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

FORM 10-K/A

[x] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2001.

OR

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Commission File Number 000-20872

ST. MARY LAND & EXPLORATION COMPANY
(Exact name of registrant as specified in its charter)

Delaware	41-0518430
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1776 Lincoln Street, Suite 1100, Denver, Colorado 80203
(Address of principal executive offices) (Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:
None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $.01 par value
(Title of Class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. 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]

The aggregate market value of 26,932,198 shares of voting stock held by non-affiliates of the Registrant, based upon the closing sale price of the common stock on March 12, 2002 of $19.93 per share as reported on the Nasdaq National Market System, was $536,758,706. Shares of common stock held by each director and executive officer and by each person who owns 10% or more of the outstanding common stock or who is otherwise believed by the Company to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of March 12, 2002, the registrant had 27,805,529 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III (Items 10, 11, 12 and 13) is incorporated by reference from the Registrant's definitive proxy statement relating to its 2002 annual meeting of stockholders to be filed within 120 days from December 31, 2001.

EXPLANATORY NOTE -- THIS AMENDMENT ON FORM 10-K/A TO THE REGISTRANT'S FORM 10-K FOR THE FISCAL YEAR ENDED DECEMBER 31, 2001 IS BEING FILED TO CORRECT DISCLOSURES APPEARING UNDER THE RISK FACTORS CAPTION OF ITEM 1, THE LIQUIDITY AND CAPITAL RESOURCES SECTION OF ITEM 7, AND THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS INCLUDED HEREIN WHICH PREVIOUSLY INCORRECTLY INDICATED THAT THE MAXIMUM LOAN AMOUNT UNDER THE REGISTRANT'S LONG-TERM REVOLVING CREDIT FACILITY AGREEMENT WITH A BANK GROUP IS $115 MILLION. THE CORRECT MAXIMUM LOAN AMOUNT UNDER THE CREDIT FACILITY AGREEMENT IS $200 MILLION, WITH A CURRENT STATED TOTAL BORROWING BASE OF $170 MILLION, AS REFLECTED IN THE CORRECTED DISCLOSURES IN THIS FORM 10-K/A. ALL OTHER INFORMATION CONTAINED IN THE ORIGINAL FORM 10-K REMAINS UNCHANGED.

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PART I

When we use the terms "St. Mary," "we," "us" or "our," we are referring to St. Mary Land & Exploration Company and its subsidiaries, unless the context otherwise requires. We have included technical terms important to an understanding of our business under "Glossary of Common Oil and Gas Terms". Throughout this document we make statements that are classified as "forward-looking". Please refer to the "Forward-Looking Statements" section of this document for an explanation of these types of assertions.

ITEM 1. BUSINESS

Background

St. Mary Land & Exploration Company is an independent energy company engaged in the exploration, development, acquisition and production of natural gas and crude oil. St. Mary was founded in 1908 and incorporated in Delaware in 1915. Our operations are focused in the following five core operating areas in the United States:

- the Mid-Continent region in western Oklahoma and northern Texas;
- the ArkLaTex region that spans northern Louisiana and portions of eastern Texas, Arkansas and Mississippi;
- the onshore Gulf Coast and offshore Gulf of Mexico;
- the Williston Basin in eastern Montana and western North Dakota; and
- the Permian Basin in eastern New Mexico and western Texas.

As of December 31, 2001, we had estimated proved reserves of approximately 23.7 MMBbls of oil and 241.2 Bcf of natural gas, or a total of 383.2 BCFE, 86% of which were proved developed and 63% of which were natural gas, with a PV-10 value of $363.8 million. For the year ended December 31, 2001, we produced 54.1 BCFE representing average daily production of 148.2 MMCFE per day.

We focus our resources in selected domestic basins where we believe that our expertise in geology, geophysics and drilling and completion techniques provides us with competitive advantages. We have assembled a balanced program of low-to-medium-risk development and exploitation projects to provide the foundation for steady growth. In addition, we have a portfolio of higher-risk higher-potential exploration projects that we believe could significantly increase our reserves and production. We measure and rank our investment decisions based on their risk-adjusted impact on per share value. In the past, we have sold selected assets when we believed attractive prices were available, and we will continue to evaluate such opportunities in the future.

We seek to develop our existing property base and acquire acreage with additional potential in our core areas. From January 1, 1999 through December 31, 2001, we participated in the drilling and recompletion of 622 gross wells with an average success rate of 83%. During that same period we added estimated proved reserves of 347 BCFE at an average finding cost of $1.15 per MCFE. Our average annual production replacement was 251% during this three-year period, and our production has grown at an average rate of 18% per year over the same time period.

As of December 31, 2001, we had an acreage position of 1,192,077 gross (539,658 net) acres of which 620,540 gross (347,432 net) acres were undeveloped. For 2002 we have budgeted capital expenditures of $104.0 million for ongoing development, exploitation and exploration programs in our core operating areas and $60.0 million for acquisitions of oil and gas properties and acreage.

Our principal offices are located at 1776 Lincoln Street, Suite 1100, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Business Strategy

Our objective is to build stockholder value through consistent economic growth in reserves and production that increase net asset value per share, cash flow per share and earnings per share. The principal elements of our strategy are as follows:

- Maintain Focused Geographic Operations. We focus on exploration, development and acquisition activities in five core operating areas where we have built a balanced portfolio of proved reserves, development drilling opportunities and higher-risk higher-potential exploration prospects. We believe that our leasehold position is a strategic asset. Our senior technical managers, each possessing over 20 years of experience, head up regional technical offices located near core properties and are supported by centralized administration in our Denver office. We believe that our long-standing presence, our established networks of local industry relationships and our acreage holdings in our core operating areas provide us with a competitive advantage. In addition, we believe that we can continue to expand our operations without the need to proportionately increase the number of employees.

- Continue Exploitation and Development of Existing Properties. We use our comprehensive base of geological, geophysical, engineering and production experience in each of our core operating areas to source prospects for our ongoing low-to-medium-risk development and exploitation programs. We conduct detailed geologic studies and use an array of technologies and tools including 2-D and 3-D seismic imaging, hydraulic fracturing and reservoir stimulation techniques, and specialized logging tools to enhance the potential of our existing properties. In 2001 we participated in the drilling and recompletion of 252 gross drilling wells with an 83% success rate.

- Pursue Higher-Risk Higher-Potential Exploration Projects. We have allocated approximately 15% of our 2002 drilling and exploration capital expenditures budget to higher-risk higher-potential exploration projects and unconventional gas projects. Our strategy is to test several of these prospects each year that in total have the potential to significantly increase our reserves. We seek to invest in a diversified mix of exploration projects and generally limit our capital exposure by participating with other experienced industry partners. We plan to test several of these prospects in the Gulf Coast region and Rocky Mountain area during 2002.

- Make Selective Acquisitions. We seek to make selective niche acquisitions of oil and gas properties that complement our existing operations, offer economies of scale and provide further development, exploitation and exploration opportunities based on proprietary geologic concepts. We believe that the focus on smaller,

negotiated transactions where we have specialized geologic knowledge or operating experience has enabled us to acquire attractively priced and under-exploited properties. In addition, we will pursue corporate acquisitions that we believe will be accretive. Examples of this type of acquisition include our 1999 Nance Petroleum Corporation and King Ranch Energy, Inc. acquisitions, both of which were completed for stock. We believe that 2002 will be a very active year for the divestiture of oil and gas properties by larger and/or financially leveraged industry participants. We have budgeted $60.0 million for acquisitions in 2002.

- Control Operations. We believe it is important to control geologic and operational decisions as well as the timing of those decisions. At December 31, 2001, we operated 58% of our properties on a volume basis and 54% on a PV-10 value basis. We are the operator of properties representing approximately 73% of our 2002 drilling capital budget.

- Maintain Financial Flexibility. Conservative use of financial leverage has long been a critical element of our strategy. We believe that maintaining a strong balance sheet is a significant competitive advantage that enables us to pursue acquisition and other opportunities, especially in weaker price environments. It also provides us with the financial resources to weather periods of volatile commodity prices or escalating costs.

Significant Developments Since December 31, 2000

- 2001 Acquisition of Oil and Gas Properties. In November 2001 St. Mary completed a $40.5 million acquisition of properties from Choctaw II Oil & Gas, Ltd. The properties are located in our Williston Basin core area and the Green River Basin in Wyoming and produce approximately 1,200 barrels of oil and 4,600 Mcf of gas per day.

- Increase in 2001 Year-End Reserves. As of December 31, 2001 proved reserves increased 9% from December 31, 2000 levels to 383.2 BCFE. St. Mary added 35.7 BCFE through acquisitions for cash and 78.6 BCFE from drilling activities. There were net downward revisions of previous reserves totaling 24.4 BCFE consisting of 32.1 BCFE due to price revisions, partially offset by 7.7 BCFE in positive performance revisions.

- 2001 Acquisition of Coalbed Methane Prospects. In 2001 we acquired leases covering 115,000 acres in which we own an average 92% working interest in the Hanging Woman Basin of Montana and Wyoming for prospective coalbed methane development. We have drilled an 18-well pilot program and are evaluating its results. We are also currently investigating permitting and environmental issues related to these prospects. We will be unable to determine the future potential of these prospects until we have completed the evaluation of our pilot program and have resolved all such permitting and environmental issues. An environmental public interest group has filed a lawsuit against the federal Bureau of Land Management seeking to cancel certain federal leases related to coalbed methane development in Montana, which could affect 46,000 of our 115,000 leased acres. We will monitor this lawsuit as part of our investigation of environmental issues related to these prospects.

- Senior Convertible Notes. In March 2002 we issued in a private placement a total of $100.0 million of our 5.75% senior convertible notes due 2022 with a 1/2% contingent interest provision. We received net proceeds, after deducting the initial purchasers' discount and estimated offering expenses payalbe by us, of $96.7 million. The Notes are general unsecured obligations and rank on a parity in right of payment with all our existing and future senior indebtedness and other general unsecured obligations, and are senior in right of payment with all our future subordinated indebtedness. The Notes are convertible into our common stock at a conversion price of $26.00 per share, subject to adjustment. We can redeem the Notes with cash in whole or in part at a repurchase price of 100% of the principal amount plus accrued and unpaid interest beginning on March 20, 2007. The note holders have the option of requiring us to repurchase the Notes for cash at 100% of the principal amount plus accrued and unpaid interest upon (1) a change in control of St. Mary or (2) on March 20, 2007, March 15, 2012 and March 15, 2017. On March 20, 2007 we may pay the repurchase price with cash, shares of our common stock or any combination of cash and our common stock. We are not restricted from paying dividends, incurring debt, or issuing or repurchasing our securities under the indenture for the Notes. There are no financial covenants in the indenture . We used a portion of the net proceeds from the Notes to repay our credit facility balance and will use the remaining net proceeds to fund a portion of our 2002 capital budget.

Major Customers

During 2001 sales to Transok Gas Company accounted for 12.0% and sales to BP Amoco accounted for 11.3% of our total oil and gas production revenue. During 2000 sales to BP Amoco accounted for 22.3% of our total oil and gas production revenue. During 1999 sales to Transok accounted for 13.3% of our total oil and gas production revenue.

Employees and Office Space

As of December 31, 2001, St. Mary had 179 full-time employees. None of our employees is subject to a collective bargaining agreement. We consider our relations with our employees to be good. We lease approximately 42,660 square feet of office space in Denver, Colorado for our executive and administrative offices, of which 8,730 square feet is subleased. We also lease approximately 14,990 square feet of office space in Tulsa, Oklahoma; approximately 11,740 square feet in Shreveport, Louisiana; approximately 7,500 square feet in Lafayette, Louisiana; and approximately 15,830 square feet in Billings, Montana.

Title to Properties

Substantially all of our working interests are held pursuant to leases from third parties. A title opinion is usually obtained prior to the commencement of drilling operations on properties. We have obtained title opinions or conducted a thorough title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens for current taxes, and other burdens that we believe do not materially interfere with the use of or affect the value of such properties. We perform only a minimal title investigation before acquiring undeveloped properties.

Competition

The oil and gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Our competitive position depends on our geological, geophysical and engineering expertise, our financial resources, and our ability to select, acquire and develop proved reserves. We believe that the locations of our leasehold acreage, our exploration, drilling and production capabilities and the experience of our management and that of our industry partners generally enable us to compete effectively in our core operating areas. However, we compete with a substantial number of major and independent oil and gas companies that have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also have refining operations, market refined products and generate electricity. We also compete with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Drilling equipment may be in short supply from time to time.

Government Regulations

Our business is subject to various federal, state and local laws and governmental regulations that may be changed from time to time in response to economic or political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, taxation and environmental protection. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas.

St. Mary's operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred, and the payment of such liabilities could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden environmental damages, but we do not believe that insurance coverage for environmental damage that occurs over time is available at a reasonable cost. Moreover, we do not believe that insurance coverage for the full potential liability that could be caused by sudden environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or may lose substantial portions of our properties in the event of certain environmental damages. St. Mary could incur substantial costs to comply with environmental laws and regulations.

Energy Regulations. With respect to federal energy regulation, the transportation and sale for resale of natural gas in interstate commerce have historically been regulated pursuant to several laws enacted by Congress and regulations promulgated under these laws by the Federal Energy Regulatory Commission, or the FERC, and its predecessor. In the past the federal government has regulated the prices at which gas could be sold. Congress removed all price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. However, Congress could reenact price controls in the future.

Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC

that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry that remain subject to the FERC's jurisdiction, most notably interstate natural gas transmission companies. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation.

The ultimate impact of the complex rules and regulations issued by the FERC since 1985 cannot be predicted. In addition, many aspects of these regulatory developments have not become final but are still pending judicial and final FERC decisions. We cannot predict what further action the FERC will take on these matters. Some of the FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress 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. We do not believe that we will be affected by any action taken materially differently than other natural gas producers and marketers with whom we compete.

Our sales of crude oil, condensate and natural gas liquids are currently not regulated and are made at market prices. However, in a number of instances the ability to transport and sell such products are dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum product pipelines. We do not believe that these regulations affect us any differently than other producers of these products.

Certain operations we conduct are on federal oil and gas leases that the Minerals Management Service administers. The MMS issues such leases through competitive bidding. These leases contain relatively standardized terms and require compliance with detailed MMS regulations and, for offshore leases, orders pursuant to the Outer Continental Shelf Lands Act, which are subject to change by the MMS. For offshore operations, lessees must obtain MMS approval for exploration plans and development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the MMS prior to the commencement of drilling. Lessees must also comply with detailed MMS regulations governing, among other things:

- engineering and construction specifications for offshore production facilities;
- safety procedures;
- flaring of production;
- plugging and abandonment of Outer Continental Shelf or OCS wells;
- calculation of royalty payments and the valuation of production for this purpose; and
- removal of facilities.

To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met. The cost of such bonds or other surety can be substantial, and we cannot assure that we can continue to obtain bonds or other surety in all cases. Under certain circumstances the MMS may require our operations on federal leases to be suspended or terminated.

Many of the states in which we conduct our oil and gas drilling and production activities regulate such activities by requiring, among other things, drilling permits and bonds and reports concerning operations. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing of waste material, plugging and abandonment of wells, restoration requirements, unitization and pooling of natural gas and oil properties and establishment of maximum rates of production from natural gas and oil wells. Some states prorate production to the market demand for oil and natural gas.

Environmental Regulations. Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from our operations.

Public interest in the protection of the environment has increased dramatically in recent years. Onshore and offshore drilling in some areas has been opposed by environmental groups and, in some areas, has been restricted. Legislation has also been proposed in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. To the extent laws are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental protection requirements that result in increased costs to the natural gas and oil industry (both onshore and offshore), our business and prospects could be adversely affected. We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us.

Violation of environmental laws and regulations can lead to the imposition of administrative, civil or criminal penalties; remedial obligations; and in some instances injunctive relief. In addition, violations of environmental laws or the discharge of hazardous materials or oil could result in liability for personal injuries, property damage, remediation and cleanup costs, and other environmental damages. As a result, substantial liabilities to third parties or governmental entities may be incurred, and the payment of such liabilities could have a material adverse effect on our financial condition and results of operations.

The Oil Pollution Act and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. Likewise, if the party fails to report a spill or to cooperate fully

in the cleanup, liability limits do not apply. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75 million in other damages. Few defenses exist to the liability imposed by OPA.

OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. As amended by the Coast Guard Authorization Act of 1996, OPA requires responsible parties of covered offshore facilities that have a worst case oil spill of more than 1,000 barrels to demonstrate financial responsibility in amounts ranging from at least $10 million in specified state waters to at least $35 million in federal outer continental shelf waters, with higher amounts of up to $150 million if a formal risk assessment indicates that a higher amount should be required based on specific risks posed by the operations or if the worst case oil-spill discharge volume possible at the facility may exceed the applicable threshold volumes specified under the final rule of the United States Department of the Interior Minerals Management Service. On August 11, 1998, the MMS enacted a final rule implementing these financial responsibility requirements. We do not anticipate that we will experience any difficulty in continuing to satisfy the MMS's requirements for demonstrating financial responsibility under OPA.

The Federal Water Pollution Control Act, also known as the Clean Water Act, imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The FWPCA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into coastal waters. Although the costs to comply with zero discharge mandates under federal or state law may be significant, the entire industry is expected to experience similar costs, and we believe that these costs will not have a material adverse impact on our results of operations or financial position. The United States Environmental Protection Agency has adopted regulations requiring certain oil and gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

The Comprehensive Environmental Response, Compensation, and Liability Act, also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons, including the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances under CERCLA, may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We generate both hazardous and nonhazardous solid wastes which are subject to requirements of the Federal Resource Conservation and Recovery Act and comparable state statutes. From time to time, the EPA has considered making changes in nonhazardous waste standards that would result in stricter disposal requirements for these wastes. Furthermore, it is possible that some wastes that

we generate that are currently classified as nonhazardous may be in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements. Changes in applicable regulations may result in an increase in our capital expenditures or operating expenses.

