 4)

3. Cumulative effect of change in accounting principle - SFAS No. 143

On January 1, 2003, the Partnership adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS No. 143"). Adoption of SFAS No. 143 is required for all companies with fiscal years beginning after June 15, 2002. The new standard requires the Partnership to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and to capitalize an equal amount as a cost of the asset and depreciate the additional cost over the estimated useful life of the asset. On January 1, 2003, the Partnership recorded additional costs, net of accumulated depreciation, of approximately $23,838, a long term liability of approximately $26,582 and a loss of approximately $2,744 for the cumulative effect on depreciation of the additional costs and accretion expense on the liability related to expected abandonment costs of its oil and natural gas producing properties. At December 31, 2003, the asset retirement obligation was $28,708, and the increase in the balance from January 1, 2003 of $2,126 is due to accretion expense. The pro forma amounts of the asset retirement obligation as of December 31, 2002, 2001 and 2000, were approximately $26,582, $24,626 and $22,814, respectively. The pro forma amounts of the asset retirement obligation were measured using information, assumptions and interest rates as of the adoption date of January 1, 2003. The pro forma amounts for the years ended December 31, 2002 and 2001, which are presented below, reflect the effect of retroactive application of SFAS No. 143.

| | 2002 | 2001 |
|---|---|---|

| | | | |
|---|---|---|---|
| | | ---- | ---- |
| Pro forma amounts assuming change is applied retroactively: | | | |
| Net income before cumulative effect for change in depletion | $ | 118,625 | 159,081 |
| | | ====== | ====== |
| Per investor partner unit (1,407.0 units) | $ | 73.94 | 98.75 |
| | | ====== | ====== |
| Net income | $ | 115,625 | 159,081 |
| | | ====== | ====== |
| Per investor partner unit (1,407.0 units) | $ | 71.80 | 98.75 |
| | | ====== | ====== |

Southwest Developmental Drilling Fund 92-A, L.P.
(a Delaware limited partnership)

Notes to Financial Statements

4. Cumulative effect of a change in accounting principle - change in depletion method

In 2002, the Partnership changed methods of accounting for depletion of capitalized costs from the units-of-revenue method to the units-of-production method. The newly adopted accounting principle is preferable in the circumstances because the units-of-production method results in a better matching of the costs of oil and gas production against the related revenue received in periods of volatile prices for production as have been experienced in recent periods. Additionally, the units-of-production method is the predominant method used by full cost companies in the oil and gas industry, accordingly, the change improves the comparability of the Partnership's financial statements with its peer group. The Partnership adopted the units-of-production method through the recording of a cumulative effect of a change in accounting principle in the amount of $3,000 effective as of January 1, 2002. The Partnership's depletion for the years ended 2003 and 2002 have been calculated using the units-of-production method and 2001 has not been restated. The pro forma amounts for 2001, which are presented below, reflect the effect of retroactive application of the units-of-production method. See Note 11 for the effects of the change in depletion method on the individual quarters of 2002.

| | 2001 |
|---|---|
| | ---- |
| Pro forma amounts assuming change is applied retroactively: | |

| | | |
|---|---|---|
| Net income | $ | 164,893 |
| | | ====== |
| Per investor partner unit (1,407.0 units) | $ | 102.74 |
| | | ====== |

5. Liquidity - Managing General Partner

As of December 31, 2003, the Managing General Partner is in violation of several covenants pertaining to their Amended and Restated Revolving Credit Agreement due June 1, 2006 and their Senior Second Lien Secured Credit Agreement due October 15, 2008. Due to the covenant violations, the Managing General Partner is in default under their Amended and Restated Revolving Credit Agreement and the Senior Second Lien Secured Credit Agreement, and all amounts due under these agreements have been classified as a current liability on the Managing General Partner's balance sheet at December 31, 2003. The significant working capital deficit and debt being in default at December 31, 2003, raise substantial doubt about the Managing General Partner's ability to continue as a going concern.

Subsequent to December 31, 2003, the Board of Directors of the Managing General Partner announced its decision to explore a merger, sale of the stock or other transaction involving the Managing General Partner. The Board has formed a Special Committee of independent directors to oversee the sales process. The Special Committee has retained independent financial and legal advisors to work closely with the management of the Managing General Partner to implement the sales process. There can be no assurance that a sale of the Managing General Partner will be consummated or what terms, if consummated, the sale will be on.