We currently own or lease, and have in the past owned or leased, onshore properties that for many years have been utilized for or associated with the exploration and production of oil and gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

Our operations are also subject to the Federal Clean Air Act and comparable state statutes. Amendments to the Clean Air Act adopted in 1990 contain provisions that may result in the imposition of increasingly stringent pollution control requirements with respect to air emissions from the operations of stationary and mobile source equipment. Such air pollution control requirements may include specific equipment or technologies, permits with emissions and operational limitations, pre-approval of new or modified projects or facilities producing air emissions, and similar measures. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties, and/or result in the limitation or cessation of construction or operation of certain air emission sources.

Risk Factors

Risks Related to Our Business

In addition to the other information set forth elsewhere in this Form 10-K, the following factors should be carefully considered when evaluating St. Mary.

Oil and natural gas prices are volatile, and an extended decline in prices would hurt our profitability and financial condition.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and gas properties depend heavily on prevailing market prices for oil and gas. We expect the markets for oil and gas to continue to be volatile. Any substantial or extended decline in the price of oil or gas would have a material adverse effect on our financial condition and results of operations. It could reduce our cash flow and borrowing capacity, as well as the value and the amount of our oil and gas reserves. Lower prices may also reduce the amount of oil and gas that we can economically produce.

Historically, the markets for oil and gas have been volatile, and they are likely to continue to be volatile. Wide fluctuations in oil and gas prices may result from relatively minor changes in the supply of and demand for oil and gas, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;

- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil or gas producing regions;
- the price and level of foreign imports;
- worldwide economic conditions;
- marketability of production;
- the level of consumer demand;

- the price, availability and acceptance of alternative fuels;
- the availability of pipeline capacity;
- weather conditions; and
- actions of federal, state, local and foreign authorities.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas. Declines in oil and gas prices would reduce our revenue and could also reduce the amount of oil and gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and gas prices do not necessarily move in tandem. Because approximately 63% of our proved reserves were natural gas reserves as of December 31, 2001, we are more susceptible to changes in natural gas prices.

A material portion of our production, revenues and cash flows are derived from one field.

Production from the Judge Digby Field accounted for approximately 16% of our total oil and gas production volumes during 2001. If the level of production from this field substantially declines other than through normal depletion over the expected reserve life, it could have a material adverse impact on our overall production levels and our revenues.

Our future success depends on our ability to replace reserves that we produce.

Our future success depends on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. As of December 31, 2001 our proved reserves would last for approximately 7.1 years if produced constantly at the 2001 rate of production. As a result, we must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. We must do this even during periods of low oil and gas prices. Without successful exploration or acquisition activities, our reserves, production and revenues will decline rapidly. In addition, approximately 14% of our total estimated proved reserves at December 31, 2001 were undeveloped. By their nature, undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We cannot assure you that we will be able to find and develop or acquire additional reserves at an acceptable cost.

Our producing property acquisitions carry significant risks.

Our recent growth is due in part to, and our growth strategy relies in part on, acquisitions of producing properties and exploration and production companies. Successful acquisitions require an assessment of a number of factors beyond our control. These factors include recoverable reserves, future oil and gas prices, operating costs and potential environmental and other liabilities. These assessments are inexact and their accuracy is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we do inspect a well, we may not always discover structural, subsurface or environmental problems that may exist or arise.

In connection with our acquisitions, we are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In addition, competition for producing oil and gas properties is intense and many of our competitors have financial and other resources substantially greater than those available to us. Therefore, we cannot assure you that we will be able to acquire oil and gas properties that contain economically recoverable reserves or that we will acquire such properties at acceptable prices.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. While it is our current intention to continue to concentrate on acquiring properties with development, exploitation and exploration potential located in our five core operating areas, we cannot assure you that in the future we will not decide to pursue acquisitions or properties located in other geographic regions. To the extent that such acquired properties are substantially different than our existing properties, our ability to efficiently realize the economic benefits of such transactions may be limited.

We may not be able to successfully integrate future property or corporate acquisitions.

We seek to make selective niche acquisitions of oil and gas properties, and we will pursue corporate acquisitions that we believe will be accretive. However, integrating acquired properties and businesses involves a number of special risks. These risks include the possibility that management may be distracted from normal business concerns by the need to integrate operations and systems and in retaining and assimilating additional employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results. We cannot assure you that we will be able to obtain adequate funds for future property or corporate acquisitions, successfully integrate our future property or corporate acquisitions or that we will realize any of the anticipated benefits of the acquisitions.

Substantial capital is required to replace and grow reserves.

We make, and will continue to make, substantial expenditures to find, acquire, develop and produce oil and natural gas reserves. Our capital expenditures for oil and gas properties were $182.9 million for 2001 and $125.2 million during 2000. We have budgeted total capital expenditures of $164.0 million in 2002. With the net proceeds from the sale of senior convertible notes

in March 2002 (see Item 7., Management's Discussion and Analysis), cash provided by operating activities and borrowings under our credit facility, we believe we will have sufficient cash to fund budgeted capital expenditures in 2002. If additional development or attractive acquisition opportunities arise, we may consider other forms of financing, including the public offering or private placement of equity or debt securities. However, if oil and gas prices decrease or we encounter operating difficulties that result in our cash flow from operations being less than expected, we may have to reduce the capital we can spend in future years, unless we raise additional funds through debt or equity financing. We cannot assure you that debt or equity financing, cash generated by operations or borrowing capacity will be available to us on acceptable terms to meet these requirements.

Future cash flows and the availability of financing will be subject to a number of variables, such as:

- our success in locating and producing new reserves;

- the level of production from existing wells; and

- prices of oil and natural gas.

Issuing equity securities to satisfy our financing requirements could cause substantial dilution to existing shareholders. Debt financing could lead to:

- a substantial portion of our operating cash flow being dedicated to the payment of principal and interest;

- us being more vulnerable to competitive pressures and economic downturns; and

- restrictions on our operations.

If our revenues were to decrease due to lower oil and natural gas prices, decreased production or other reasons, and if we could not obtain capital through our credit facility or otherwise, our ability to execute our development plans, replace our reserves or maintain production levels could be greatly limited.

We may not obtain a bank credit facility borrowing base redetermination that adequately meets our anticipated financing needs.

We have a long-term revolving credit facility with a bank group consisting of Bank of America, Comerica Bank-Texas and Wells Fargo Bank West. Under the facility, the maximum loan amount is $200.0 million. The amount actually available from time to time depends on a borrowing base that the lenders periodically redetermine based on the value of our oil and gas properties and other assets. The stated total borrowing base is currently $170.0 million. Since we pay commitment fees based on the unused portion of the borrowing base, we have limited the borrowing base that we have accepted to correspond with our actual funding requirements. The accepted borrowing base under the facility as of December 31, 2001 was $100.0 million.

Our next borrowing base redetermination date is scheduled to occur on or about April 15, 2002. We cannot assure you that the banks will agree to a borrowing base redetermination that is adequate for our anticipated financing needs.

If oil and gas prices decrease or exploration efforts are unsuccessful, we may be required to take additional writedowns.

There is a risk that we will be required to write down the carrying value of our oil and gas properties. This could occur when oil and gas prices are low or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results.

We follow the successful efforts accounting method. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed. All geological and geophysical costs on exploratory prospects are expensed as incurred. The capitalized costs of our oil and gas properties, on a field-by-field basis, may not exceed the estimated future net cash flows of that field. If capitalized costs exceed future net revenues we write down the costs of each such field to our estimate of fair market value. Unproved properties are evaluated at the lower of cost or fair market value. This type of charge will not affect our cash flow from operating activities, but it will reduce the book value of our stockholders' equity. We review the carrying value of our properties quarterly, based on prices in effect as of the end of each quarter or as of the time of reporting our results. Once incurred, a writedown of oil and gas properties is not reversible at a later date even if oil or gas prices increase. St. Mary incurred impairment and abandonment charges on proved and unproved properties of $4.7 million, $6.3 million and $10.6 million in 2001, 2000 and 1999, respectively.

Information concerning our reserves and future net revenue estimates is uncertain.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. Estimates of proved undeveloped reserves, which comprise a significant portion of our reserves, are by their nature uncertain. The reserve data included in this Annual Report on form 10-K is estimated. Although we believe these estimates are reasonable, actual production, revenues and reserve expenditures will likely vary from estimates, and these variances may be material.

Estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially.

Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. See "Business and Properties--Reserves."

In addition, you should not construe PV-10 value as the current market value of the estimated oil and natural gas reserves attributable to our properties. We have based the PV-10 value on prices and costs as of the date of the estimate, in accordance with applicable regulations, whereas actual future prices and costs may be materially higher or lower. For example, values of our reserves at December 31, 2001 were estimated starting with a calculated weighted average sales price of $19.84 per barrel of oil (NYMEX) and $2.65 per MMBtu of gas (Gulf Coast spot price), then adjusted for quality and basis differentials. During 2001 our realized gas prices were as high as $7.86 per Mcf and as low as $2.21 per Mcf. Many factors will affect actual future net cash flows, including:

- the amount and timing of actual production;
- supply and demand for oil and natural gas;
- curtailments or increases in consumption by natural gas purchasers; and
- changes in governmental regulations or taxation.

The timing of the production of oil and natural gas properties and of the related expenses affect the timing of actual future net cash flows from proved reserves and, thus, their actual present value. In addition, the 10% discount factor, which we are required to use to calculate PV-10 value for reporting purposes, is not necessarily the most appropriate discount factor given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject. As a result, our actual future net cash flows could be materially different from the estimates included in this Annual Report on form 10-K.

Our industry is highly competitive.

Major oil companies, independent producers, and institutional and individual investors are actively seeking oil and gas properties throughout the world, along with the equipment, labor and materials required to operate properties. Many of our competitors have financial and technological resources vastly exceeding those available to us. Many oil and gas properties are sold in a competitive bidding process in which we may lack technological information or expertise available to other bidders. We cannot be sure that we will be successful in acquiring and developing profitable properties in the face of this competition.

Exploration and development drilling may not result in commercially productive reserves.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas will be found. The cost of drilling and completing wells is often uncertain, and oil and gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;

- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- shortages in experienced labor;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

The prevailing prices of oil and gas also affect the cost of and the demand for drilling rigs, production equipment and related services.

We cannot assure you that the wells we drill will be productive or that we will recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry wells or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, nor can we be sure that our overall drilling success rate or our drilling success rate for activity within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our results of operations and financial condition. Also, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we cannot be sure that we will ever drill them or that we will produce oil or natural gas from them or any other potential drilling locations.

Our business is subject to operating hazards that could result in substantial losses.

Oil and gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic gas and other environmental hazards and risks. If any of these hazards occurs, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and penalties; and/or
- suspension of operations.

In addition, we may be liable for environmental damage caused by previous owners of property we own or lease. As a result, we may face substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses. An event that is not fully covered by insurance could have a material adverse effect on our financial condition and results of operations.

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us.

Other independent oil and gas companies' limited access to capital may change our exploration and development plans.

Many independent oil and gas companies have limited access to the capital necessary to finance their activities. As a result, some of the other working interest owners of our wells may be unwilling or unable to pay their share of the costs of projects as they become due. These problems could cause us to change, suspend or terminate our drilling and development plans with respect to the affected project.

Hedging transactions may limit our potential gains and involve other risks.

To manage our exposure to price risks in the marketing of our oil and natural gas, we enter into commodity price risk management arrangements from time to time with respect to a portion of our current or future production. While intended to reduce the effects of volatile oil and natural gas prices, these transactions may limit our potential gains if oil or natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;

- the counterparties to our futures contracts fail to perform under the contracts; or

- a sudden, unexpected event materially impacts oil or natural gas prices.

The terms of our hedging agreements may also require that we furnish cash collateral, letters of credit or other forms of performance assurance in the event that mark-to-market calculations result in settlement obligations by us to the counterparties, which would encumber our liquidity and capital resources.

Our industry is heavily regulated.

Federal, state and local authorities extensively regulate the oil and gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of oil and gas production. Noncompliance with statutes and regulations may lead to substantial penalties, and the overall regulatory burden on the industry increases the cost of doing business and, in turn, decreases profitability. State and local authorities regulate various aspects of oil and gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of oil and gas

properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment, and restoration. Federal authorities regulate many of these same activities for our drilling and production operations in federal offshore waters. To cover the various obligations of leaseholders in federal waters, federal authorities generally require that leaseholders have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of these bonds or other surety can be substantial, and we cannot assure you that we will be able to obtain bonds or other surety in all cases. Under some circumstances, federal authorities may require any of our operations on federal leases be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations.

We must comply with complex environmental regulations.

Our operations are subject to complex and constantly changing environmental laws and regulations adopted by federal, state and local governmental authorities where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, could have a material adverse effect on our business. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We could face significant liabilities to the government and third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, and we could have to spend substantial amounts on investigations, litigation and remediation. We cannot be sure that existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, will not materially adversely affect our results of operations and financial condition. As a result, we may face material indemnity claims with respect to properties we own or have owned.

Our business depends on transportation facilities owned by others.

The marketability of our oil and gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

We depend on key personnel.

Our success will continue to depend on the continued services of our executive officers and a limited number of other senior management and technical personnel with extensive experience and expertise in evaluating and analyzing producing oil and gas properties and drilling prospects, maximizing production from oil and gas properties and marketing oil and gas production. Loss of the services of any of these people could have a material adverse effect on our operations. We currently do not have employment agreements with our executive officers other than Mark Hellerstein, our Chief Executive Officer. We do not carry any key person life insurance policies.

Ownership of working interests, royalty interests and other interests by some of our officers and directors may create conflicts of interest.

As a result of their prior employment with another company with which St. Mary engaged in a number of transactions, Ronald D. Boone, the Executive Vice President and Chief Operating Officer and a director of St. Mary, and two other vice presidents of St. Mary own working interests and royalty interests in many of St. Mary's properties, which were earned as part of the prior employer's employee benefit programs. Those persons have no royalty participation in any new St. Mary properties.

Mr. Boone also owns 50% of Princeton Resources Ltd. and has a 33% interest in Baron Oil Corporation, entities that manage the oil and gas working and royalty interests which he acquired as a result of his prior employment. Although Mr. Boone does not manage these corporations, he may participate in any investment decisions made by them.

David C. Dudley, a director of St. Mary, is Operating Manager of Dudley & Associates, LLC, a closely-held oil and gas exploration and production firm. From time to time we may compete with Mr. Dudley's firm for acquisition, exploitation, exploration or development prospects.

As a result of these transactions and relationships, conflicts of interest may exist between these persons and us. Although these persons owe fiduciary duties to our stockholders and to us, we cannot assure you that conflicts of interest will always be resolved in our favor.

Risks Related to Our Common Stock

Our certificate of incorporation and bylaws have provisions that discourage corporate takeovers and could prevent shareholders from realizing a premium on their investment.

Our certificate of incorporation and bylaws contain provisions that may have the effect of delaying or preventing a change of control. These provisions, among other things, provide for noncumulative voting in the election of the board of directors and impose procedural requirements on stockholders who wish to make nominations for the election of directors or propose other actions at stockholders' meetings. These provisions, alone or in combination with each other and with the rights plan described below, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to shareholders for their common stock

On July 15, 1999, our board of directors adopted a stockholder rights plan. The plan is designed to enhance the board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect stockholders against attempts to acquire us by means of unfair or abusive takeover tactics. If the board of directors decides in accordance with its fiduciary obligations that the terms of a potential acquisition do not reflect the long-term value of St. Mary, under the plan the board of directors could allow the holder of each outstanding share of our common stock other than those held by the potential acquirer to purchase one additional share of our common stock with a market value of twice the exercise price. This prospective dilution to a potential acquirer would make the acquisition impracticable unless the terms were improved to the satisfaction of the board of directors. However, the existence of the plan may impede a takeover not supported by our board, including a takeover that may be desired by a majority of our stockholders or involving a premium over the prevailing stock price.

Our shares that are eligible for future sale may have an adverse effect on the price of our common stock.

At January 31, 2002 we had 27,777,338 share of common stock outstanding. Of the shares outstanding, approximately 26,904,006 shares were freely tradable without substantial restriction or the requirement of future registration under the Securities Act. In addition, as of that date, options to purchase 2,151,445 shares were outstanding, of which 1,378,403 were exercisable. These options are exercisable at prices ranging from $9.25 to $33.3125 per share. In connection with the private placement of the Notes, our executive officers and directors have entered into lock-up agreements under which they have agreed not to offer or sell any shares of our common stock or similar securities for a period of 90 days from March 7, 2002 without the prior written consent of the initial purchasers of the Notes. The initial purchasers may at any time waive the terms of these lock-up agreements. Sales of substantial amounts of common stock, or a perception that such sales could occur, and the existence of options or warrants to purchase shares of commons stock at prices that may be below the then current market price of the common stock could adversely affect the market price of the common stock and could impair our ability to raise capital through the sale of our equity securities.

Our Chairman of the Board and his extended family may be able to control us.

Thomas E. Congdon, our Chairman of the Board, and members of his extended family currently own approximately 18% of the outstanding shares of our common stock. While no formal arrangements exist, these extended family members may be inclined to act in concert with Mr. Congdon on matters related to control of St. Mary, including for example the election of directors or response to an unsolicited bid to acquire St. Mary. Accordingly, Mr. Congdon and his family may be able to control or influence matters presented to our stockholders.

We may not always pay dividends on our common stock.

Although we have paid cash dividends to stockholders every year since 1940 and we expect that our practice of paying dividends will continue, the payment of future dividends remains in the discretion of the board of directors and will continue to depend on our earnings, capital requirements, financial condition and other factors. In addition, the payment of dividends is subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholder's equity. The board of directors may determine in the future to reduce the current annual dividend rate of $0.10 per share or discontinue altogether the payment of dividends.

Cautionary Statement about Forward-Looking Statements

This Annual Report on Form 10-K includes certain statements that may be deemed to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that St. Mary's management expects, believes or anticipates will or may occur in the future are forward looking statements. Examples of forward-looking statements may include discussion of such matters as:

- The amount and nature of future capital, development and exploration expenditures;

- The drilling of wells;
- Reserve estimates and the estimates of both future net revenues and the present value of future net revenues that are included in their calculation;
- Future oil and gas production estimates;
- Repayment of debt;
- Business strategies;
- Expansion and growth of operations; and
- Other similar matters such as those discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations.