6. Commitments and Contingent Liabilities

The Managing General Partner has the right, but not the obligation, to purchase limited partnership units should an investor desire to sell. The value of the unit is determined by adding the sum of (1) current assets less liabilities and (2) the present value of the future net revenues attributable to proved reserves and by discounting the future net revenues at a rate not in excess of the prime rate charged by Nations Bank, N.A. of Midland, Texas, plus one percent (1%), which value shall be further reduced by a risk factor discount of no more than one-third (1/3) to be determined by the Managing General Partner in its sole and absolute discretion.

The Partnership is subject to various federal, state and local environmental laws and regulations, which establish standards and requirements for protection of the environment. The Partnership cannot predict the future impact of such standards and requirements, which are subject to change and can have retroactive effectiveness. The Partnership continues to monitor the status of these laws and regulations.

6. Commitments and Contingent Liabilities - continued

As of December 31, 2003, the Partnership has not been fined, cited or notified of any environmental violations and management is not aware of any unasserted violations, which would have a material adverse effect upon capital expenditures, earnings or the competitive position in the oil and gas industry. However, the Managing General Partner does recognize by the very nature of its business, material costs could be incurred in the near term to bring the Partnership into total compliance. The amount of such future expenditures is not reliably determinable due to several factors, including the unknown magnitude of possible contaminations, the unknown timing and extent of the corrective actions which may be required, the determination of the Partnership's liability in proportion to other responsible parties and the extent to which such expenditures are recoverable from insurance or indemnifications from prior owners of Partnership's properties.

7. Related Party Transactions

A significant portion of the oil and gas properties in which the Partnership has an interest are operated by and purchased from the Managing General Partner. As provided for in the operating agreement for each respective oil and gas property in which the Partnership has an interest, the operator is paid an amount for administrative overhead attributable to operating such properties, with such amounts to Southwest Royalties, Inc. as operator approximating $23,100, $23,700 and $23,600 for the years ended December 31, 2003, 2002 and 2001, respectively. In addition, the Managing General Partner and certain officers and employees may have an interest in some of the properties that the Partnership also participates.

Southwest Royalties, Inc., the Managing General Partner, was paid an administrative fee of $12,000 during 2003, 2002 and 2001 for reimbursement of indirect general and administrative overhead expenses. The administrative fees are included in general and administrative expense on the statement of operations.

Receivables from Southwest Royalties, Inc., the Managing General Partner, of approximately $43,600 and $39,500 are from oil and gas production, net of lease operating costs and production taxes, as of December 31, 2003 and 2002, respectively.

8. Major Customers

No material portion of the Partnership's business is dependent on a single purchaser, or a very few purchaser, where the loss of one would have a material adverse impact on the Partnership. Three purchasers accounted for 91% of the Partnership's total oil and gas production during 2003: Plains Marketing LP for 60%, Duke Energy Field Services

LP 18% and Navajo Refining Company, Inc. for 13%. Three purchasers accounted for 95% of the Partnership's total oil and gas production during 2002: Plains Marketing LP for 59%, Duke Energy Field Services LP for 19% and Navajo Refining Company, Inc. for 17%. Three purchasers accounted for 93% of the Partnership's total oil and gas production during 2001: Plains Marketing LP for 58%, Duke Energy Field Services for 21% and Navajo Refining Company, Inc. for 14%. All purchasers of the Partnership's oil and gas production are unrelated third parties. In the event this purchaser were to discontinue purchasing the Partnership's production, the Managing General Partner believes that a substitute purchaser or purchasers could be located without undue delay. No other purchaser accounted for an amount equal to or greater than 10% of the Partnership's total oil and gas production.

9. Subsequent Event

Subsequent to December 31, 2003, the Managing General Partner announced that its Board of Directors had decided to explore a merger or sale of the stock of the Company. The Board formed a Special Committee of independent directors to oversee the sale process. The Special Committee retained independent financial and legal advisors to work closely with management to implement the sale process.

On May 3, 2004, the Managing General Partner entered into a cash merger agreement to sell all of its stock to Clayton Williams Energy, Inc. The cash merger price is being negotiated, but is expected to be approximately $45 per share. The transaction, which is subject to approval by the Managing General Partner's shareholders, is expected to close no later than May 21, 2004.



10. Estimated Oil and Gas Reserves (unaudited)

The Partnership's interest in proved oil and gas reserves is as follows:

| | Oil (bbls) | Gas (mcf) |
|---|---|---|
| Total Proved - | | |
| January 1, 2001 | 110,000 | 242,000 |
| Revisions of estimates in | (22,000) | 26,000 |

| | | |
|---|---|---|
| place | | |
| Production | (9,000) | (23,000) |
| December 31, 2001 | 79,000 | 245,000 |
| Production | 17,000 | 13,000 |
| Revisions of estimates in place | (8,000) | (22,000) |
| December 31, 2002 | 88,000 | 236,000 |
| Production | (9,000) | (18,000) |
| Revisions of estimates in place | 1,000 | 48,000 |
| December 31, 2003 | 80,000 | 266,000 |
| Proved developed reserves - | | |
| December 31, 2001 | 79,000 | 245,000 |
| December 31, 2002 | 88,000 | 236,000 |
| December 31, 2003 | 80,000 | 266,000 |

All of the Partnership's reserves are located within the continental United States.