These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Such statements are subject to a number of assumptions, risks and uncertainties, including such factors as the volatility and level of oil and natural gas prices, uncertainties in cash flow, expected acquisition benefits, production rates and reserve replacement, reserve estimates, drilling and operating risks, competition, litigation, environmental matters, the potential impact of government regulations, and other matters discussed under the caption "Risk Factors", many of which are beyond our control. Readers are cautioned that forward-looking statements are not guarantees of future performance and that actual results or developments may differ materially from those expressed or implied in the forward-looking statements.

Glossary

The terms defined in this section are used throughout this Form 10-K.

2-D seismic or 2-D data. Seismic data that are acquired and processed to yield a two-dimensional cross-section of the subsurface.

3-D seismic or 3-D data. Seismic data that are acquired and processed to yield a three-dimensional picture of the subsurface.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to oil or other liquid hydrocarbons.

Bcf. Billion cubic feet, used herein in reference to natural gas.

BCFE. Billion cubic feet of gas equivalent. Gas equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

Behind pipe reserves. Estimated net proved reserves in a formation in which production casing has already been set in the wellbore but has not been perforated and production tested.

BOE. Barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive in an attempt to recover proved undeveloped reserves.

Dry hole. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Estimated net proved reserves. The estimated quantities of oil, gas and gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

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 gas in another reservoir, or to extend a known reservoir.

Fee land. The most extensive interest that can be owned in land, including surface and mineral (including oil and gas) rights.

Finding cost. Expressed in dollars per BOE. Finding costs are calculated by dividing the amount of total capital expenditures for oil and gas activities by the amount of estimated net proved reserves added during the same period (including the effect on proved reserves of reserve revisions).

Gross acres. An acre in which a working interest is owned.

Gross well. A well in which a working interest is owned.

Hydraulic fracturing. A procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability and porosity.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MMBbl. One million barrels of oil or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent.

MMBOE. One million barrels of oil equivalent.

Mcf. One thousand cubic feet.

MCFE. One thousand cubic feet of gas equivalent. Gas equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

MMcf. One million cubic feet.

MMCFE. One million cubic feet of gas equivalent. Gas equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

MMBtu. One million British Thermal Units. A British Thermal Unit is the heat required to raise the temperature of a one-pound mass of water one degree Fahrenheit.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

Net asset value per share. The result of the fair market value of total assets less total liabilities, divided by the total number of outstanding shares of common stock.

PV-10 value. The present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), 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%.

Productive well. A well that is producing oil or gas or that is capable of production.

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

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.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has previously been completed.

Reserve life. Expressed in years, represents the estimated net proved reserves at a specified date divided by forecasted production for the preceding 12-month period.

Royalty. The interest paid to the owner of mineral rights expressed as a percentage of gross income from oil and gas produced and sold unencumbered by expenses.

Royalty interest. An interest in an oil and gas property entitling the owner to shares of oil and gas production free of costs of exploration, development and production. Royalty interests are approximate and are subject to adjustment.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether such acreage contains estimated net proved reserves.

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

ITEM 2. PROPERTIES

Operations

St. Mary's exploration, development and acquisition activities are focused in five core operating areas: the Mid-Continent region; onshore Gulf Coast and offshore Gulf of Mexico; the ArkLaTex region; the Williston Basin in North Dakota and Montana; and the Permian Basin in west Texas and New Mexico. Information concerning each of our major areas of operations, based on our estimated proved reserves as of December 31, 2001, is shown below.

	Estimated Proved Reserves					
	Oil	Gas	MMCFE		PV-10	
	(MBbls)	(MMcf)	Amount	Percent	(In thousands)	Percent
Mid-Continent Region...........	1,203	119,062	126,281	33.0%	$ 126,219	34.7%
ArkLaTex Region................	1,295	40,940	48,711	12.7%	37,978	10.4%
Gulf Coast and Gulf of Mexico..	1,025	44,126	50,274	13.1%	63,594	17.5%
Williston Basin................	16,248	24,376	121,867	31.8%	101,930	28.0%
Permian Basin..................	3,898	12,727	36,114	9.4%	34,074	9.4%
Total..........................	23,669	241,231	383,247	100.0%	$ 363,795	100.0%

Mid-Continent Region. Since 1973 St. Mary has been active in the Mid-Continent region, where operations are managed by our 32-person Tulsa, Oklahoma office. We have ongoing exploration and development programs in the Anadarko Basin of Oklahoma and Texas. The Mid-Continent region accounted for 33% of our estimated proved reserves as of December 31, 2001, or 126.3 BCFE, 85% of which were proved developed and 94% of which were natural gas. We participated in drilling 88 gross wells in this region in 2001, including 30 wells operated by us, 83% of which were completed as producers.

St. Mary's development and exploration budget in the Mid-Continent region for 2002 totals $33.0 million. We plan to operate 28 drilling wells in the Mid-Continent region during 2002 and to utilize three to four drilling rigs throughout the year. Our 2002 budget also reflects participation in an additional 100 to 125 wells to be operated by other entities.

Anadarko Basin. Our long history of operations and proprietary geologic knowledge enables us to sustain economic development and exploration programs despite periods of adverse industry conditions. We are applying state of the art technology in hydraulic fracturing and innovative well completion techniques to accelerate production and associated cash flow from the region's tight gas reservoirs. We also continue to benefit from the continuing consolidation of operators in the basin. We periodically pursue attractive opportunities to acquire properties from companies that have elected to discontinue operations in this basin. The $31.6 million acquisition of properties from JN Exploration that closed in December 2000 is a good example of this type of opportunity.

Approximately one-half of the drilling activities for 2002 will be focused on low-to-medium-risk development in the Cromwell, Granite Wash, Osborne, Red Fork and Spiro formations. In addition, approximately one-half of our 2002 Mid-Continent capital budget is allocated to deeper, higher-potential wells in the lower Morrow formation below 19,000 feet at the NE Mayfield Field in Oklahoma and in various other fields within the Morrow and Springer formations at depths between 10,000 and 16,000 feet.

Carrier Prospect. Within its inventory of higher-risk higher-potential exploration prospects, St. Mary holds an aggregate 42% working interest in 5,700 acres in Leon County, Texas. Our Carrier Prospect acreage relates to a platform reef prospect located near the industry's prolific Cotton Valley pinnacle reef discovery and targets potentially larger platform reefs that we believe developed in the deeper waters of the basin during the Jurassic period. We plan to seek industry participation for an initial test well in 2002.

Arkoma Basin. In Coal County, Oklahoma, we have acquired a leasehold position of 5,700 net acres. In 2001, we spud five gross wells, all of which were completed as gas wells. The producing formations in this area include the Booch, Hartshorne, Wapanucka and the Cromwell, which is the deepest formation at approximately 6,700 feet. Our average working interest for these wells is 98%, and we anticipate drilling at least ten gross wells in this area in 2002. Initial production rates from the wells have varied from approximately 500 Mcf per day to 1,250 Mcf per day. We are also actively pursuing additional leasehold positions within this four township area both through leasing activity and the acquisition of producing properties.

In February 2002 we acquired oil and gas properties and an 89-mile gas gathering system in the Arkoma Basin from Merchant Resources #1 L.P. of Houston, Texas for $7.8 million in cash. The properties include undrilled locations and are expected to complement other St. Mary properties in the area. The properties currently produce an estimated 1,200 Mcf of gas and 65 barrels of oil per day.

Gulf Coast and Gulf of Mexico Region. St. Mary's presence in south Louisiana dates to the early 1900's when our founders acquired a franchise property in St. Mary Parish on the shoreline of the Gulf of Mexico. These 24,900 acres of fee lands yielded more than $5.5 million of gross oil and gas royalty revenue in 2001. Our onshore Gulf Coast and Gulf of Mexico presence increased significantly in 1999 with the acquisition of King Ranch Energy. This acquisition included 260,000 gross undeveloped acres (81,000 net acres) and a large 3-D seismic database. The Gulf Coast and Gulf of Mexico region accounted for 13% of our estimated proved reserves as of December 31, 2001, or 50.3 BCFE, 90% of which were proved developed and 88% of which were natural gas.

St. Mary's diverse activities in the onshore Gulf Coast and Gulf of Mexico are managed by our 16-person regional office in Lafayette, Louisiana and include ongoing development and exploration programs in multiple basins onshore south Louisiana as well as several offshore shallow-water Gulf of Mexico blocks. Advanced 3-D seismic imaging and interpretation techniques and extensive subsurface geological interpretations are revitalizing exploration and development activities in the Miocene trend along the Gulf Coast. Our exploration and development budget in the Gulf Coast and Gulf of Mexico region for 2002 is $18.0 million.

The Judge Digby Field is the largest field acquired in the King Ranch Energy acquisition and is located outside Baton Rouge, Louisiana in Point Coupee Parish. We have interests ranging from 12% to 20% in nine wells that are producing a total of 130 MMcf per day on a gross basis as of February 12, 2002. This ultra deep field produces from multiple Tuscaloosa reservoirs between 19,000 and 24,000 feet. The wells are characterized by high producing rates such as the Parlange #11 completed in 2000 at an initial rate of 92,000 Mcf per day. We believe this well had the highest initial production rate for a well ever completed onshore Louisiana. New drilling in this field is continuing with the completion of the Parlange #12 in the deepest field pay ever produced at Judge Digby with initial rates of 64,000 Mcf per day. The J. Wuertele #2 was also completed in 2001, at an initial rate of 45,000 Mcf per day. The J. Wuertele #3 was spud on November 15, 2001 and is currently drilling toward a projected total depth of 22,000 feet. In addition to the drilling activity, multiple

recompletions of several wells are anticipated in 2002 in this multi-pay geologically complex field.

In the Gulf of Mexico, we plan to test a large 3-D target at Matagorda 701 during 2002. Matagorda 701 is located 50 miles northeast of Corpus Christi, Texas in 110 feet of water. We also plan to test a large fault block on the east flank of the Matagorda 700 field in 2002.

Fee Lands. St. Mary owns 24,900 acres of fee lands and associated mineral rights in St. Mary Parish located approximately 85 miles southwest of New Orleans, Louisiana. Since the initial discovery on our fee lands in 1938, our cumulative oil and gas revenues, primarily landowner's royalties, from the Bayou Sale, Horseshoe Bayou and Belle Isle fields have exceeded $235 million. We currently lease 10,357 acres and have an additional 14,557 acres that are unleased. Our principal operators on the fee properties are BP Amoco, Cabot, ExxonMobil and Badger Petroleum. We have encouraged development drilling by our lessees, facilitated the origination of new prospects on acreage not held by production and stimulated exploration interest in deeper, untested horizons. A discovery at South Horseshoe Bayou in early 1998 and a subsequent successful confirmation well in early 1999 established that significant accumulations of gas are sourced and trapped at depths below 16,000 feet.

Centennial Project. St. Mary participated in a 51 square mile 3-D seismic survey over the Spindletop field near Beaumont, Texas, which was completed in 2001. Our partner group has leased or optioned approximately 19,000 acres within the seismic outline. We have a 21% working interest in this project, which is planned to be a multi-year exploration and development program. The partner group plans to drill several wells in this project in 2002.

ArkLaTex Region. St. Mary's operations in the ArkLaTex region are managed by our 18-person office in Shreveport, Louisiana. The ArkLaTex region accounted for 13% of our estimated proved reserves as of December 31, 2001, or 48.7 BCFE, 85% of which were proved developed and 84% of which were natural gas. In 1992, we acquired the ArkLaTex oil and gas properties of T. L. James & Company, Inc. as well as rights to over 6,000 square miles of proprietary 2-D seismic data in the region. Much of the Shreveport office's successful exploration and development programs have derived from niche acquisitions completed since 1992 totaling $18.2 million. These acquisitions have provided access to strategic holdings of undeveloped acreage and proprietary packages of geologic and seismic data, resulting in an active program of additional development and exploration.

Our holdings in the ArkLaTex region are comprised of interests in approximately 502 producing gross wells, including 98 wells operated by us; interests in leases totaling approximately 73,500 gross acres; and mineral servitudes totaling approximately 14,600 gross acres. Activities in the ArkLaTex region during 2001 focused on the search for new opportunities and potential analog fields as well as final development of several important field discoveries made by our geoscientists since 1994. We have expanded into southern Mississippi where the objective is to leverage our technical expertise in the Mississippi salt play. St. Mary participated with a 50% working interest in two successful wells in 2000 in the James Lime play in east Texas, where it completed the Jones #1 and Jones #2 wells as multi-lateral wells, each with initial production exceeding 4,000 Mcf per day. We will continue to be active in this play in 2002.

In 2002 we will continue to focus on the search for new opportunities and potential analog fields in which to apply our proprietary geologic models and production techniques. We anticipate participating in 30 gross wells in the ArkLaTex region and are the operator of properties representing approximately

75% of our 2002 $14 million drilling capital expenditures budget.

Williston Basin Region. Nance Petroleum Corporation, a wholly owned subsidiary of St. Mary, has conducted operations in the Williston Basin in eastern Montana and western North Dakota on our behalf since 1991, initially under a joint venture arrangement and subsequently as a wholly owned subsidiary. The Williston Basin region accounted for 32% of our estimated proved reserves as of December 31, 2001, or 121.9 BCFE, 87% of which were proved developed and 80% of which were oil.

Our office in Billings, Montana includes a 28-person staff, some of which have spent over 20 years and their entire careers in the Williston Basin. A significant portion of the exploration and development in the Williston Basin is based on the interpretation of 3-D seismic data. We have successfully used 3-D seismic imaging to delineate structure and porosity development in the Red River formation. Since 1991 we have successfully completed 30 out of 32 gross wells drilled and operated. Our prospect inventory continues to expand as results from current activity lead to additional areas to conduct 3-D seismic surveys. Seven 3-D surveys are planned for 2002, exceeding the number of surveys conducted in any prior year.

St. Mary spent $16 million on exploration and development in the Williston Basin in 2001. In November 2001 we completed a $40.5 million acquisition of properties from Choctaw II Oil & Gas, Ltd. The properties are located in our Williston Basin core area and the Green River Basin in Wyoming and produce approximately 1,200 barrels of oil and 4,600 Mcf of gas per day. Our 2002 Williston Basin exploration and development capital budget is $22.0 million. We plan to drill ten operated wells with working interests ranging from 60% to 100%. We are the operator of properties representing approximately 80% of our Williston Basin capital budget in 2002.

Permian Basin Region. The Permian Basin area covers a significant portion of eastern New Mexico and western Texas and is one of the major producing basins in the United States. The basin includes hundreds of oil fields undergoing secondary and enhanced oil recovery projects. 3-D seismic imaging of existing fields and advanced secondary recovery programs are substantially increasing oil recoveries in the Permian Basin. Our holdings in the Permian Basin resulted from a series of niche property acquisitions since 1995, which total $21.9 million. We believe that our Permian Basin operations provide us with a solid base of long-lived oil reserves, promising longer-term exploration and development prospects and the potential for secondary recovery projects. The Permian Basin region accounted for 9% of our estimated proved reserves as of December 31, 2001, or 36.1 BCFE, of which 81% were proved developed and 65% were oil.

St. Mary participated in drilling 12 gross wells in 2001 with a 100% success rate. The East Shugart Delaware Unit waterflood project was initiated in 2000. The initial response from the water injection is anticipated in 2002, and we are hopeful the East Shugart waterflood will be an analog to our successful Parkway Delaware Unit waterflood that increased production from 325 Bbl per day in 1996 when the property was aquired to 1,125 Bbl per day as of February 12, 2002.

Our Permian Basin capital budget for 2002 is $9.0 million. In addition to drilling four injection wells in the East Shugart Delaware waterflood, two Morrow test wells are planned in the Parkway field and six in-fill wells are planned at Ft. Chadbourne. The HJSA top lease on 30,450 acres in Ward County, Texas became effective on August 5, 2000 and at year-end 2001 was producing 2,800 MCFE per day net to St. Mary. 3-D seismic data over the 50 square mile

lease was reprocessed and is currently being evaluated. We believe opportunities will develop with respect to our non-operated 21.4% interest in this lease.

Other Areas. In 2001 we acquired leases covering 115,000 acres in which we own an average 92% working interest in the Hanging Woman Basin of Montana and Wyoming for prospective coalbed methane development. We have drilled an 18-well pilot program and are evaluating its results. We are also currently investigating permitting and environmental issues related to these prospects. We will be unable to determine the future potential of these prospects until we have completed the evaluation of our pilot program and have resolved all such permitting and environmental issues. An environmental public interest group has filed a lawsuit against the federal Bureau of Land Management seeking to cancel certain federal leases related to coalbed methane development in Montana, which could affect 46,000 of our 115,000 leased acres. We will monitor this lawsuit as part of our investigation of environmental issues related to these prospects.

Coalbed methane production is similar to our traditional natural gas production as to the physical producing facilities and the product produced. However, the subsurface mechanisms that allow the gas to move to the wellbore and the producing characteristics of coalbed methane wells are very different from traditional natural gas production. Unlike conventional gas wells, which require a porous and permeable reservoir, hydrocarbon migration and a natural structural and/or stratigraphic trap, the coalbed methane gas is trapped in the molecular structure of the coal itself until released by pressure changes resulting from the removal of in situ water. Frequently, coalbeds are partly or completely saturated with water. As the water is removed, internal pressures on the coal are decreased, allowing the gas to desorb from the coal and flow to the wellbore. Unlike traditional gas wells, new coalbed methane wells often produce water for several months and then, as the water production decreases, natural gas production increases as the coal seams de-water.

Coalbed methane gas production requires state permits for the use of well-site pits and evaporation ponds for the disposal of produced water. However, groundwater produced from the coal seams can generally be discharged into arroyos, surface waters, well-site pits and evaporation ponds without a permit if it does not exceed surface discharge permit levels, and if it meets state and federal primary drinking water standards. All of these disposal options require an extensive third-party water sampling and laboratory analysis program to ensure compliance with state permit standards. Where water of lesser quality is involved or the wells produce water in excess of the applicable volumetric permit limits, additional disposal wells would have to be drilled to re-inject the produced water back into deep underground rock formations.

We are also currently investigating other potential unconventional natural gas projects in the Rocky Mountains.

Acquisitions

In November 2001, we completed a $40.5 million acquisition from Choctaw II Oil & Gas, Ltd. of oil and gas properties located in our Williston Basin core area and the Green River Basin in Wyoming. In December 2000 we completed a $31.6 million acquisition of oil and gas properties in the Mid-Continent region from JN Exploration. Also in 2000 we completed $21.5 million of niche acquisitions in our other core areas. During the last five years we have completed over $171 million of acquisitions. For 2002 we have budgeted $60.0

million for property acquisitions. However, we have the financial capacity to commit substantially greater resources to purchases should additional opportunities be identified. In February 2002 we completed a $7.8 million acquisition of properties in the Arkoma Basin of the Mid-Continent region from Merchant Resources #1 L.P.

Reserves

The following table presents summary information with respect to the estimates of our proved oil and gas reserves for each of the years in the three-year period ended December 31, 2001, as prepared by both Ryder Scott Company, independent petroleum engineers, and us. For the periods presented, Ryder Scott Company evaluated properties representing approximately 80% of our total PV-10 value while we evaluated the remainder. The PV-10 values shown in the following table are not intended to represent the current market value of the estimated proved oil and gas reserves owned by St. Mary. Neither prices nor costs have been escalated, but prices include the effects of hedging contracts. You should read the following table along with the sections entitled "Risk Factors - Risks Related to Our Business - Information concerning our reserves and future net revenue estimates is uncertain".

	As of December 31,		
	2001	2000	1999
Proved Reserves Data:			
Oil (MBbls)	23,669	20,950	18,900
Gas (MMcf)	241,231	225,975	207,642
MMCFE	383,247	351,673	321,042
PV-10 value (in thousands) (1)	$ 363,795	$ 1,153,663	$ 351,016
Proved Developed Reserves	86%	87%	84%
Production Replacement	166%	168%	541%
Reserve Life (years) (2)	7.1	6.7	10.3

(1) PV-10 value as of December 31, 2001 was calculated using prices in effect at December 31, 2001 of $19.84 per barrel of oil (NYMEX) and $2.65 per MMBtu of gas (Gulf Coast spot price). Both of these prices were then adjusted for transportation and basis differentials. These prices were 26 % and 72 % lower, respectively, than prices used to calculate PV-10 value as of December 31, 2000.

(2) Reserve life represents the estimated proved reserves at the dates indicated divided by actual production for the preceding 12-month period. The value as of December 31, 1999 reflects the acquisition of King Ranch Energy in December 1999.

Production

The following table summarizes the average volumes of oil and gas produced from properties in which St. Mary held an interest during the periods indicated:

	Years Ended December 31,		
	2001	2000	1999
Operating Data:			
Net production:			
Oil (MBbls)	2,434	2,398	1,383
Gas (MMcf)	39,491	38,346	22,805
MMCFE	54,093	52,731	31,104
Average net daily production:			
Oil (Bbls)	6,667	6,551	3,790
Gas (Mcf)	108,195	104,769	62,478
MCFE	148,199	144,075	85,216
Average sales price (1):			
Oil (per Bbl)	$ 23.29	$ 23.53	$ 16.56
Gas (per Mcf)	$ 3.73	$ 3.44	$ 2.21
Additional per MCFE data:			
Lease operating expense	$ 0.75	$ 0.48	$ 0.44
Transportation costs	$ 0.04	$ 0.04	$ 0.03
Production taxes	$ 0.23	$ 0.21	$ 0.16
General and administrative	$ 0.22	$ 0.21	$ 0.29
Depreciation, depletion and amortization	$ 0.95	$ 0.76	$ 0.73

(1) Includes the effects of St. Mary's hedging activities. See "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Productive Wells

As of December 31, 2001, we had interests in 947 gross (319 net) productive oil wells and 1,396 gross (268 net) productive gas wells. Productive wells are either producing wells or wells capable of commercial production although currently shut in. One or more completions in the same wellbore are counted as one well. A well is categorized under state reporting regulations as an oil well or a gas well based upon the ratio of gas to oil produced when it first commenced production, and such designation may not be indicative of current production.

Drilling Activity

The following table sets forth the wells drilled and recompleted in which St. Mary participated during each of the three years indicated:

	Years Ended December 31,					
	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	48	14.49	40	17.37	26	10.45
Gas	154	33.28	107	24.94	105	22.26
Non-productive	31	7.13	31	9.38	14	5.75
	233	54.90	178	51.69	145	38.46
Exploratory:						
Oil	3	1.55	6	4.17	1	.20
Gas	9	1.84	11	3.63	12	3.84
Non-productive	7	2.56	8	4.32	9	2.56
	19	5.95	25	12.12	22	6.60
Farmout or non-consent	9	-	8	-	6	-
Total(1)	261	60.85	211	63.81	173	45.06

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(1) Does not include 12, 4 and 1 gross wells completed on St. Mary's fee lands during 2001, 2000 and 1999, respectively.

All of our drilling activities are conducted on a contract basis with independent drilling contractors. We do not own any drilling equipment.

Acreage

The following table sets forth the gross and net acres of developed and undeveloped oil and gas leases, fee properties, mineral servitudes and lease options held by St. Mary as of December 31, 2001. Undeveloped acreage includes leasehold interests that may already have been classified as containing proved undeveloped reserves.

	Developed Acres (1)		Undeveloped Acres (2)		Total	
	Gross	Net	Gross	Net	Gross	Net
Arkansas	2,255	399	167	28	2,422	427
Louisiana	98,588	33,493	41,837	13,818	140,425	47,311
Montana	43,135	21,869	191,747	144,870	234,882	166,739
New Mexico	7,280	2,196	1,320	913	8,600	3,109
North Dakota	55,464	22,080	136,511	67,592	191,975	89,672
Oklahoma	193,443	44,728	53,883	18,940	247,326	63,668
Texas	136,460	48,080	119,252	38,896	255,712	86,976
Wyoming	12,209	3,318	48,415	38,693	60,624	42,011
Other (3)	2,501	346	8,083	4,884	10,584	5,230
	551,335	176,509	601,215	328,634	1,152,550	505,143
Louisiana Fee Properties	10,357	10,357	14,557	14,557	24,914	24,914
Louisiana Mineral Servitudes	9,845	5,360	4,768	4,241	14,613	9,601
	20,202	15,717	19,325	18,798	39,527	34,515
Total	571,537	192,226	620,540	347,432	1,192,077	539,658

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(1) Developed acreage is acreage assigned to producing wells for the spacing unit of the producing formation. Developed acreage in certain of St. Mary's properties that include multiple formations with different well spacing requirements may be considered undeveloped for certain formations, but have only been included as developed acreage in the presentation above.

(2) Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains estimated proved reserves.

(3) Includes interests in Alabama, Colorado, Kansas, Mississippi, South Dakota, Utah and Washington. St. Mary also holds an overriding royalty interest in an additional 44,388 gross acres in Utah.

Item 3. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. As of this date, no legal proceedings are pending against us that individually or collectively could have a material adverse effect upon our financial condition or results of operations.

A lawsuit has been filed in the Federal District Court in Montana by an environmental public interest group seeking the cancellation of all federal leases related to coalbed methane development issued in the State of Montana since January 1, 1997 on the grounds of an alleged failure of the federal Bureau of Land Management to comply with federal environmental laws. The lawsuit potentially affects 46,000 acres subject to federal leases of the 115,000 acres in our Hanging Woman Basin coalbed methane project. While we have not been made a party to the lawsuit and while we believe upon the basis of information presently available to us that the applicable environmental laws have been complied with, there is no assurance of the outcome of the lawsuit and therefore there is no assurance that it will not adversely affect our coalbed methane prospect. However, even if the Montana federal leases become unavailable, we anticipate continuing with the Hanging Woman Basin prospect in Wyoming and obtaining additional non-federal leases in Montana.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the fourth quarter of 2001.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the names, ages and positions held by St. Mary's executive officers as of January 31, 2002.

Name	Age	Position
Thomas E. Congdon	75	Chairman of the Board
Mark A. Hellerstein		President and Chief Executive Officer
Ronald D. Boone	54	Executive Vice President and Chief Operating Officer
Robert T. Hanley	55	Vice President - Business Development
Richard C. Norris	46	Vice President - Finance, Secretary and Treasurer
Milam Randolph Pharo	49	Vice President - Land and Legal
Garry A. Wilkening	51	Vice President - Administration and

		Controller
Douglas W. York	40	Vice President - Acquisitions and Engineering

Each of the executive officers has held the above positions for the past five years, with the exception of the following:

Robert T. Hanley has served as Vice President - Business Development since 2000. Prior to 2000, Mr. Hanley was Chief Financial Officer at Nance Petroleum Corporation and Panterra Petroleum.

Richard C. Norris has served as Vice President - Finance and Secretary since 1999. Prior to 1999, Mr. Norris was Vice President - Accounting and Administration and Treasurer. He joined St. Mary in 1982 as Corporate Controller.

Milam Randolph Pharo has served as Vice President - Land and Legal since 1998. Mr. Pharo joined St. Mary in 1996 as Vice President - Land and was previously in private practice as an attorney specializing in oil and gas matters since 1977.

Garry A. Wilkening joined St. Mary in 1993 as Corporate Controller. He was named Vice President - Administration in 1999. Prior to joining St. Mary, Mr. Wilkening was Corporate Controller for Fuel Resources Development Company, a subsidiary of Public Service Company of Colorado (now named Xcel Energy).

The executive officers of the Company serve at the pleasure of the board of directors and do not have fixed terms. Executive officers generally are elected at the regular meeting of the board immediately following the annual stockholders meeting. Any officer or agent elected or appointed by the board may be removed by the board whenever in its judgement the best interests of the Company will be served thereby without prejudice, however, to contractual rights, if any, of the person so removed.

There are no family relationships, first cousin or closer, between any executive officer and director. There are no arrangements or understandings between any officer and any other person pursuant to which that officer was elected.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information. St. Mary's common stock is traded on the Nasdaq National Market System under the symbol MARY. The range of high and low prices for the quarterly periods in 2001 and 2000, as reported by the Nasdaq National Market System and adjusted for the two-for-one stock split which was distributed on September 5, 2000 to shareholders of record as of the close of business on August 21, 2000, is set forth below:

Quarter Ended	High	Low
December 31, 2001	$22.20	$14.65
September 30, 2001	21.81	14.58
June 30, 2001	25.24	19.25
March 31, 2001	35.00	20.63
December 31, 2000	$34.31	$19.00
September 30, 2000	24.31	14.75
June 30, 2000	21.03	14.78
March 31, 2000	15.75	11.19

Holders. As of January 31, 2002, the number of record holders of St. Mary's common stock was 214. Management believes, after inquiry, that the number of beneficial owners of our common stock is in excess of 3,700.

Dividends. St. Mary has paid cash dividends to stockholders every year since 1940. Annual dividends of $0.10 per share were paid in each of the years 1998 through 2001. We expect that our practice of paying dividends on our common stock will continue, although the payment of future dividends on our common stock will continue to depend on our earnings, capital requirements, financial condition and other factors. In addition, the payment of dividends is subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholders' equity. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $2,795,000 in 2001 and $2,775,000 in 2000.

Restricted Shares. St. Mary issued 5,332,374 shares of its common stock to the shareholders of King Ranch, Inc. for the acquisition of King Ranch Energy, Inc. in December 1999. Those shares were subject to contractual restrictions on transfer until March 31, 2001, and are now freely transferable. We also issued 518,988 restricted shares of our common stock in connection with the acquisition of Nance Petroleum Corporation in June 1999. Those shares are restricted securities under federal securities laws and are also subject to contractual restrictions on transfer, which expire in increments over a three-year period from the date of acquisition. In addition, in connection with our March 2002 issuance of 5.75% senior convertible notes, our executive officers and directors entered into lock-up agreements under which they have agreed not to offer or sell any shares of our common stock or similar securities for a period of 90 days from March 7, 2002 without the prior written consent of the initial purchasers of the notes.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected consolidated financial data for St. Mary as of the dates and for the periods indicated. The financial data for each of the five years presented were derived from the Consolidated Financial Statements of St. Mary. The following data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations," which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with St. Mary's financial statements included elsewhere in this report.

	Years Ended December 31,				
	2001	2000	1999	1998	1997
	(In thousands, except per share data)				
Income Statement Data:					
Operating revenues:					
Oil and gas production	$ 203,973	$ 188,407	$ 73,387	$ 71,413	$ 76,603
Other	3,496	7,259	1,527	8,096	15,282
Total operating revenues	207,469	195,666	74,914	79,509	91,885
Operating expenses:					
Oil and gas production	55,000	38,461	19,574	17,770	16,097
Depletion, depreciation & amortization	51,346	40,129	22,574	24,912	18,366
Exploration	19,518	9,633	11,593	11,705	6,847
Impairment of proved properties	820	4,449	3,982	17,483	5,202
Abandonment and impairment of unproved properties	3,865	1,841	6,616	4,457	2,077
General and administrative	11,762	11,166	9,172	7,097	7,645
Unrealized derivative loss	1,573	-	-	-	-
Other	1,673	1,437	1,802	9,304	606
Total operating expenses	145,557	107,116	75,313	92,728	56,840
Income (loss) from operations	61,912	88,550	(399)	(13,219)	35,045
Non-operating (expense) income	376	737	75	(1,027)	(99)
Income tax (expense) benefit	(21,829)	(33,667)	406	5,415	(12,325)
Income (loss) from continuing operations	40,459	55,620	82	(8,831)	22,621
Gain on sale of discontinued operations, net of income taxes	-	-	-	34	488
Net income (loss)	$ 40,459	$ 55,620	$ 82	$ (8,797)	$ 23,109
Basic net income (loss) per common share:					
Income (loss) from continuing operations	$ 1.45	$ 2.00	$ -	$ (0.40)	$ 1.07
Gain on sale of discontinued operations	-	-	-	-	0.02
Basic net income (loss) per share	$ 1.45	$ 2.00	$ -	$ (0.40)	$ 1.09
Diluted net income (loss) per common share:					
Income (loss) from continuing operations	$ 1.42	$ 1.97	$ -	$ (0.40)	$ 1.05
Gain on sale of discontinued operations	-	-	-	-	0.02
Diluted net income (loss) per share	$ 1.42	$ 1.97	$ -	$ (0.40)	$ 1.07
Cash dividends per share	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10
Basic weighted average common shares outstanding	27,973	27,781	22,198	21,874	21,240
Diluted weighted average common shares outstanding	28,555	28,271	22,329	21,874	21,506

	Years Ended December 31,				
	2001	2000	1999	1998	1997
	(In thousands, except per share data)				

Balance Sheet Data (end of period):					
Working capital	$ 34,000	$ 40,639	$ 13,440	$ 9,785	$ 9,618
Net property and equipment	358,930	252,411	180,664	143,825	157,481
Total assets	436,989	321,895	230,438	184,497	212,135
Long-term obligations	64,000	22,000	13,000	19,398	22,607
Total stockholders' equity	286,117	250,136	188,772	134,742	147,932
Other Data:					
EBITDA (1)	$ 113,258	$ 128,679	$ 22,175	$ 11,693	$ 53,411
Net Cash provided by (used in)					
Operating activities	127,492	92,267	40,755	45,386	43,111
Investing activities	(159,075)	(112,868)	(22,243)	(36,982)	(67,477)
Financing activities	29,080	13,025	(12,138)	(7,695)	28,140
Capital and exploration expenditures, cash and noncash	182,863	125,184	91,184	57,855	89,213

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(1) EBITDA is defined as earnings before interest income and expense, income taxes, depreciation, depletion, amortization, and gain on sale of discontinued operations. EBITDA is a financial measure commonly used for St. Mary's industry and should not be considered in isolation or as a substitute for net income, cash flow provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles or as a measure of a company's profitability or liquidity. Because EBITDA excludes some, but not all, items that affect net income and may vary among companies, the EBITDA presented above may not be comparable to similarly titled measures of other companies.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

Overview

The year ended December 31, 2001 was volatile, not only for our industry, but also for the country as a whole. Spot gas prices per MMBtu ranged from $9.73 to $1.73. The NYMEX gas strip price fell by more than half. Oil prices dropped from a per barrel high of $32.00 to $17.50. The economy entered a recession that was further impacted by the events of September 11th and Enron's collapse. In our industry, rig utilization moved to effective capacity and resulted in substantial cost increases and diminished service quality. Operating costs also increased dramatically. Higher drilling, completion and operating costs and an overheated acquisition market made reserve additions costly. Through this turbulent environment we modestly grew production and maintained a strong balance sheet.

The industry enters 2002 with record gas in storage as well as excess OPEC capacity and a weakened economy. This suggests to us that we will encounter weaker prices in the near term. Subject to uncertainties specified in our cautionary statement about forward looking statements we project that results of operations for 2002 will reflect lower revenues and lower net income.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operation are based upon the information reported in our consolidated financial statements. The preparation of these financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our decisions on historical experience and various other sources that are believed to be reasonable under the circumstances. Actual results may differ from the estimates we calculated due to changing business conditions or unexpected circumstances. Policies we believe are critical to understanding our business operations and results of operations are detailed below. For additional information on our significant accounting policies you should see Note 1 and Note 11 in our accompanying consolidated financial statements.

Revenue recognition - We are engaged in the exploration, development, acquisition and production of natural gas and crude oil. Our revenue recognition policy is significant because our revenue is a key component of our results of operations and our forward looking statements contained in Liquidity and Capital Resources. We derive our revenue primarily from the sale of produced natural gas and crude oil. Revenue is recorded in the month our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. At the end of each period we make estimates of the amount of production delivered to the purchaser and the price we received. We use our knowledge of our properties, their historical performance, NYMEX and local spot market prices and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received are recorded in the month payment is received.

Oil and gas reserve quantities - Estimated reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, depreciation and impairment for our proved oil and gas properties. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing

economic and operating conditions. Future cash inflows and future production and development costs are determined by applying benchmark prices and costs, including transportation and basis differentials, in effect at the end of each period to the estimated quantities of oil and gas remaining to be produced at the end of that period. Expected cash flows are reduced to present value using a discount rate that depends upon the calculation for which the reserve estimates will be used. Reserve estimates are inherently imprecise and estimates of new discoveries are more imprecise than those of proved producing oil and gas properties. We expect that periodic reserve estimates will change in the future as additional information becomes available or as oil and gas prices and costs change. For any period, unknown circumstances could have caused us to calculate more or less depletion, depreciation or impairment. Changes in these calculations caused by changes in reserve quantities or net cash flows are recorded in the period that the reserve estimates changed.