Southwest Developmental Drilling Fund 92-A, L.P.
(a Delaware limited partnership)

Notes to Financial Statements

10. Estimated Oil and Gas Reserves (unaudited) - continued

*Ryder Scott Company, L.P. prepared the reserve and present value data for the Partnership's existing properties as of January 1, 2004. The reserve estimates were made in accordance with guidelines established by the Securities and Exchange Commission pursuant to Rule 4-10(a) of Regulation S-X. Such guidelines require oil and gas reserve reports be prepared under existing economic and operating conditions with no provisions for price and cost escalation except by contractual arrangements.

Oil price adjustments were made in the individual evaluations to reflect oil quality, gathering and transportation costs. The results of the reserve report as of January 1, 2004, 2003 and 2002 are an average price of $31.76, $29.67 and $18.90 per barrel, respectively.

Gas price adjustments were made in the individual evaluations to reflect BTU content, gathering and transportation costs and gas processing and shrinkage. The results of the reserve report as of January 1, 2004, 2003 and 2002 are an average price of $5.30, $4.49 and $2.34 per Mcf, respectively.

The evaluation of oil and gas properties is not an exact science and inevitably involves a significant degree of uncertainty, particularly with respect to the quantity of oil or gas that any given property is capable of producing. Estimates of oil and gas reserves are based on available geological and engineering data the extent and quality of which may vary in each case and, in certain instances, may prove to be inaccurate. Consequently, properties may be depleted more rapidly than the geological and engineering data have indicated.

Unanticipated depletion, if it occurs, will result in lower reserves than previously estimated; thus an ultimately lower return for the Partnership. As new data is gathered during the subsequent year, the engineer must revise his earlier estimates. A year of new information, which is pertinent to the estimation of future recoverable volumes, is available during the subsequent year evaluation. In applying industry standards and procedures, the new data may cause the previous estimates to be revised. This revision may increase or decrease the earlier estimated volumes. Pertinent information gathered during the year may include actual production and decline rates, production from offset wells drilled to the same geologic formation, increased or decreased water production, workovers, and changes in lifting costs, among others. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered.

The Partnership has reserves, which are classified as proved developed. All of the proved reserves are included in the engineering reports, which evaluate the Partnership's present reserves.



10. Estimated Oil & Gas Reserves (unaudited) - continued

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2003, 2002 and 2001 is presented below:

| | 2003 | 2002 | 2001 |
|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| Future cash inflows | $ | 3,955,000 | 3,682,000 | 2,059,000 |
| Production, development and abandonment costs | | 2,113,000 | 1,945,000 | 1,334,000 |
| Future net cash flows | | 1,842,000 | 1,737,000 | 725,000 |
| 10% annual discount for estimated timing of cash flows | | 767,000 | 680,000 | 260,000 |
| Standardized measure of discounted future net cash flows | $ | 1,075,000 | 1,057,000 | 465,000 |

The principal sources of change in the standardized measure of discounted future net cash flows for the years ended December 31, 2003, 2002 and 2001 are as follows:

| | | 2003 | 2002 | 2001 |
|---|---|---|---|---|
| Sales of oil and gas produced, net of production costs | $ | (190,000) | (150,000) | (201,000) |
| Changes in prices and production costs | | 94,000 | 549,000 | (1,178,000) |
| Changes of production rates (timing) and others | | (69,000) | (12,000) | 177,000 |
| Revisions of previous quantities estimates | | 78,000 | 159,000 | (69,000) |
| Accretion of discount | | 105,000 | 46,000 | 158,000 |
| Discounted future net cash flows - Beginning of year | | 1,057,000 | 465,000 | 1,578,000 |
| End of year | $ | 1,075,000 | 1,057,000 | 465,000 |

Future net cash flows were computed using year-end prices and costs that related to existing proved oil and gas reserves in which the

Partnership has mineral interests.