Valuation of long-lived and intangible assets - Our property and equipment is recorded at cost. An impairment allowance is provided on unproved property when we determine that the property will not be developed. We evaluate the realizability of our proved producing and other long-lived assets whenever events or changes in circumstances indicate that an impairment may have occurred. Our impairment test compares the expected undiscounted future net revenues from a property using escalated pricing with the related net capitalized costs of the property at the end of each period. When the net capitalized costs exceed the undiscounted future net revenue of a property the cost of the property is written down to our estimate of fair value, which is determined by applying a 15% discount rate to future net revenues. Each company has its own criteria for acceptable internal rates of return, and those criteria can change overtime. Different pricing assumptions or discount rates would result in a different calculated impairment.

Income taxes - We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared, therefore we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns.

The following analysis contains additional discussion of management and accounting policies that are relevant to specific disclosures.

Results of Operations

The results of operations for 2000 include the full year impact of two significant acquisitions made during 1999. On June 1, 1999 St. Mary acquired Nance and Quanterra Alpha Limited Partnership and then acquired various other Williston Basin properties later in 1999 and into 2000. On December 17, 1999 St. Mary acquired King Ranch Energy, Inc now named St. Mary Energy Company.

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

	Years Ended December 31,		
	2001	2000	1999
	(In thousands, except per volume data)		
Oil and gas production revenues:			
Gas production	$ 147,292	$ 131,979	$ 50,482
Oil production	56,681	56,428	22,905
Total	$ 203,973	$ 188,407	$ 73,387
Net production:			
Gas (MMcf)	39,491	38,346	22,805
Oil (MBbls)	2,434	2,398	1,383
MMCFE	54,093	52,731	31,103
Average sales price (1):			
Gas (per Mcf)	$ 3.73	$ 3.44	$ 2.21
Oil (per Bbl)	$ 23.29	$ 23.53	$ 16.56
Oil and gas production costs:			
Lease operating expenses	$ 40,505	$ 25,567	$ 13,641
Transportation costs	2,321	1,817	893

Production taxes	12,174	11,077	5,040
Total	$ 55,000	$ 38,461	$ 19,574
Additional per MCFE data:			
Sales price (see Discussion under Accounting Matters)	$ 3.77	$ 3.57	$ 2.36
Lease operating expenses	(0.75)	(0.48)	(0.44)
Transportation costs	(0.04)	(0.04)	(0.03)
Production taxes	(0.23)	(0.21)	(0.16)
Operating margin	$ 2.75	$ 2.84	$ 1.73
Depletion, depreciation and amortization	$ 0.95	$ 0.76	$ 0.73
Impairment of proved properties	$ 0.02	$ 0.08	$ 0.13
General and administrative	$ 0.22	$ 0.21	$ 0.29

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(1) Includes the effects of the Company's hedging activities.

2001 to 2000 Comparison

Oil and Gas Production Revenues. Oil and gas production revenues increased $15.6 million, or 8% to a record $204.0 million in 2001 compared to $188.4 million in 2000. Revenue from gas production increased $15.3 million or 12%. This increase was a result of a gas production volume increase of 3% and an 8% increase in the average realized gas price to $3.73 per Mcf in 2001. Revenue from oil production increased $253,000. This increase resulted from an oil production volume increase of 1% offset by a 1% decrease in the average realized oil price to $23.29 per Bbl in 2001. Projections of pricing for oil and gas in 2002 lead us to believe that our average realized price for both gas and oil will decrease in 2002. Our share of revenue from wells completed in 2001 added $27.5 million of revenue and our December 2000 acquisition of JN Exploration properties added $11.5 million of revenue and average daily production of 7.4 MMCFE in 2001. Average net daily production increased to a new annual record of 148.2 MMCFE in 2001 compared to 144.1 MMCFE in 2000. Wells completed in 2001 offset 22.3 MMCFE of decline in average daily production from older properties.

St. Mary hedged approximately 34.6% or 841 MBbls of its oil production for 2001 and realized a $1.9 million decrease in oil revenue attributable to hedging compared to a $13.2 million decrease in 2000. Without these contracts we would have received an average price of $24.08 per Bbl in 2001 compared to $29.01 per Bbl in 2000. We also hedged 40.6% of our 2001 gas production or 17.6 million MMBtu and realized a $19.2 million decrease in gas revenue attributable to hedging compared to a $20.5 million decrease in gas revenues in 2000. Without these contracts we would have received an average price of $4.22 per Mcf for 2001 compared to $3.97 per Mcf in 2000. It is possible with the contracts we currently have in place and the December 31, 2001 projections of pricing for natural gas and oil in 2002 that we will record increases in oil and gas revenues attributable to hedging in 2002.

Oil and Gas Production Expenses. Oil and gas production expenses consist of lease operating expenses, production taxes and transportation expenses. Total production expenses increased $16.5 million, or 43% in 2001 to $55.0 million compared with $38.5 million in 2000. During 2001 we experienced a $4.9 million increase in non-recurring LOE most of which related to activity in the Williston Basin and the Gulf Coast Region. Williston Basin acquisitions in the last half of 2000 and in 2001 added $1.7 million of LOE. Recurring LOE from our JN Exploration acquisition properties represented $1.1 million of the increase and wells completed in 2001 added another $1.1 million. We experienced higher recurring LOE from wells completed in the Williston Basin, the Permian Basin and the Gulf Coast/Gulf of Mexico as a result of increased competition for limited availability of services and general cost inflation. Higher production taxes and transportation expenses resulting from higher oil and gas revenues account for $1.6 million of the increase. Total production costs per MCFE increased 40% to $1.02 for 2001 compared with $0.73 in 2000. An $0.18 per MCFE increase was due to the increase in non-recurring LOE plus LOE from acquisitions and wells completed in 2001. Another $0.02 per MCFE increase was due to increased production taxes and transportation expenses. The remaining increase is due to general cost inflation. This will be an area of concentration for us in 2002 as we attempt to decrease oil and gas production expenses in total and on a per MCFE basis.

Depreciation, Depletion, Amortization and Impairment. DD&A increased $11.2 million or 28% to $51.3 million in 2001 compared with $40.1 million in 2000. DD&A expense per MCFE increased 25% to $0.95 in 2001 compared to $0.76 in 2000. This increase reflects acquisitions and drilling results in 2000 and 2001 that added costs at a higher per unit rate. The DD&A per MCFE rate was further affected by downward adjustments to reserves due to pricing differences between December 31, 2001 and December 31, 2000.

St. Mary recorded an $820,000 impairment of proved oil and gas properties in 2001 compared with $4.4 million in 2000. Impairments in 2001 include a declining performance adjustment of $520,000 from the Thornton South prospect in Texas and various marginal well impairments.

Abandonment and impairment of unproved properties increased $2.0 million or 110% to $3.9 million in 2001 compared to $1.8 million in 2000. This increase is due to an increase in abandonment of expired leases in 2001 and the impairment of leasehold costs related to several exploratory dry holes.

Exploration. Exploration expense for 2001 increased $9.9 million or 103% to $19.5 million compared with $9.6 million in 2000. Percentages of total exploration expense are as follows:

	2001	2000
o Geological and geophysical expenses	19%	24%
o Exploratory dry holes	47%	21%
o Overhead and other expenses	34%	55%

Oil and gas exploration is imprecise, and success can be affected by numerous factors. Not every likely geological structure contains oil or natural gas. Even when oil or natural gas is discovered there are no guarantees that sufficient quantities can be produced to justify the completion of an exploratory well. In 2002 we have budgeted for geological and geophysical expenses and expect to incur overhead and other expenses in the pursuit of exploration, but we generally explore with an expectation of success.

General and Administrative. General and administrative expenses increased $596,000 or 5% to $11.8 million in 2001 compared to $11.2 million in 2000. Increases in compensation expense associated with increased personnel, our incentive plans and general cost inflation were offset by a $4.3 million increase in COPAS overhead reimbursements from operations and costs allocated to exploration expense

Income Taxes. Income tax expense totaled $21.8 million in 2001 resulting in an effective tax rate of 35.0% compared to $33.7 million in 2000 with an effective tax rate of 37.7%. The effective rate change from 2000 reflects decreased accrued state income taxes from marginal rate adjustments and a decrease in deferred federal income tax due to a 1% rate decrease from the highest federal marginal rate.

Net Income. Net income decreased to $40.5 million for 2001 compared to $55.6 million for 2000. An 8% increase in gas prices and a 3% increase in production volumes resulted in a $15.6 million increase in oil and gas production revenue. Increases in oil and gas production costs and DD&A of $27.8 million, a $5.2 million decrease from gains on sale of proved property and KMOC stock and a $9.9 million increase in exploration expense offset the increase in revenue and an $11.8 million decrease in income tax expense.

2000 to 1999 Comparison

Oil and Gas Production Revenues. St. Mary experienced a record year in 2000 for growth in oil and gas production revenues. This amount increased $115.0 million, or 157% to $188.4 million in 2000 compared to $73.4 million in 1999. Revenue from gas production increased $81.5 million or 161%. This increase was a result of a gas production volume increase of 68% and a 56% increase in the average realized gas price to $3.44 per Mcf in 2000. Revenue from oil production increased $33.5 million or 146%. This increase resulted from an oil production volume increase of 73% and a 42% increase in the average realized oil price to $23.53 per Bbl in 2000. Average net daily production increased to a 12-month record of 144.1 MMCFE in 2000 compared to 85.2 MMCFE in 1999. Our King Ranch Energy acquisition and Williston Basin acquisitions since June 1999 have added $97.0 million of revenue, not adjusted for hedge losses and average net daily production of 57.7 MMCFE over the prior year. A positive response to a waterflood at Parkway Delaware Unit combined with a successful gas well completion and pricing changes in the Permian Basin added 4.6 MMCFE to average net daily production and $10.9 million of revenue before hedge losses from 1999 to 2000.

St. Mary hedged approximately 55.4% or 1,329 MBbls of its oil production for 2000 and realized a $13.2 million decrease in oil revenue attributable to hedging compared to a $2.0 million decrease in 1999. Without these contracts we would have received an average price of $29.01 per Bbl in 2000 compared to $18.01 per Bbl in 1999. St. Mary also hedged 44.1% of its 2000 gas production or 18.6 million MMBtu and realized a $20.5 million decrease in gas revenue attributable to hedging compared to a $558,000 decrease in gas revenues in 1999. Without these contracts we would have received an average price of $3.97 per Mcf for 2000 compared to $2.19 per Mcf in 1999.

Gain (loss) on Sale of Proved Properties. Gain on sale of proved properties increased to $3.4 million in 2000 from a loss of $55,000 in 1999. St. Mary recognized a $1.8 million gain on the sale of shallow production from the HJSA top lease to the previous operator, a $1.0 million gain from the sale of various properties at auction and a $455,000 gain on the sale of our share of the Rock Penn Unit in west Texas.

Gain on sale of KMOC Stock. In February 2000 St. Mary exercised its option to convert its Khanty Mansiysk Oil Corporation production payment receivable into common stock of KMOC. In July 2000 we finalized a negotiated value for the receivable that equated to 21,583 shares of KMOC common stock under the terms of the original agreement. In December 2000 we sold 14,662 of these shares and recognized a net gain of $2.2 million.

Oil and Gas Production Expenses. Total production costs increased $18.9 million, or 96% in 2000 to $38.5 million compared with $19.6 million in 1999.

The KRE acquisition and Williston Basin acquisitions since June 1999 have added $15.3 million of production costs over 1999. These costs have also increased by $2.4 million in the Permian Basin as a result of waterflood activities. Total production costs per MCFE increased 16% to $0.73 for 2000 compared with $0.63 in 1999. We experienced a general $0.06 per MCFE increase in 2000 as a result of increased production taxes from increased revenue and an increase in lease operating costs. The additional $0.04 per MCFE increase was due to lease operating expenses and increased production taxes on increased revenue in the higher-cost Williston and Permian Basins.

Depreciation, Depletion, Amortization and Impairment. DD&A increased $17.6 million or 78% to $40.1 million in 2000 compared with $22.6 million in 1999. DD&A expense per MCFE increased 5% to $0.76 in 2000 compared to $0.73 in 1999. During the first three quarters of 2000 we had

reported a decrease in the DD&A rate per MCFE. This decrease was the result of a lower than average cost per unit from the KRE and Nance acquisitions, the addition of lower cost reserves from 1999 drilling activities and the effect of producing property impairments we recognized in the fourth quarter of 1999 and the first quarter of 2000. In the fourth quarter of 2000 two factors occurred that reversed this trend. First, we finalized the allocation of KRE acquisition costs as allowed by accounting standards. Second, year-end downward reserve adjustments for certain fields caused DD&A per MCFE to increase $0.08 for the year.

St. Mary recorded a $4.4 million impairment of proved oil and gas properties in 2000 compared with $4.0 million in 1999. Impairments in 2000 included a declining performance adjustment of $703,000 from the West Cameron Block 39 prospect in the Gulf of Mexico. Marginal well impairments included $656,000 from the Midland prospect in south Louisiana, $271,000 for the NE Collins prospect in Mississippi, $269,000 for the Heil II prospect in Texas and, in Oklahoma, $478,000 from the Buffalo Wallow prospect, $371,000 from the Boggy Creek prospect and $490,000 from the SW Weatherford prospect.

Abandonment and impairment of unproved properties decreased $4.8 million or 72% to $1.8 million in 2000 compared to $6.6 million in 1999. This decrease was due to a reduction in abandonment of expired leases in 2000 and the 1999 impairment of South Horseshoe Bayou.

Exploration. Exploration expense for 2000 decreased $2.0 million or 17% to $9.6 million compared with $11.6 million in 1999. Percentages of total exploration expense are as follows:

	2000	1999
o Geological and geophysical expenses	24%	12%
o Exploratory dry holes	21%	45%
o Overhead and other expenses	55%	43%

General and Administrative. General and administrative expenses increased $2.0 million or 22% to $11.2 million in 2000 compared to $9.2 million in 1999. Increases in general and administrative expenses resulting from the KRE and Nance acquisitions and charitable contributions of $809,000 were partially offset by a $2.8 million COPAS overhead reimbursement increase related to operations of the KRE properties and assumption of Permian Basin operations.

Income Taxes. Income tax expense totaled $33.7 million in 2000 resulting in an effective tax rate of 37.7% compared to a net benefit in 1999 of $406,000. The effective rate change from 1999 reflects a diminished effect from alternative fuel credits allowed under Internal Revenue Code Section 29 due to higher net income before tax, additional accrued state income taxes from income generated by the properties acquired from KRE and an increase in deferred federal income tax from a 1% rate increase to the highest federal marginal rate. During 2000 St. Mary determined that it would be more beneficial to forego the Section 29 credits generated from 1999 resulting in a net operating loss for 1999 that could be utilized in 2000 to reduce its current liability. This change also impacted the effective rate for 2000.

Net Income. Net income increased to $55.6 million for 2000 compared to $82,000 for 1999. A 56% increase in gas prices, a 42% increase in oil prices and a 73% increase in oil production volumes and a 68% increase in gas production volumes resulted in a record $115.0 million increase in oil and gas production revenue. A $3.5 million increase in gain on the sale of proved properties and the $2.2 million gain from the sale of KMOC stock contributed to the $120.8 million increase in total operating revenues. These revenue increases were offset by corresponding increases in oil and gas production costs and DD&A as well as a $34.1 million increase in income tax expense.

Liquidity and Capital Resources

Our primary sources of liquidity are the cash provided by operating activities, debt financing, sales of non-strategic properties and access to the capital markets. All of these sources can be impacted by significant fluctuations in oil and gas prices. An unexpected decrease in prices would reduce expected cash flow from operating activities, might reduce the borrowing base on our credit facility, could reduce the value of our non-strategic properties and historically has limited our industry's access to the capital markets.

We use cash for the acquisition, exploration and development of oil and gas properties and for the payment of debt obligations, trade payables and the payment of stockholder dividends. Exploration and development programs are generally financed from internally generated cash flow, debt financing and cash and cash equivalents on hand. In the event of an unexpected decrease in oil and gas prices, cash uses such as the acquisition of oil and gas properties and stockholder dividends are discretionary and can be reduced or eliminated. At any given point in time, we may be obligated to pay for commitments to explore for or develop oil and gas properties or incur trade payables. However, future obligations can be reduced or eliminated when necessary. We are currently only required to make interest payments on our debt obligations. An unexpected increase in oil and gas prices provides flexibility to modify our uses of cash flow.

We continually review our capital expenditure budget to reflect changes in current and projected cash flow, acquisition opportunities, debt requirements and other factors.

Cash Flow. St. Mary's net cash provided by operating activities increased $35.2 million or 38% to $127.5 million in 2001 compared to $92.3 million in 2000. The increase reflects a change between years of $22.5 million from the collection of receivables and a change between years of $15.4 million from increased accounts payable.

St. Mary's net cash provided by operating activities increased $51.6 million or 127% to $92.3 million in 2000 compared to $40.8 million in 1999. The increase reflects the effect of increases in oil and gas production and prices.

Net cash used in investing activities increased $46.2 million in 2001 to $159.1 million compared to $112.9 million in 2000. Total 2001 capital expenditures for cash, including acquisitions of oil and gas properties, increased $53.2 million or 45% to $170.5 million in 2001 compared to $117.3 million in 2000 due to an increase in drilling activity in 2001 offset by a decrease in cash expended for oil and gas property purchases.

Net cash used in investing activities increased $90.7 million in 2000 to $112.9 million compared to $22.2 million in 1999. Total 2000 capital expenditures for cash, including acquisitions of oil and gas properties, increased $77.6 million or 192% to $117.9 million in 2000 compared to $40.3 million in 1999 due to an increase in drilling activity in 2000 and an increase in cash expended for oil and gas property purchases.

Net cash provided by financing activities increased $16.1 million to $29.1 million in 2001 compared to $13.0 million in 2000. The increase is due to a net $42.0 million increase in long-term debt during 2001 compared to a $9.0 million increase in 2000 offset by a $4.4 million decrease in proceeds received from the sale of common stock related to our stock option programs. We also

repurchased $12.9 million of our common stock during 2001. We used our credit facility to fund the acquisition of properties from Choctaw and finance current operations.

Net cash provided by financing activities increased $25.2 million to $13.0 million in 2000 compared to cash used in financing activities of $12.1 million in 1999. The increase is due to a net $9.0 million increase in long-term debt during 2000 compared to a $9.8 million decrease in 1999 and a $6.8 million increase in proceeds received from the sale of common stock related to St. Mary's stock option programs. Proceeds from stock option programs were used to finance current operations and retire outstanding debt under the credit facility. During 2000 cash flow from operations and stock option programs was sufficient to reduce the outstanding debt balance to zero. The $22.0 million balance in outstanding debt at December 31, 2000 was a result of the JN acquisition.

St. Mary had $4.1 million in cash and cash equivalents and had working capital of $34.0 million as of December 31, 2001 compared to $6.6 million in cash and cash equivalents and working capital of $40.6 million as of December 31, 2000.

Senior Convertible Notes. In March 2002 we issued in a private placement a total of $100.0 million of our 5.75% senior convertible notes due 2022 with a 1/2% contingent interest provision. We received net proceeds of $96.7 million after deducting the initial purchasers' discount and estimated offering expenses payable by us. The Notes are general unsecured obligations and rank on a parity in right of payment with all our existing and future senior indebtedness and other general unsecured obligations, and are senior in right of payment with all our future subordinated indebtedness. The Notes are convertible into our common stock at a conversion price of $26.00 per share, subject to adjustment. We can redeem the Notes with cash in whole or in part at a repurchase price of 100% of the principal amount plus accrued and unpaid interest beginning on March 20, 2007. The note holders have the option of requring us to repurchase the Notes for cash at 100% of the principal amount plus accrued and unpaid interest upon (1) a change in control of St. Mary or (2) on March 20, 2007, March 15, 2012 and March 15, 2017. On March 20, 2007 we may pay the repurchase price with cash, shares of our common stock or any combination of cash and our common stock. We are not restricted from paying dividends, incurring debt, or issuing or repurchasing our securities under the indenture. There are no financial covenants in the indenture. We used a portion of the net proceeds from the Notes to repay our credit facility balance and will use the remaining net proceeds to fund a portion of our 2002 capital budget.

Credit Facility. At December 31, 2001 we had an unsecured long-term revolving credit facility with a bank group consisting of Bank of America, Comerica Bank-Texas and Wells Fargo Bank West. Under this facility, the maximum loan amount was $200.0 million. The amount actually available depends upon a borrowing base that the lenders periodically redetermine based on the value of our oil and gas properties and other assets. As of December 31, 2001 the stated total possible borrowing base was $170.0 million. However, since we pay commitment fees based on the unused portion of the borrowing base we have limited the borrowing base that we have accepted to correspond with our actual funding requirements. The accepted borrowing base was $100.0 million at December 31, 2001. See discussion below regarding the March 4, 2002 amendment to the credit facility. The facility has a maturity date of December 31, 2006, and includes a revolving period that matures on June 30, 2003 at which time all outstanding borrowings convert to a term loan payable in quarterly installments through the facility maturity date. We must comply with certain covenants including maintenance of stockholders' equity at a specified level, restrictions on additional indebtedness, sales of oil and gas properties, activities outside our ordinary course of business and certain merger transactions. Our next borrowing base redetermination is scheduled to occur on or before April 15, 2002.

As of December 31, 2001 and 2000, $64.0 million and $22.0 million, respectively, was outstanding under this credit agreement. These outstanding balances accrued interest at rates determined by St. Mary's debt to total capitalization ratio at our option of either (1) the higher of the federal funds rate plus 1/2% or the prime rate, or (2) LIBOR plus 3/4% when our debt to total capitalization is less than 30%, up to a maximum of either (a) the higher of the federal funds rate plus 3/4% or the prime rate plus 1/4%, or (b) LIBOR plus 1-3/8% when our debt to total capitalization is equal to or greater than 50%. At December 31, 2001 our debt to capitalization ratio as defined under the credit agreement was 22.4%.

In conjunction with the sale of the Notes discussed above we negotiated an amendment to the credit facility on March 4, 2002. Pursuant to the amendment, during the revolving period of the loan, loan balances will accrue interest at our option of either (1) the higher of the federal funds rate plus 1/2% or the prime rate, plus an additional 1/4% when our debt to capitalization ratio is greater than 50%, or (2) the LIBOR rate plus (a) 1% when our debt to total capitalization ratio is less than 30%, (b) 1 1/4% when our debt to capitization ratio is greater than or equal to 30% but less than 40%, (c) 1 3/8% when our debt to capitalization ratio is greater than or equal to 40% but less than 50%, or (d) 1 5/8% when our debt to capitalization ratio is greater than 50%. Proceeds from the Notes were used to repay the outstanding balance under the credit facility. Amounts repaid under the revolving loan provision of the credit facility will be available for reborrowing, subject to borrowing base limitations until June 30, 2003. Within 30 days after the closing of the Notes we must provide a pledge of collateral in favor of the banks to secure repayment of any future borrowings under the facility. Such collateral will consist primarily of security interests in the oil and gas properties of St. Mary and its subsidiaries.

Common Stock. At the annual stockholders meeting on May 23, 2001 the stockholders of St. Mary voted to increase the amount of authorized common shares to 100,000,000.

In July 2000 our board of directors approved a two-for-one stock split effected in the form of a stock dividend whereby one additional common share of stock was distributed for each common share outstanding. The stock split was distributed on September 5, 2000 to shareholders of record as of the close of business on August 21, 2000. All share and per share amounts for all periods presented herein have been restated to reflect this stock split.

In August 1998 our board of directors authorized a stock repurchase program whereby we may purchase from time-to-time, in open market transactions or negotiated sales, up to two million of our common shares. Through March 13, 2002 we had repurchased a total of 1,009,900 shares of St. Mary common stock under the program for $16.2 million at a weighted average price of $15.86 per share, net of put option sale premiums received. We anticipate that additional purchases of shares may occur as market conditions warrant. Any future purchases will be funded with internal cash flow and borrowings under our credit facility.

Capital and Exploration Expenditures. Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. The following table sets forth certain information regarding the costs incurred by us in our oil and gas activities during the periods indicated.

	Capital and Exploration Expenditures		
	For the Years Ended December 31,		
	2001	2000	1999
	(In thousands)		
Development	$ 98,617	$ 48,996	$ 22,166
Exploration	24,506	17,012	20,809
Acquisitions:			
Proved	41,188	53,482	33,080

Unproved	18,552	5,694	15,129
Total	$182,863	$125,184	$ 91,184

We continuously evaluate opportunities in the marketplace for oil and gas properties and, accordingly, may be a buyer or a seller of properties at various times. We will continue to emphasize smaller niche acquisitions utilizing our technical expertise, financial flexibility and structuring experience. In addition, we are also actively seeking larger acquisitions of assets or companies that would afford opportunities to expand our existing core areas, to acquire additional geoscientists or to gain a significant acreage and production foothold in a new basin.

St. Mary's total costs incurred for capital and exploration activities in 2001 increased $57.7 million or 46% compared to 2000. We spent $141.7 million in 2001 for unproved property acquisitions and domestic exploration and development compared to $71.7 million for the comparable period in 2000. Unproved property acquisitions increased by $12.9 million as a result of general leasing activity and our acquisition of coalbed methane development leases in the Hanging Woman Basin of Montana and Wyoming. We have drilled an 18-well pilot program and are evaluating its results. We are also currently investigating permitting and environmental issues related to the development. We will be unable to determine the future potential of this development until we have completed the evaluation of our pilot program and have resolved all permitting and environmental issues related to the development. An environmental public interest group has filed a lawsuit against the federal Bureau of Land Management seeking to cancel certain federal leases related to coalbed methane development in Montana, which could affect 46,000 of our 115,000 leased acres. We will monitor this lawsuit as part of our investigation of environmental issues related to these prospects.

In November 2001 we purchased oil and gas properties from Choctaw II Oil & Gas, Ltd. for $40.5 million in cash. We used a portion of our credit facility for this acquisition. The properties are primarily located in the Williston Basin of Montana and North Dakota and in the Green River Basin of Wyoming. The net interests we acquired were producing an estimated 1,200 Bbls of oil and 4,600 Mcf of gas per day when the acquisition was completed.

Capital Expenditure Budget. The 2002 capital expenditure budget is $164 million, of which $60 million is allocated for acquisitions. Budgeted ongoing exploration and development expenditures in 2002 for each of our core areas is as follows (in millions):

o Mid-Continent region	$ 33.0
o Gulf Coast and Gulf of Mexico region	$ 18.0
o ArkLaTex region	$ 14.0
o Williston Basin	$ 22.0
o Permian Basin	$ 9.0
o Other	$ 8.0
Total	$104.0

We believe that the amount not funded from our internally generated cash flow in 2002 can be funded from our existing cash, the net proceeds from the sale of the Notes and our bank credit facility. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors including the number and size of available acquisition opportunities and our ability to assimilate these acquisitions. Also, the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing capability and the success of our development and exploratory activity could lead to funding requirements for further development. If additional development or attractive acquisition opportunities arise, we may consider other forms of financing, including the public offering or private placement of equity or debt securities.

Natural Gas and Oil Hedging. We seek to protect our rate of return on acquisitions of producing properties by hedging cash flow when the economic criteria from our evaluation and pricing model indicate it would be appropriate. Management's strategy is to hedge cash flows from investments currently requiring a gas price in excess of $2.75 per Mcf and an oil price in excess of $22.00 per Bbl in order to meet minimum rate-of-return criteria. Management reviews these hedging parameters on a quarterly basis. We anticipate this strategy will result in the hedging of future cash flows from acquisitions. We generally limit our aggregate hedge position to no more than 35% of total production but will hedge up to 50% of total production in certain circumstances. We seek to minimize basis risk and index the majority of oil hedges to NYMEX prices and the majority of gas hedges to various regional index prices associated with pipelines in proximity to our areas of gas production. Including hedges entered into since December 31, 2001 we have the following swaps in place:

Product	Average Volumes/month	Quantity Type	Average Fixed price	Duration
Natural Gas	1,467,000	MMBtu	$ 2.84	01/02 - 12/02
Natural Gas	168,000	MMBtu	$ 3.01	01/03 - 12/03
Natural Gas	59,000	MMBtu	$ 3.04	01/04 - 12/04
Oil	88,400	Bbls	$ 24.69	01/02 - 12/02
Oil	49,800	Bbls	$ 22.67	01/03 - 12/03

The above schedule excludes commodity positions with Enron North America Corp, which filed for bankruptcy protection in December 2001. Our unrealized discounted hedge gain due from Enron had grown to $4.5 million at the end of November 2001. Accounting rules require us to record the ineffective portion of our hedges in operations. We believe the Enron contracts we owned became ineffective, due to a change in counterparty risk as of November 13, 2001. Accordingly, we adjusted the fair value downward to the reduced estimated

fair value as of that date. A net non-cash loss of $1.6 million was recorded in the fourth quarter of 2001. The portion of the hedge that had been deferred in accumulated other comprehensive income immediately prior to the loss of effectiveness will be recognized as non-cash revenue over the next two years based on the originally scheduled settlement dates. We have estimated that 80% of the revenue will be realized in 2002 and 20% will be realized in 2003. We took all legal steps to preserve our rights under these contracts and sold our claim at a discounted price in February 2002. Both parties have agreed that any events resulting in an adjustment in the amount of the claim, as contrasted with the amount collected, will cause a proportional reimbursement from one party to the other.

Since the Enron bankruptcy filing, we have further diversified our hedge positions with various counterparties and require that such counterparties have clear indications of current financial strength.

KMOC Stock. In January 2002 we sold our remaining KMOC common stock resulting in a gain of $838,000.

Accounting Matters

On January 1, 2001 we adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities." The adoption of SFAS No. 133 resulted in St. Mary recording a liability of $45.7 million for the fair value of the derivative instruments at January 1, 2001. The adoption entry resulted in deferral of the recognition of this liability to accumulated other comprehensive loss of $28.6 million at January 1, 2001. For 2001 we recognized a $1.6 million net hedge loss from hedge ineffectiveness on derivative instruments that were designated and qualified as cash flow hedging instruments comprised primarily of the loss of effectiveness on Enron North America Corp. hedge contracts. We anticipate that all hedge transactions will occur as expected.

In June 2001 the Financial Accounting Standards Board issued SFAS No. 141, "Business Combinations." Under this statement all business combinations must be accounted for under the purchase method. The pooling method is no longer allowed. The statement also establishes criteria to assess when to recognize intangible assets separately from goodwill. SFAS No. 141 is effective for business combinations initiated after June 30, 2001 and for all business combinations using the purchase method for which the date of acquisition is after June 30, 2001. At this time we have no pending business combinations that would be affected by the adoption of this statement.

In June 2001 the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This statement addresses the accounting for goodwill and other intangible assets and provides specific guidance for testing goodwill and other intangible assets for impairment. This statement is effective for fiscal years beginning after December 15, 2001. The adoption of this statement did not have a material effect on our financial position or results of operations.

In July 2001 the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." This statement requires companies to recognize the fair value of an asset retirement liability in the financial statements by capitalizing that cost as part of the cost of the related long-lived asset. The asset retirement liability should then be allocated to expense by using a systematic and rational method. The statement is effective January 1, 2003. We have not determined the impact of adoption of this statement.

In August 2001 the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement provides a single accounting model for long-lived assets to be disposed of and changes the criteria that would have to be met to classify an asset as held-for-sale. The statement also requires expected future operating losses from discontinued operations to be recognized in the periods in which the losses are incurred, which is a change from the current requirement of recognizing such operating losses as of the measurement date. The statement is effective January 1, 2002. The adoption of the statement did not have a material effect on our financial position or results of operations.

Effects of Inflation and Changing Prices

Within the United States in 2000 and 2001 general cost inflation had an effect on St. Mary as reflected in increased drilling costs and lease operating costs. We cannot predict the future extent of any such effect.

St. Mary's results of operations and cash flows are affected by material changes in oil and gas prices. Oil and gas prices are strongly impacted by North American influences on gas and global influences on oil in relation to supply and demand for petroleum products. Oil and gas prices are further impacted by the quality of the oil and gas to be sold and the location of our producing properties in relation to markets for our products. Oil and gas price increases or decreases have a corresponding effect on our revenues from oil and gas sales. Oil and gas prices also affect the prices charged for drilling and related services. As oil and gas prices increase, revenues increase and there is usually a corresponding increase in our costs of drilling and related services. Also, as oil and gas prices increase, the cost of acquiring producing properties increases, which could limit the number and accessibility of quality properties on the market.

Material changes in oil and gas prices affect the current and future value of our estimated proved reserves and our borrowing capability, which is largely based on the value of such proved reserves. Declining natural gas prices and volatile oil prices characterized most of 2001. The supply of drilling rigs, personnel, supplies and services was tight through the first half of the year and the cost of each of these items continued to increase as the service sector ran at capacity. At the end of the year, record gas in storage, excess OPEC capacity and a weakened economy resulted in a decrease in demand for these services. In the near-term we expect decreased competition for these limited resources to result in stabilization or decreases in the cost of both materials and personnel and corresponding effects on the cost to explore for, drill for and produce oil and gas. We continue to have good relationships with our vendors due to our reputation for timely payment of invoices, a positive by-product of our strong balance sheet.

Environmental

St. Mary's compliance with applicable environmental regulations has not resulted in any significant capital expenditures or materially adverse effects to our liquidity or results of operations. We believe we are in substantial compliance with environmental regulations and foresee that no material expenditures will be incurred in the future. However, we are unable to predict the impact that future compliance with regulations may have on future capital expenditures, liquidity and results of operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

St. Mary holds derivative contracts and financial instruments that have cash flow and net income exposure to changes in commodity prices or interest rates. Financial and commodity-based derivative contracts are used to limit the risks inherent in some crude oil and natural gas price changes that have an effect on us. In prior years we have occasionally hedged interest rates, and may do so in the future should circumstances warrant.

Our board of directors has adopted a policy regarding the use of derivative instruments. This policy requires every derivative used by St. Mary to relate to underlying offsetting positions, anticipated transactions or firm commitments. It prohibits the use of speculative, highly complex or leveraged derivatives. Under the policy, the Chief Executive Officer and Vice President of Finance must review and approve all risk management programs that use derivatives. The audit committee of our board of directors also periodically reviews these programs.

Commodity Price Risk. St. Mary uses various hedging arrangements to manage its exposure to price risk from natural gas and crude oil production. These hedging arrangements have the effect of locking in for specified periods, at predetermined prices or ranges of prices, the prices we will receive for the volumes to which the hedge relates. Consequently, while these hedging arrangements are structured to reduce our exposure to decreases in prices associated with the hedged commodity, they also limit the benefit we might otherwise receive from any price increases associated with the hedged commodity. The derivative gain or loss effectively offsets the loss or gain on the underlying commodity exposures that have been hedged. The fair value of the swaps are estimated based on quoted market prices of comparable contracts and approximate the net gains or losses that would have been realized if the contracts had been closed out at year-end. The fair values of the futures are based on quoted market prices obtained from the New York Mercantile Exchange and have been adjusted for our hedging of the basis differential accorded to the pipelines relative to our areas of production.

A hypothetical $.10 change in our year-end market prices for natural gas swaps and futures contracts on a notional amount of 20.3 million MMBtu would have caused a potential $1.6 million change in net income (loss) before income taxes for contracts in place on December 31, 2001. A hypothetical $1.00 change in the year-end market prices for crude oil swaps and future contracts on a notional amount of 1.7 MMBbls would have caused a potential $1.5 million change in net income (loss) before income taxes for oil contracts in place on December 31, 2001. These hypothetical changes were discounted to present value using a 7.5% discount rate since the latest expected maturity date of some of the swaps and futures contracts is greater than one year from the reporting date.