Southwest Developmental Drilling Fund 92-A, L.P.
(a Delaware limited partnership)

Notes to Financial Statements

11. Selected Quarterly Financial Results - (unaudited)

| | Quarter | | | |
|---|---|---|---|---|
| | First | Second | Third | Fourth |
| 2003: | | | | |
| Total revenues | $ 102,069 | 88,470 | 75,271 | 83,474 |
| Total expenses | 38,013 | 52,123 | 53,468 | 49,007 |
| Cumulative effect of SFAS No. 143 | (2,744) | - | - | - |
| Net income | $ 61,312 | 36,347 | 21,803 | 34,467 |
| Per limited partner unit amounts: | | | | |
| Net income before cumulative effect | $ 40.21 | 22.68 | 13.56 | 21.56 |
| Cumulative effect of SFAS No. 143 | (1.74) | - | - | - |
| Net income | $ 38.47 | 22.68 | 13.56 | 21.56 |

As discussed in Note 4, in 2002 the Partnership changed methods of accounting for depletion of capitalized costs from the units-of-revenue method to the units-of-production method. The 2002 quarterly financial results presented below reflect the change in depletion method effective as of January 1, 2002.

| | Quarter | | | |
|---|---|---|---|---|
| | First | Second | Third | Fourth |

| | | | | |
|---|---|---|---|---|
| 2002: | | | | |
| Total revenues | $ 53,515 | 70,937 | 76,111 | 74,799 |
| Total expenses | 37,583 | 34,294 | 40,738 | 42,166 |
| Net income before cumulative effect of a change in accounting principle | 15,932 | 36,643 | 35,373 | 32,633 |
| Cumulative effect on prior years (to December 31, 2001) of changing to a different depletion method | (3,000) | - | - | - |
| Net income | $ 12,932 | 36,643 | 35,373 | 32,633 |
| Per limited partner unit amounts: | | | | |
| Net income before cumulative effect of a change in accounting principle | $ 9.77 | 22.87 | 22.14 | 20.40 |
| Cumulative effect on prior years (to December 31, 2001) of changing to a different depletion method | (2.13) | - | - | - |
| Net income | $ 7.64 | 22.87 | 22.14 | 20.40 |

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

As of the year ended December 31, 2003, H.H. Wommack, III, President and Chief Executive Officer of the Managing General Partner, and Bill E. Coggin, Executive Vice President and Chief Financial Officer of the

Managing General Partner, evaluated the effectiveness of the Partnership's disclosure controls and procedures. Based on their evaluation, they believe that:

> The disclosure controls and procedures of the Partnership were effective in ensuring that information required to be disclosed by the Partnership in the reports it files or submits under the Exchange Act was recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and
>
> The disclosure controls and procedures of the Partnership were effective in ensuring that material information required to be disclosed by the Partnership in the report it filed or submitted under the Exchange Act was accumulated and communicated to the Managing General Partner's management, including its President and Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting
There has not been any change in the Partnership's internal control over financial reporting that occurred during the year ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, it internal control over financial reporting.

## Part III

### Item 10. Directors and Executive Officers of the Registrant

Management of the Partnership is provided by Southwest Royalties, Inc., as Managing General Partner. The names, ages, offices, positions and length of service of the directors and executive officers of Southwest Royalties, Inc. are set forth below. Each director and executive officer of the Managing General Partner serves for a term of one year.

| Name | Age | Position |
|---|---|---|
| H. H. Wommack, III | 48 | Chairman of the Board, President, Director and Chief Executive Officer |
| James N. Chapman(1) | 41 | Director |
| William P. Nicoletti(2) | 58 | Director |
| Joseph J. Radecki, Jr. (2) | 45 | Director |
| Richard D. Rinehart(1) | 68 | Director |
| John M. White(2) | 48 | Director |
| Herbert C. Williamson, III(1) | 55 | Director |
| Bill E. Coggin | 49 | Executive Vice President and Chief Financial Officer |
| J. Steven Person | 45 | Vice President, Marketing |

(1) Member of the Compensation Committee

(2) Member of the Audit Committee

H. H. Wommack, III has served as Chairman of the Board, President, Chief Executive Officer and a director since Southwest's founding in 1983. Since 1997 Mr. Wommack has served as President, Chief Executive Officer and Chairman of SRH, Southwest's former parent and current holder of 10% of its voting share capital. SRH holds an equity investment in Southwest and in Basic Energy Services. Since 1997 Mr. Wommack has served as chairman of the board of directors of Midland Red Oak Realty, Inc. Midland Red Oak Realty owns and manages commercial real estate properties, including shopping centers and office buildings, in secondary real estate markets in the Southwestern United States. From 1997 until December 2000, Mr. Wommack served as chairman of the board of directors of Basic Energy Services, Inc. and since December 2000 has continued to serve on Basic's board of directors. Basic provides certain well services for oil and gas companies. Prior to Southwest's formation, Mr. Wommack was a self-employed independent oil and gas producer engaged in the purchase and sale of royalty and working interests in oil and gas leases and the drilling of wells. Mr. Wommack graduated from the University of North Carolina at Chapel Hill and received his law degree from the University of Texas.

James N. Chapman has served as a director since April 19, 2002. Mr. Chapman is associated with Regiment Capital Advisors, LLC, which he joined in January 2003. Prior to Regiment, Mr. Chapman acted as a capital markets and strategic planning consultant with private and public companies, as well as hedge funds, across a range of industries. Prior to establishing an independent consulting practice, Mr. Chapman worked for The Renco Group, Inc. from December 1996 to December 2001. Prior to Renco, Mr. Chapman was a founding principal of Fieldstone Private Capital Group in August 1990. Prior to joining Fieldstone, Mr. Chapman worked for Bankers Trust Company from July 1985 to August 1990, most recently in the BT Securities capital markets area. Mr. Chapman serves as a member of the board of directors of Anchor Glass Container Corporation, Davel Communications, Inc., Coinmach Corporation, as well as a number of private companies.

William P. Nicoletti has served as a director since April 19, 2002. Mr. Nicoletti is Managing Director of Nicoletti & Company Inc., an investment banking and financial advisory firm he founded in 1991. He was previously a senior officer and head of the Energy Investment Banking Groups of E. F. Hutton & Company Inc. and Paine Webber, Incorporated. From March 1998 until June 1990 he was a managing director and co-head of Energy Investment Banking at McDonald Investments Inc. Mr. Nicoletti is a director and Chairman of the Audit Committee of Star Gas Partners, L.P., the nation's largest retail distributor of home heating oil and a major retail distributor of propane gas. He is also a director of MarkWest Energy Partners, L.P., a business engaged in the gathering and processing of natural gas and the fractionation and storage of natural gas liquids, and Russell-Stanley Holdings, Inc., a manufacturer and marketer of steel and plastic industrial containers. Mr. Nicoletti is a graduate of Seton Hall University and received an MBA degree from Columbia University Graduate School of Business.

Joseph J. Radecki, Jr. has served as a director since April 19, 2002. Mr. Radecki is currently a Managing Director in the Leveraged Finance Group of CIBC World Markets where he is principally responsible for the firm's financial restructuring and distressed situation advisory practice. Prior to joining CIBC World Markets in 1998, Mr. Radecki was an Executive Vice President and Director of the Financial Restructuring Group of Jefferies & Company, Inc. beginning in 1990. From 1983 until 1990, Mr. Radecki was First Vice President in the International Capital Markets Group at Drexel Burnham Lambert, Inc., where he specialized in financial restructurings and recapitalizations. Over the past fourteen years, Mr. Radecki has been integrally involved in over 120 transactions totaling nearly $50 billion in recapitalized securities. Mr. Radecki currently serves as a Director of RBX Corporation, a manufacturer of rubber and plastic foam and other polymer products. He previously served as a Director of Wherehouse Entertainment, Inc., a music and video specialty retailer, as Chairman of the Board of American Rice, Inc., an international rice miller and marketer, as a member of the Board of Directors of Service America Corporation, a national food service management firm, Bucyrus International, Inc., a mining equipment manufacturer, and ECO-Net, a non-profit engineering related network firm. Mr. Radecki graduated magna cum laude in 1980 from Georgetown University with a B.A. in Government.

Richard D. Rinehart has served as a director since April 19, 2002. Mr. Rinehart is a founding principal of PetroCap, Inc. and president of Kestrel Resources, Inc. PetroCap, Inc. provides investment and merchant banking services to a variety of clients active in the oil and gas industry. Kestrel Resources, Inc. is a privately owned oil and gas operating company. He served as Director of Coopers & Lybrand's Energy Systems and Services Division prior to the founding of Kestrel Resources, Inc. in 1992. Prior to joining Coopers & Lybrand, he was chief executive officer/founder of Dawn Information Resources, Inc., formed in 1986 and acquired by Coopers & Lybrand in early 1991. Mr. Rinehart served as CEO of Terrapet Energy Corporation during the period 1982 through 1986. Prior to the formation of Terrapet in 1982, he was employed as President of the Terrapet Division of E.I. DuPont de Nemours and Company. Before its acquisition by DuPont, he served as CEO and President of Terrapet Corp., a privately owned E & P company. Before the formation of Terrapet Corp. in 1972, he was manager of supplementary recovery methods and senior evaluation engineer with H. J. Gruy and Associates, Inc., Dallas, Texas.