Interest Rate Risk. Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one-percentage point parallel shift in the yield curve. The sensitivity analysis presents the hypothetical change in fair value of those financial instruments we held at December 31, 2001 that are sensitive to changes in interest rates. For fixed-rate debt, interest rate changes affect the fair market value but do not impact results of operations or cash flows. Conversely for floating rate debt, interest rate changes generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating rate debt approximates its fair value. At December 31, 2001, we had floating rate debt of $64.0 million and had no fixed rate debt. Assuming constant debt levels, the cash flow impact for the next year resulting from a one-percentage point change in interest rates would be approximately $640,000 before taxes. The results of operations impact may be less than this amount as a direct effect of the capitalization of interest to wells drilled in the next year. In prior years when the debt amount was at a reduced level we capitalized a large portion of our interest expense. Since we cannot predict the exact amount that would be capitalized, we cannot predict the exact effect that a one-percentage point shift would have on the results of operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Consolidated Financial Statements that constitute Item 8 follow the text of this report. An index to the Consolidated Financial Statements and Schedules appears in Item 14(a) of this report.

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this Item concerning St. Mary's directors is incorporated by reference to the information provided in St. Mary's definitive proxy statement for the 2002 annual meeting of shareholders to be filed within 120 days from December 31, 2001. The information required by this Item concerning St. Mary's executive officers is included in Part I--Item 4A--Executive Officers of the Registrant.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided in St. Mary's definitive proxy statement for the 2002 annual meeting of shareholders to be filed within 120 days from December 31, 2001.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this Item is incorporated by reference to the information provided in St. Mary's definitive proxy statement for the 2002 annual meeting of shareholders to be filed within 120 days from December 31, 2001.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this Item is incorporated by reference to the information provided in St. Mary's definitive proxy statement for the 2002 annual meeting of shareholders to be filed within 120 days from December 31, 2001.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules:

All other schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statements and Notes thereto.

(b) Reports on Form 8-K. One report on Form 8-K dated December 10, 2001 was filed during the last quarter of 2001. This report on Form 8-K included Item 2 and Item 7 regarding the acquisition of oil and gas properties from Choctaw II Oil & Gas, LTD.

(c) Exhibits. The following exhibits are filed with or incorporated by reference into this report on Form 10-K:

Exhibit Number	Description
2.1	Agreement and Plan of Merger dated July 27, 1999 among St. Mary Land & Exploration Company, St. Mary Acquisition Corporation, King Ranch, Inc. and King Ranch Energy, Inc. as amended by Amendment No. 1 and Amendment No. 2 to Agreement

and Plan of Merger dated November 8, 1999 (included as Annex A to the joint proxy/consent statement and prospectus contained in the registrant's Amendment No. 2 to Form S-4/A (Registration No. 333-85537) filed on November 12, 1999 and incorporated herein by reference)

2.2	Stock Exchange Agreement dated June 1, 1999 among St. Mary Land & Exploration Company, Robert L. Nance, Penni W. Nance, Amy Nance Cebull and Robert Scott Nance (filed as Exhibit 10.27 to the registrant's Registration Statement on Form S-4 (Registration No. 333-85537) filed on August 19, 1999 and incorporated herein by reference)
2.3	Stock Exchange Agreement dated June 1, 1999 among St. Mary Land & Exploration Company, Robert L. Nance and Robert T. Hanley (filed as Exhibit 10.28 to the registrant's Registration Statement on Form S-4 (Registration No. 333-85537) filed on August 19, 1999 and incorporated herein by reference)
2.4	Stock Exchange Agreement dated June 1, 1999 between St. Mary Land & Exploration Company and Robert T. Hanley (filed as Exhibit 10.29 to the registrant's Registration Statement on Form S-4 (Registration No. 333-85537) filed on August 19, 1999 and incorporated herein by reference)
3.1	Restated Certificate of Incorporation of St. Mary Land & Exploration Company as amended in May 2001 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001 and incorporated herein by reference)
3.2	Restated By-Laws of St. Mary Land & Exploration Company as amended in July 2001 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q (File No. 0-20872) for the quarter ended September 30, 2001 and incorporated herein by reference)

Exhibit Number	Description
4.1	St. Mary Land & Exploration Company Shareholder Rights Plan adopted on July 15, 1999 (filed as Exhibit 4.1 to the registrant's Quarterly Report on Form 10-Q/A (File No. 0-20872) for the quarter ended June 30, 1999 and incorporated herein by reference)
4.2**	First Amendment to Shareholder Rights Plan dated March 15, 2002, as adopted by the Board of Directors on July 19, 2001.
10.1	Stock Option Plan (filed as Exhibit 10.3 to the registrant's Registration Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference)
10.2	Stock Appreciation Rights Plan (filed as Exhibit 10.4 to the registrant's Registration Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference)
10.3	Cash Bonus Plan (filed as Exhibit 10.5 to the registrant's Registration Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference)
10.4	Net Profits Interest Bonus Plan, As Amended on September 19, 1996 and July 24, 1997 and January 28, 1999 filed as Exhibit 10.3 to registrant's Quarterly Report on Form 10-Q (File No. 0-20872) for the quarter ended March 31, 1999 and incorporated herein by reference)
10.5	Summary Plan Description/Pension Plan dated December 30, 1994 (filed as Exhibit 10.35 to the registrant's Annual Report on Form 10-K (File No. 0-20872) for the year ended December 31, 1994 and incorporated herein by reference)
10.6	Non-qualified Unfunded Supplemental Retirement Plan, as amended (filed as Exhibit 10.8 to the registrant's Registration Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference)
10.7	Summary Plan Description 401(k) Profit Sharing Plan (filed as Exhibit 10.34 to the registrant's Annual Report on Form 10-K (File No. 0-20872) for the year ended December 31, 1994 and incorporated herein by reference)
10.8	St. Mary Land & Exploration Company Stock Option Plan, As Amended on March 25, 1999 (filed as Exhibit 10.2 to registrant's Quarterly Report on Form 10-Q (File No. 0-20872) for the quarter ended March 31, 1999 and incorporated herein by reference)
10.9	St. Mary Land & Exploration Company Incentive Stock Option Plan, As Amended on March 25, 1999 (filed as Exhibit 10.1 to registrant's Quarterly Report on Form 10-Q (File No. 0-20872) for the quarter ended March 31, 1999 and incorporated herein by reference)
10.10	St. Mary Land & Exploration Company Employee Stock Purchase Plan (filed as Exhibit 10.48 filed to the registrant's Annual Report on Form 10-K (File No. 0-20872) for the year ended December 31, 1997 and incorporated herein by reference)
10.11	First Amendment to St. Mary Land & Exploration Company Employee Stock Purchase Plan dated February 27, 2001 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q (file No. 0-20872) for the quarter ended June 30, 2001 and incorporated herein by reference)
10.12	Form of Change of Control Severance Agreements (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q (File No. 0-20872) for the quarter ended September 30, 2001 and incorporated herein by reference)
10.13	Employment Agreement between Registrant and Mark A. Hellerstein (filed as Exhibit 10.13 to the registrant's Registration

Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference)

Exhibit Number	Description
10.14	Credit Agreement dated June 30, 1998 (filed as Exhibit 10.52 to the registrant's Quarterly Report on Form 10-Q (File No. 0-20872) for the quarter ended June 30, 1998 and incorporated herein by reference)
10.15	Second Amendment to Credit Agreement dated June 27, 2000 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q (File No. 0-20872) for the quarter ended June 30, 2000 and incorporated herein by reference)
10.16	Third Amendment to Credit Agreement dated April 30, 2001 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q (File No. 0-20872) for the quarter ended June 30, 2001 and incorporated herein by reference)
10.17	Loan and Stock Purchase Agreement dated June 25, 1999 among Resource Capital Fund L.P., St. Mary Land & Exploration Company and St. Mary Minerals Inc. (filed as Exhibit 10.30 to the registrant's Registration Statement on Form S-4 (Registration No. 333-85537) filed on August 19, 1999 and incorporated herein by reference)
10.18	Credit Agreement dated June 25, 1999 among Summo Minerals Corporation, Summo USA Corporation, Resource Capital Fund L.P. and St. Mary Minerals Inc. (filed as Exhibit 10.31 to the registrant's Registration Statement on Form S-4 (Registration No. 333-85537) filed on August 19, 1999 and incorporated herein by reference)
10.19	Replacement Promissory Note dated June 25, 1999 payable to St. Mary Minerals Inc. in the amount of $1,400,000 (filed as Exhibit 10.32 to the registrant's Registration Statement on Form S-4 (Registration No. 333-85537) filed on August 19, 1999 and incorporated herein by reference)
10.20	Pledge and Security Agreement dated June 25, 1999 among Summo Minerals Corporation, Resource Capital Fund L.P., and St. Mary Minerals Inc. (filed as Exhibit 10.33 to the registrant's Registration Statement on Form S-4 (Registration No. 333-85537) filed on August 19, 1999 and incorporated herein by reference)
10.21	Pledge and Security Agreement dated June 25, 1999 among Summo USA Corporation, Resource Capital Fund L.P., and St. Mary Minerals Inc. (filed as Exhibit 10.34 to the registrant's Registration Statement on Form S-4 (Registration No. 333-85537) filed on August 19, 1999 and incorporated herein by reference)
10.22	Warrant Agreement dated June 25, 1999 among Summo Minerals Corporation, Resource Capital Fund L.P. and St. Mary Minerals Inc. (filed as Exhibit 10.35 to the registrant's Registration Statement on Form S-4 (Registration No. 333-85537) filed on August 19, 1999 and incorporated herein by reference)
10.23	Agreement of Sale and Purchase dated October 16, 2000, effective as of September 1, 2000, between JN Exploration and Production Limited Partnership, Colt Resources Corporation, Princeps Partners, Inc., and The William G. Helis Company, LLC (collectively, "JN et al") and St. Mary Land & Exploration Company (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K (File No. 0-20872) dated January 5, 2001 and incorporated herein by reference)
10.24	Purchase and Sale Agreement dated September 28, 2001, effective as of September 1, 2001; between Choctaw II Oil & Gas, LTD and Nance Petroleum Corporation (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K (File No. 0-20872) dated December 10, 2001 and incorporated herein by reference)

Exhibit Number	Description
10.25**	Registration Rights Agreement between St. Mary Land & Exploration Company and Bear, Stearns & Co. Inc., et al dated March 13, 2002
10.26**	St. Mary Land & Exploration Company 5.75% Senior Convertible Notes Due 2022 Indenture dated March 13, 2002
10.27**	First Amendment to Credit Agreement dated December 22, 1998
10.28**	Fourth Amendment to Credit Agreement dated March 4, 2002
21.1**	Subsidiaries of Registrant
23.1*	Consent of Arthur Andersen LLP
23.2*	Consent of Ryder Scott Company, L.P.
24.1**	Power of Attorney

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* Filed with this Form 10-K/A.

** Previously filed.

(d) Financial Statement Schedules. See Item 14(c) above.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors and Stockholders of
St. Mary Land & Exploration Company and Subsidiaries:

We have audited the accompanying consolidated balance sheets of St. Mary Land & Exploration Company (a Delaware corporation) and Subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of St. Mary Land & Exploration Company and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Notes 1 and 10 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities on January 1, 2001.

/s/ ARTHUR ANDERSEN LLP

Denver, Colorado,
February 18, 2002.

ITEM 8. FINANCIAL STATEMENTS AND SUPLEMENTARY DATA

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except share amounts)

ASSETS	December 31, 2001	December 31, 2000
Current assets:		
Cash and cash equivalents	$ 4,116	$ 6,619
Accounts receivable	46,484	55,068
Prepaid expenses and other	2,337	2,134
Accrued derivative asset	8,194	-
Refundable income taxes	11,090	-
Deferred income taxes	-	163
Total current assets	72,221	63,984
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	518,912	385,076
Less accumulated depletion, depreciation and amortization	(216,288)	(171,412)
Unproved oil and gas properties, net of impairment allowance of $8,908 in 2001 and $7,956 in 2000	53,054	35,497
Other property and equipment, net of accumulated depreciation of $3,120 in 2001 and $3,600 in 2000	3,252	3,250
	358,930	252,411
Other assets:		
Khanty Mansiysk Oil Corporation stock	1,651	1,651
Other assets	4,187	3,849
	5,838	5,500
	$ 436,989	$ 321,895

LIABILITIES AND STOCKHOLDERS' EQUITY

	2001	2000
Current liabilities:		
Accounts payable and accrued expenses	$ 34,858	$ 23,345
Deferred tax liability	3,363	-

Total current liabilities	38,221	23,345
Long-term liabilities:		
Long-term debt	64,000	22,000
Deferred income taxes	47,685	24,820
Other noncurrent liabilities	255	987
	111,940	47,807
Commitments and contingencies (Notes 1,6,7,8,10)		
Minority interest	711	607
Stockholders' equity:		
Common stock, $0.01 par value: authorized - 100,000,000 shares; issued and outstanding - 28,779,808 shares in 2001 and 28,553,826 shares in 2000	288	286
Additional paid-in capital	137,384	132,973
Treasury stock - at cost: 1,009,900 shares in 2001 and 395,600 shares in 2000	(16,210)	(3,339)
Retained earnings	157,739	120,075
Accumulated other comprehensive income	6,916	141
Total stockholders' equity	286,117	250,136
	$ 436,989	$ 321,895

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the Years Ended December 31,		
	2001	2000	1999
Operating revenues:			
Oil and gas production	$ 203,973	$ 188,407	$73,387
Gain (loss) on sale of proved properties	367	3,404	(55)
Other oil and gas revenue	2,166	1,421	1,166
Gain on sale of KMOC stock	-	2,156	-
Other revenues	963	278	416
Total operating revenues	207,469	195,666	74,914
Operating expenses:			
Oil and gas production	55,000	38,461	19,574
Depletion, depreciation and amortization	51,346	40,129	22,574
Exploration	19,518	9,633	11,593
Impairment of proved properties	820	4,449	3,982
Abandonment and impairment of unproved properties	3,865	1,841	6,616
General and administrative	11,762	11,166	9,172
Unrealized derivative loss	1,573	-	-
Other	1,673	1,437	1,802
Total operating expenses	145,557	107,116	75,313
Income (loss) from operations	61,912	88,550	(399)
Nonoperating income (expense):			
Interest income	466	897	1,008
Interest expense	(90)	(160)	(933)
Income (loss) before income taxes	62,288	89,287	(324)
Income tax expense (benefit)	21,829	33,667	(406)
Net income	$ 40,459	$ 55,620	$ 82
Basic net income per common share	$ 1.45	$ 2.00	$ -
Diluted net income per common share	$ 1.42	$ 1.97	$ -
Basic weighted average shares outstanding	27,973	27,781	22,198

	2001	2000	1999
Diluted weighted average shares outstanding	28,555	28,271	22,329

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(In thousands, except share amounts)

	Common Stock		Additional Paid-in	Retained	Treasury Stock		Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Earnings	Shares	Amount	Income	Equity
Balance, December 31, 1998	21,984,894	$ 220	$ 67,651	$ 69,341	(295,600)	$ (2,470)	$ -	$ 134,742
Comprehensive income:								
Net Income	-	-	-	82	-	-	-	82
Unrealized net gain on marketable equity securities available for sale	-	-	-	-	-	-	284	284
Total comprehensive income								366
Cash dividends, $ 0.10 per share	-	-	-	(2,193)	-	-	-	(2,193)
Treasury stock purchases	-	-	-	-	(70,000)	(525)	-	(525)
Issuance for Employee Stock Purchase Plan	32,794	-	258	-	-	-	-	258
Employee Stock Purchase Plan disqualified distributions	-	-	20	-	-	-	-	20
Sale of common stock, including income tax benefit of stock option exercises	17,660	-	123	-	-	-	-	123
Directors' stock compensation	7,200	-	57	-	-	-	-	57
Issuance for Acquisition of Nance Petroleum Corporation	518,988	6	3,086	-	-	-	-	3,092
Issuance for Acquisition of King Ranch Energy, Inc.	5,332,374	53	52,779	-	-	-	-	52,832
Balances, December 31, 1999	27,893,910	$ 279	$ 123,974	$ 67,230	(365,600)	$ (2,995)	$ 284	$ 188,772
Comprehensive income:								
Net Income	-	-	-	55,620	-	-	-	55,620
Unrealized net loss on marketable equity securities available for sale	-	-	-	-	-	-	(143)	(143)
Total comprehensive income								55,477
Cash dividends, $ 0.10 per share	-	-	-	(2,775)	-	-	-	(2,775)
Treasury stock purchases	-	-	-	-	30,000)	(344)	-	(344)
Issuance for Employee Stock Purchase Plan	32,296	-	311	-	-	-	-	311
Employee Stock Purchase Plan disqualified distributions	-	-	3	-	-	-	-	3
Sale of common stock, including income tax benefit of stock option exercise	619,220	6	8,597	-	-	-	-	8,603
Directors' stock compensation	8,400	1	88	-	-	-	-	89
Balances, December 31, 2000	28,553,826	$ 286	$ 132,973	$ 120,075	(395,600)	$ (3,339)	$ 141	$ 250,136
Comprehensive income:								
Net Income	-	-	-	40,459	-	-	-	40,459
Unrealized net loss on marketable equity securities available for sale	-	-	-	-	-	-	(132)	(132)
Cumulative effect of adoption of accounting principle	-	-	-	-	-	-	(28,587)	(28,587)
Change in derivative instrument fair value	-	-	-	-	-	-	35,494	35,494
Total comprehensive income								47,234
Cash dividends, $ 0.10 per share	-	-	-	(2,795)	-	-	-	(2,795)
Treasury stock purchases	-	-	-	-	(614,300)	(12,871)	-	(12,871)
Issuance for Employee Stock Purchase Plan	29,772	-	575	-	-	-	-	575
Sale of common stock, including income tax benefit of stock option exercise	187,810	2	3,598	-	-	-	-	3,600
Directors' stock compensation	8,400	-	238	-	-	-	-	238
Balances, December 31, 2001	28,779,808	$ 288	$ 137,384	$ 157,739	(1,009,900)	$ (16,210)	$ 6,916	$ 286,117

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Years Ended December 31,		
	2001	2000	1999
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 40,459	$ 55,620	$ 82
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale of KMOC stock	-	(2,156)	-
(Gain) loss on sale of proved properties	(367)	(3,404)	55
Unrealized derivative loss	1,573	-	-
Depletion, depreciation and amortization	51,346	40,129	22,574
Impairment of proved properties	820	4,449	3,982
Exploratory dry hole expense	9,028	789	4,759
Abandonment and impairment of unproved properties	3,865	1,841	6,616
Deferred income taxes	23,726	21,348	(898)
Minority interest and other	(1,327)	1,260	29
	129,123	119,876	37,199
Changes in current assets and liabilities:			
Accounts receivable	(629)	(23,138)	4,983
Prepaid expenses and other	(11,754)	254	1,118
Accounts payable and accrued expenses	10,752	(4,652)	(2,580)
Other	-	(73)	35
Net cash provided by operating activities	127,492	92,267	40,755
Cash flows from investing activities:			
Proceeds from sale of oil and gas properties	4,771	3,573	1,056
Capital expenditures	(131,680)	(65,241)	(34,994)
Acquisition of oil and gas properties	(39,124)	(52,076)	(5,294)
Proceeds from distribution of KMOC stock	6,960	-	-
Sale of Chelsea Corporation	-	-	2,066
Receipts from restricted cash	-	-	720
Investment in St. Mary Energy Company	-	(420)	12,068
Other	(2)	1,296	2,135
Net cash used in investing activities	(159,075)	(112,868)	(22,243)
Cash flows from financing activities:			
Proceeds from long-term debt	147,050	45,050	29,750
Repayment of long-term debt	(105,050)	(36,050)	(39,537)
Proceeds from sale of common stock	2,746	7,143	311
Repurchase of common stock	(12,871)	(344)	(525)
Dividends paid	(2,795)	(2,775)	(2,193)
Other	-	1	56
Net cash provided by (used in) financing activities	29,080	13,025	(12,138)
Net change in cash and cash equivalents	(2,503)	(7,576)	6,374
Cash and cash equivalents at beginning of period	6,619	14,195	7,821
Cash and cash equivalents at end of period	$ 4,116	$ 6,619	$ 14,195

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

Supplemental schedule of additional cash flow information and noncash activities:

For the Years Ended December 31,		
2001	2000	1999

		(in thousands)	
Cash paid for interest	$ 539	$ 764	$ 916
Cash paid for income taxes	10,355	11,205	92
Cash paid for exploration expenses	19,518	9,032	11,826

In January 2001 the Company issued 8,400 shares of common stock to its directors and recorded compensation expense of $237,852.