John White has served as a director since April 19, 2002. Mr. White became an equity analyst for Harris Nesbitt Gerard following the acquisition by BMO Financial Group in 2003. He had joined BMO Nesbitt Burns in 1998, responsible for high yield research on oil, gas and energy companies. Previously, Mr. White worked at John S. Herold, Inc., an independent oil and gas research and consulting firm, where he was responsible for fixed income research on the oil and gas industry. His prior experience also included four years managing a portfolio of oil and gas loans for The Bank of Nova Scotia. Before entering financial services, Mr. White was with BP, where he worked in exploration and production for seven years. At BP, his experience was primarily in the basins of the Mid-Continent and Rocky Mountain regions. Mr. White is a graduate of The University of Oklahoma.

Herbert C. Williamson, III has served as a director since April 19, 2002. At present, Mr. Williamson is self-employed as a consultant. From March 2001 to March 2002 Mr. Williamson served as an investment banker with Petrie Parkman & Co. From April 1999 to March 2001 Mr. Williamson served as chief financial officer and from August 1999 to March 2001 as a director of Merlon Petroleum Company, a private oil and gas company involved in exploration and production in Egypt. Mr. Williamson served as executive vice president, chief financial officer and director of Seven Seas Petroleum, Inc., a publicly traded oil and gas exploration company, from March 1998 to April 1999. From 1995 through April 1998, he served as director in the Investment Banking Department of Credit Suisse First Boston. Mr. Williamson served as vice chairman and executive vice president of Parker and Parsley Petroleum Company, a publicly traded oil and gas exploration company (now Pioneer Natural Resources Company) from 1985 through 1995.

Bill E. Coggin has served as Vice President and Chief Financial Officer since joining the Managing General Partner in 1985. Previously, Mr. Coggin was Controller for Rod Ric Corporation, an oil and gas drilling company, and for C.F. Lawrence & Associates, a large independent oil and gas operator. Mr. Coggin received a B.S. in Education and a B.A. in Accounting from Angelo State University.

J. Steven Person has served as Vice President, Marketing since joining the Managing General Partner in 1989. Mr. Person began in the investment industry with Dean Witter in 1983. Prior to joining the Managing General Partner, Mr. Person was a senior wholesaler with Capital Realty, Inc. While at Capital Realty, he was involved in the syndication of mortgage based securities through the major brokerage houses. Mr. Person received a B.B.A. degree from Baylor University and an M.B.A. from Houston Baptist University.

Key Employees

Jon P. Tate, age 46, has served as Vice President, Land and Assistant Secretary of the Managing General Partner since 1989. From 1981 to 1989, Mr. Tate was employed by C.F. Lawrence & Associates, Inc., an independent oil and gas company, as land manager. Mr. Tate is a member of the Permian Basin Landman's Association.

R. Douglas Keathley, age 48, has served as Vice President, Operations of the Managing General Partner since 1992. Before joining us, Mr. Keathley worked as a senior drilling engineer for ARCO Oil and Gas Company and in similar capacities for Reading & Bates Petroleum Co. and Tenneco Oil Co.

In certain instances, the Managing General Partner will engage professional petroleum consultants and other independent contractors, including engineers and geologists in connection with property acquisitions, geological and geophysical analysis, and reservoir engineering. The Managing General Partner believes that, in addition to its own "in-house" staff, the utilization of such consultants and independent contractors in specific instances and on an "as-needed" basis allows for greater flexibility and greater opportunity to perform its oil and gas activities more economically and effectively.

Code of Ethics

Neither the Partnership nor the Managing General Partner has adopted a code of ethics for employees, or any principal executive officers, principal financial officers, principal accounting officers or the Board of Directors of the Managing General Partner. The Board of the Managing General Partner believes that the Partnership's existing internal control procedures and current business practices are adequate to promote ethical conduct and to deter wrongdoing on the part of these executives. The Managing General Partner of the Partnership intends to implement during 2004 a code of ethics that will apply to these executives. In accordance with applicable SEC rules, the code of ethics will be made publicly available.

Audit Committee

The current members of the Audit Committee of the Managing General Partner are William P. Nicoletti, John M. White and Joseph J. Radecki, Jr. The Board of Directors of the Managing General Partner has determined that Mr. Nicoletti, the Chairman of the Audit Committee, meets the definition of an "audit committee financial expert" under Item 401(h)(2) of Regulation S-K and has also determined that all of the members of the Audit Committee, including Mr. Nicoletti, meet the independence requirements of Section 10A(m)(3) of the Securities Exchange Act of 1934, as amended, and the rules and regulations promulgated thereunder.

Item 11. Executive Compensation

The Partnership does not employ any directors, executive officers or employees. The Managing General Partner receives an administrative fee for the management of the Partnership. The Managing General Partner received $12,000 during 2003, 2002 and 2001 as an administrative fee. The executive officers of the Managing General Partner do not receive any form of compensation, from the Partnership; instead, their compensation is paid solely by Southwest. The executive officers, however, may occasionally perform administrative duties for the Partnership but receive no additional compensation for this work.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

There are no investor partners other than as listed below, who own of record, or are known by the Managing General Partner to beneficially own, more than five percent of the Partnership's investor partner interests.

| Title of Class | Name and Address of Beneficial Owner | Amount and Nature of Beneficial Ownership | Percent of Class |
|---|---|---|---|
| Limited Partnership Units | John H. Beckerle, Estate Trust<br>2653 South Kihei Road<br>Unit 211<br>Kihei Maui, HI 96753 | 90 limited partnership units | 5.7% |

The Managing General Partner owns an eleven percent interest as a Managing General Partner. Through prior purchases, the Managing General Partner also owns 15.0 limited partner units, or .95% limited partner interest. The Managing General Partner total percentage interest ownership in the Partnership is 11.9%.

No officer or director of the Managing General Partner directly owns Units in the Partnership. There are no arrangements known to the Managing General Partner, which may at a subsequent date result in a change of control of the Partnership. Beneficial ownership is determined in accordance with the rules of the Securities and Exchange Commission and includes voting or investment power with respect to the limited partner units. To our knowledge, except under applicable community property laws or as otherwise indicated, the persons named in the table have sole voting and sole investment control with regard to all limited partner units beneficially owned. We are presenting ownership information as of December 31, 2003. A list of beneficial owners of limited partner units, known to the Managing General Partner, is as follows:

| Title of Class | Name and Address of Beneficial Owner | Amount and Nature of Beneficial Ownership | Percent of Class |
|---|---|---|---|
| Limited Partnership Interest | Southwest Royalties, Inc.<br>Managing General Partner<br>407 N. Big Spring | Directly Owns 15.0 Units | .95% |

| | | | |
|---|---|---|---|
| | Street<br>Midland, TX 79701 | | |
| Limited Partnership Interest | H. H. Wommack, III<br><br>Chairman of the Board, President, and CEO of Southwest Royalties, Inc., the Managing General Partner<br>407 N. Big Spring Street<br>Midland, TX 79701 | Indirectly Owns 15.0 Units | .95% |

There are no arrangements known to the Managing General Partner, which may at a subsequent date result in a change of control of the Partnership.

Item 13. Certain Relationships and Related Transactions

In 2003, the Managing General Partner received $12,000 as an administrative fee. This amount is part of the general and administrative expenses incurred by the Partnership.

In some instances the Managing General Partner and certain officers and employees may be working interest owners in an oil and gas property in which the Partnership also has a working interest. Certain properties in which the Partnership has an interest are operated by the Managing General Partner, who was paid approximately $23,100 for administrative overhead attributable to operating such properties during 2003.

The terms of the above transactions are similar to ones, which would have been obtained through arm's length negotiations with unaffiliated third parties.

Item 14. Principal Accountant Fees and Services

The following table presents fees for professional audit services rendered by KPMG, LLP for the audit of the Partnership's annual financial statements for the years ended December 31, 2003 and 2002 and fees billed for other services rendered by KPMG during those periods.

| For the Year Ended December 31, | 2003 | 2002 |
|---|---|---|
| Audit Fees | $9,056 | $ 4,763 |
| Audit Related Fees | - | |

| | | |
|---|---|---|
| Tax Fees | - | - |
| All Other Fees | - | - |
| TOTAL | $9,056 | $ 4,763 |

The Audit Committee of the Managing General Partner reviewed and approved, in advance, all audit and non-audit services provided by KPMG, LLP.

## Part IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a)(1) Financial Statements:

Included in Part II of this report --

Independent Auditors Report
Balance Sheet
Statement of Changes in Partners' Equity
Statement of Cash Flows
Notes to Financial Statements

(2) Schedules I through XIII are omitted because they are not applicable, or because the required information is shown in the financial statements or the notes thereto.

(3) Exhibits:

Exhibit 4(a): Certificate of Limited Partnership of Southwest Developmental Drilling Fund 92-A, L.P., dated May 5, 1992 (Incorporated by reference from Partnership's Form 10-K for the fiscal year ended December 31, 1992).

Exhibit 4(b): Agreement of Limited Partnership of Southwest Developmental Drilling Fund 92-A, L.P. dated May 5, 1992 (Incorporated by reference from Partnership's Form 10-K for the fiscal year ended December 31, 1992).

Exhibit 4(c): First Amendment to Amended and Restated Certificate of Limited Partnership of Southwest Developmental Drilling Fund 92-A. L.P., dated as of February 22, 1993 (Incorporated by reference from Partnership's Form 10-K for the fiscal year ended December 31, 1993).

Exhibit 4(d): Second Amendment to Amended and Restated Certificate of Limited Partnership of Southwest Developmental Drilling Fund 92-A. L.P., dated as of March 26, 1993 (Incorporated by reference from Partnership's Form 10-K for the fiscal year ended December 31, 1993).

Exhibit 4(e): Second Amended and Restated Certificate of Limited Partnership of Southwest Developmental Drilling Fund 92-A. L.P., dated as of January 12, 1994. (Incorporated by reference from Partnership's Form 10-K for the fiscal year ended December 31, 1993).

31.1 Rule 13a-14(a)/15d-14(a) Certification
31.2 Rule 13a-14(a)/15d-14(a) Certification
32.1 Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2 Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

(b) Reports on Form 8-K

No report on Form 8-K was filed during the quarter ended December 31, 2003.

## Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Partnership has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Southwest Developmental Drilling Fund 92-A, L.P.,
a Delaware limited partnership

By: Southwest Royalties, Inc., Managing General Partner

By: /s/ H. H. Wommack, III
-------------------------------------------------

H. H. Wommack, III, President

Date: May 12, 2004

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 dates indicated.

| | |
|---|---|
| /s/ H. H. Wommack, III | /s/ Bill E. Coggin |
| H. H. Wommack, III, Chairman of the Board, President, Director and Chief Executive Officer | Bill E. Coggin, Executive Vice President and Chief Financial Officer |
| Date: May 12, 2004 | Date: May 12, 2004 |
| /s/ William P. Nicoletti | /s/ James N. Chapman |
| William P. Nicoletti, Director | James N. Chapman, Director |
| Date: May 10, 2004 | Date: May 12, 2004 |
| /s/ Richard D. Rinehart | /s/ Joseph J. Radecki, Jr. |
| Richard D. Rinehart, Director | Joseph J. Radecki, Jr., Director |

| | |
|---|---|
| Date: May 12, 2004 | Date: May 12, 2004 |
| /s/ Herbert C. Williamson, III | |
| ------------------------------------------------ | ------------------------------------------------ |
| Herbert C. Williamson, III, Director | John M. White, Director |
| Date: May 11, 2004 | Date: |

SECTION 302 CERTIFICATION Exhibit 31.1

I, H.H. Wommack, III, certify that:

1. I have reviewed this annual report on Form 10-K of Southwest Developmental Drilling Fund 92-A, L.P.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: May 12, 2004

/s/ H. H. Wommack, III
H. H. Wommack, III
Chairman, President and Chief Executive Officer
of Southwest Royalties, Inc., the
Managing General Partner of
Southwest Developmental Drilling Fund 92-A, L.P.

SECTION 302 CERTIFICATION

Exhibit 31.2

I, Bill E. Coggin, certify that:

1. I have reviewed this annual report on Form 10-K of Southwest Developmental Drilling Fund 92-A, L.P.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: May 12, 2004

/s/ Bill E. Coggin
Bill E. Coggin
Executive Vice President
and Chief Financial Officer of
Southwest Royalties, Inc., the
Managing General Partner of
Southwest Developmental Drilling Fund 92-A, L.P.

Exhibit 32.1

CERTIFICATION PURSUANT TO
19 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Southwest Developmental Drilling Fund 92-A, L.P. (the "Company") on Form 10-K for the period ending December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, H.H. Wommack, III, Chief Executive Officer of the Managing General Partner of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Company.

Date: May 12, 2004

/s/ H.H. Wommack, III
H. H. Wommack, III
Chairman, President, Director and Chief Executive Officer
of Southwest Royalties, Inc., the

Managing General Partner of
Southwest Developmental Drilling Fund 92-A, L.P.

CERTIFICATION PURSUANT TO Exhibit 32.2
19 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Southwest Developmental Drilling Fund 92-A, L.P. (the "Company") on Form 10-K for the period ending December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Bill E. Coggin, Chief Financial Officer of the Managing General Partner of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Company.

Date: May 12, 2004

/s/ Bill E. Coggin
Bill E. Coggin
Executive Vice President
and Chief Financial Officer of
Southwest Royalties, Inc., the
Managing General Partner of
Southwest Developmental Drilling Fund 92-A, L.P.