In June 2000 the Company received equipment valued at $1,202,000 as partial proceeds for property sold.

In January 2000 the Company issued 8,400 shares of common stock to its directors and recorded compensation expense of $88,368.

In December 1999 the Company acquired St. Mary Energy Company (formerly known as King Ranch Energy, Inc.) for 5,332,374 shares of the Company's common stock valued at $52,832,000. The acquisition was accounted for as a purchase.

Following is a table of the noncash items acquired in the 1999 purchases of Nance Petroleum Corporation and King Ranch Energy, Inc. (in thousands):

	Nance Petroleum	King Ranch Energy
Accounts receivable & other assets	$ 789	$ 9,772
Property & equipment	6,365	25,056
Accounts payable	(642)	(4,490)
Deferred income taxes	(667)	10,426
Long-term debt	(3,389)	-

In June 1999 the Company acquired Nance Petroleum Corporation and Quanterra Alpha Limited Partnership for 518,988 shares of the Company's common stock valued at $3,091,000 together with the assumption of $3,389,000 of Nance Petroleum Corporation debt. The acquisition was accounted for as a purchase.

In January 1999 the Company issued 7,200 shares of common stock to its directors and recorded compensation expense of $54,612.

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001

1. Summary of Significant Accounting Policies:

Description of Operations:

St. Mary Land & Exploration Company ("St. Mary" or the "Company") is an independent energy company engaged in the exploration, development, acquisition and production of natural gas and crude oil. The Company's operations are conducted entirely in the United States.

Basis of Presentation:

In July 2000, St. Mary's Board of Directors approved a two-for-one stock split effected in the form of a stock dividend whereby one additional common share of stock was distributed for each common share outstanding. The stock split was distributed on September 5, 2000 to shareholders of record as of the close of business on August 21, 2000. All share and per share amounts for all periods presented herein have been restated to reflect this stock split.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Subsidiaries that are not wholly-owned are accounted for using full consolidation with minority interest or by the equity or cost method as appropriate. All significant intercompany accounts and transactions have been eliminated.

The Company accounts for its investment in Summo Minerals Corporation ("Summo") under the cost method of accounting. The accounting for this investment was changed from the equity method to the cost method in June 1999 after a transfer of common shares that reduced the Company's ownership percentage below 20%. The Company's interests in other oil and gas ventures and partnerships are accounted for using full consolidation with minority interest, including its 58% investment in Box Church Gas Gathering, LLC. The Company's 90% interest in Roswell, LLC was accounted for using full consolidation with minority interest until December 2000 when the remaining 10% interest was purchased. The Company's 74% investment in Panterra Petroleum ("Panterra") was proportionately consolidated until June 1999 when the remaining 26% was acquired through the purchase of Nance Petroleum Corporation ("Nance").

Cash and Cash Equivalents:

The Company considers all highly liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value because the instruments have maturity dates of three months or less.

Concentration of Credit Risk:

Substantially all of the Company's receivables are within the oil and gas industry, primarily from purchasers of oil and gas and from joint interest owners. Although diversified within many companies, collectability is dependent upon the general economic conditions of the industry. The receivables are not collateralized, and to date the Company has had minimal bad debts.

The Company has accounts with separate banks in Denver, Colorado; Shreveport, Louisiana; Tulsa, Oklahoma; Lafayette, Louisiana; and Billings,

Montana. At December 31, 2001 and 2000, the Company had $6,576,000 and $11,093,000 respectively, invested in money market funds, including margin accounts consisting of corporate commercial paper, repurchase agreements and U.S. Treasury obligations. The Company's policy is to invest in highly rated instruments and to limit the amount of credit exposure at each individual institution.

Oil and Gas Producing Activities:

The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. Exploratory dry hole costs are included in cash flows from investing activities within the consolidated statements of cash flows. The costs of development wells are capitalized whether productive or nonproductive.

Geological and geophysical costs on exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred. An impairment allowance is provided on a property-by-property basis when the Company determines that the unproved property will not be developed. Depletion, depreciation and amortization ("DD&A") of capitalized costs of proved oil and gas properties is provided on a field-by-field basis using the units of production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement and abandonment costs and the anticipated proceeds from equipment salvage. The restoration, dismantlement and abandonment costs for onshore properties are expected to be offset by the residual value of lease and well equipment. The Company had a recorded offshore abandonment liability of $9,500,000 as of December 31, 2001 based on total expected abandonment costs of $10,251,000 and a liability of $9,500,000 as of December 31, 2000 based on total expected abandonment costs of $10,611,000. This liability is included in accumulated DD&A on the consolidated balance sheets. The Company recorded $313,000, $1,988,000 and $34,000 of offshore abandonment liability accretion as part of DD&A expense in the consolidated statements of operations for the years ended December 31, 2001, 2000 and 1999, respectively.

The Company reviews its long-lived assets for impairments when events or changes in circumstances indicate that an impairment may have occurred. The impairment test compares the expected undiscounted future net revenues on a field-by-field basis with the related net capitalized costs at the end of each period. Expected future cash flows are calculated on all proved reserves using a 15% discount rate and escalated prices. When the net capitalized costs exceed the undiscounted future net revenue of a property, the cost of the property is written down to fair value, which is determined using discounted future net revenues. During 2001, 2000 and 1999 the Company recorded impairment charges for proved properties of $820,000, $4,449,000 and $3,982,000, respectively.

Sales of Producing and Nonproducing Properties:

The sale of a partial interest in a proved property is accounted for as normal retirement, and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties and is included in the results of operations.

The sale of a partial interest in an unproved property is accounted for as a recovery of cost when substantial uncertainty exists as to recovery of the cost applicable to the interest retained. A gain on the sale is recognized to the extent that the sales price exceeds the carrying amount of the unproved property.

Other Property and Equipment:

Other property and equipment is recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repairs are expensed when incurred. Depreciation is provided using the straight-line method over the estimated useful lives of the assets from 3 to 15 years. Gains and losses on dispositions of other property and equipment are included in the results of operations.

Gas Balancing:

The Company uses the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold by the Company. The Company records revenue for its share of gas sold by other owners that cannot be volumetrically balanced in the future due to insufficient remaining reserves. Related receivables totaling $984,000 at December 31, 2001 and $1,035,000 at December 31, 2000 are included in other assets in the accompanying balance sheets. The Company also reduces revenue for gas sold by the Company that cannot be volumetrically balanced in the future due to insufficient remaining reserves. Related payables totaling $353,000 at December 31, 2001 and $335,000 at December 31, 2000 are included in other noncurrent liabilities in the accompanying balance sheets. The Company's remaining overproduced and underproduced gas balancing positions are considered in the Company's proved oil and gas reserves (see Note 11).

Financial Instruments:

Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," was adopted on January 1, 2001. SFAS No. 133 requires companies to report all derivatives at fair value as either assets or liabilities and bases the accounting treatment of the derivatives on the reasons an entity holds the instrument. The adoption of SFAS No. 133 resulted in the Company recording a liability of $45,699,000 for the fair value of the derivative instruments at January 31, 2001. The Company's adoption entry also resulted in deferral of the recognition of this liability to accumulated other comprehensive loss of $28,587,000.

The Company seeks to protect its rate of return on acquisitions of producing properties or drilling prospects by hedging cash flow when the economic criteria from its evaluation and pricing model indicate it would be appropriate. The derivative instruments used for this purpose are designated and qualify as cash flow hedging instruments under SFAS No. 133. Management's strategy is to hedge cash flows from investments currently requiring a gas price in excess of $2.75 per Mcf and an oil price in excess of $22.00 per Bbl in order to meet minimum rate-of-return criteria. Management reviews these hedging parameters on a quarterly basis. The Company generally limits its aggregate hedge position to no more than 35% of its total production but will hedge up to 50% of total production in certain circumstances. The Company seeks to minimize basis risk and indexes the majority of its oil hedges to NYMEX prices and the majority of its gas hedges to various regional index prices associated with pipelines in proximity to the Company's areas of gas production.

The Company's hedge positions are diversified with various counterparties, and the Company requires that such counterparties have clear indications of current financial strength. See Note 10 for additional discussion of derivatives.

Income Taxes:

Deferred income taxes are provided on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively.

Earnings Per Share:

Basic net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding during each year. Diluted net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding and other dilutive securities. Dilutive securities of the Company consist entirely of outstanding options to purchase the Company's common stock. The outstanding dilutive securities for the years ended December 31, 2001, 2000 and 1999 were 582,313, 490,288 and 131,356, respectively. Antidilutive options not considered in the diluted net income per share calculation were 625,492, 0 and 513,855 for the years ended December 31, 2001, 2000 and 1999.

Stock-Based Compensation:

The Company accounts for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB No. 25") and related interpretations. Compensation expense for stock options, if any, is measured as the excess of the quoted market price of the Company's stock at the date of grant over the amount an employee must pay to acquire the stock.

SFAS No. 123, "Accounting for Stock-Based Compensation," established accounting and disclosure requirements using a fair-value-based method of accounting for stock-based employee compensation plans. The Company has elected to remain on its current method of accounting as described above, and has adopted the disclosure requirements of SFAS No. 123.

Comprehensive Income:

Comprehensive income consists of net income and unrealized gains and losses on marketable equity securities held for sale and the effective component of derivative instruments (net of tax) classified as cash flow hedges. Comprehensive income is presented in the consolidated statements of stockholders' equity and comprehensive income.

Major Customers:

During 2001 two customers individually accounted for 12.0% and 11.3% of the Company's total oil and gas production revenue. During 2000 one customer individually accounted for 22.3% of the Company's total oil and gas production revenue. During 1999 one customer individually accounted for 13.3% of the Company's total oil and gas production revenue.

Industry Segment and Geographic Information:

The Company operates in one industry segment, which is the exploration, development and production of natural gas and crude oil, and all of the Company's operations are conducted in the United States. Consequently, the Company currently reports as a single industry segment.

Use of Estimates in the Preparation of Financial Statements:

The preparation of financial statements in conformity with accounting principles generally accepted in the United Stated requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, 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. Actual results could differ from those estimates.

Reclassifications:

Certain amounts in the 2000 and 1999 consolidated financial statements have been reclassified to correspond to the 2001 presentation.

Recently Issued Accounting Standards:

In June 2001 the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations." Under this statement all business combinations must be accounted for under the purchase method. The pooling method is no longer allowed. The statement also establishes criteria to assess when to recognize intangible assets separately from goodwill. SFAS No. 141 is effective for business combinations initiated after June 30, 2001 and for all business combinations using the purchase method for which the date of acquisition is after June 30, 2001. At this time we have no pending business combinations that would be affected by the adoption of this statement.

In June 2001 the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This statement addresses the accounting for goodwill and other intangible assets and provides specific guidance for testing goodwill and other intangible assets for impairment. This statement is effective for fiscal years beginning after December 15, 2001. The adoption of this statement did not have a material effect on our financial position or results of operations.

In July 2001 the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." This statement requires companies to recognize the fair value of an asset retirement liability in the financial statements by capitalizing that cost as part of the cost of the related long-lived asset. The asset retirement liability should then be allocated to expense by using a systematic and rational method. The statement is effective January 1, 2003. We have not determined the impact of adoption of this statement.

In August 2001 the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement provides a single accounting model for long-lived assets to be disposed of and changes the criteria that would have to be met to classify an asset as held-for-sale. The statement also requires expected future operating losses from discontinued operations to be recognized in the periods in which the losses are incurred, which is a change from the current requirement of recognizing such operating losses as of the measurement date. The statement is effective January 1, 2002. The adoption of the statement did not have a material effect on our financial position or results of operations.

2. Accounts Receivable:

Accounts receivable are composed of the following:

	December 31, 2001	December 31, 2000
	(In thousands)	
Accrued oil and gas sales	$ 29,041	$ 38,159
Due from joint interest owners	17,042	6,497
Receivable for sale of KMOC stock	-	7,009
Other	401	3,403
Total accounts receivable	$ 46,484	$ 55,068

3. Acquisitions

On November 29, 2001 the Company completed the acquisition of oil and gas properties located in Montana, North Dakota and Wyoming from Choctaw II Oil and Gas, LTD. The Company paid $40,526,000 in cash after normal price adjustments. The Company utilized a portion of its existing credit facility to fund the acquisition, and the transaction was accounted for as a purchase.

On December 28, 2000 the Company completed the acquisition of oil and gas properties primarily located in the Anadarko Basin of Oklahoma from JN Exploration and Production Limited Partnership and affiliates for $31,613,000 in cash after normal purchase price adjustments. The Company utilized cash on hand and a portion of its existing credit facility with Bank of America to fund the acquisition. The transaction was accounted for as a purchase.

On December 17, 1999 the Company completed the purchase of King Ranch Energy, Inc. ("KRE") for 5,332,374 shares of common stock valued at $52,832,000 together with transaction costs of $2,339,000. After the acquisition KRE's name was changed to St. Mary Energy Company. The acquired properties are located primarily in the Gulf of Mexico and the onshore Gulf Coast. The KRE acquisition has been accounted for by the purchase method of accounting and, accordingly, the results of operations of KRE beginning December 17, 1999 are included in the accompanying consolidated financial statements.

On June 1, 1999 the Company completed the purchase of Nance Petroleum Corporation and Quanterra Alpha Limited Partnership for 518,988 shares of the Company's common stock valued at $3,091,000 together with transaction costs of $56,000 and the assumption of $3,189,000 of Nance debt. The acquisition included the 26% of Panterra the Company did not previously own, as well as certain other properties. The properties acquired are located in the Williston Basin of Montana and North Dakota. The acquisition was accounted for as a purchase.

4. Income Taxes:

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2001	2000	1999
		(In thousands)	
Current taxes:			
Federal	$ 1,114	$ 11,194	$ 219
State	620	1,181	315
Deferred taxes	20,095	21,292	(940)
Total income tax expense (benefit)	$ 21,829	$ 33,667	$ (406)

The above taxes are net of alternative fuels credits (Internal Revenue Code Section 29) of $185,000 in 2001, $79,000 in 2000, and $283,000 in 1999. Additionally, current federal tax does not reflect the tax benefit for deductions from stock option exercises of $930,000 in 2001, $1,771,000 in 2000 and $36,000 in 1999. Net federal taxes payable for the years ended December 31, 2001, 2000 and 1999 were $184,000, $9,423,000 and $183,000, respectively, and have been reduced by the tax benefit of stock option exercises.

The components of the net deferred tax liability are as follows:

	December 31,	
	2001	2000
	(In thousands)	
Deferred tax liabilities:		
Oil and gas properties	$ 54,104	$ 32,031
Derivative instruments	3,903	-
Other	147	282
Total deferred tax liabilities	58,154	32,313
Deferred tax assets:		
Other, primarily employee benefits	1,716	5,005
State tax net operating loss carryforward	1,915	1,006
State and federal income tax benefit	3,497	1,817
Alternative minimum tax credit carryforward	184	-
Total deferred tax assets	7,312	7,828
Valuation allowance	(206)	(172)
Net deferred tax assets	7,106	7,656
Total net deferred tax liabilities	51,048	24,657
Current deferred income tax assets (liabilities)	(3,363)	163
Non-current net deferred tax liabilities	$ 47,685	$ 24,820
Current refundable income taxes (current income taxes payable)	$ 11,090	$ (1,162)

In accordance with SFAS No. 109, "Accounting for Income Taxes," the Company records purchase adjustments to its long-term deferred income tax liability accounts to more closely align book and tax basis at the time of acquisition. These adjustments mitigate the effect of deferred income tax expense or reduced deferred income tax benefit on future net income before income tax from acquisitions that utilize the purchase method for accounting principles generally accepted in the United States and are considered to be tax-free basis transfers for tax accounting. During 1999 the Company adjusted its long-term deferred income tax liability account for a $667,000 increase relating to its Nance stock acquisition and recorded a $10,426,000 decrease for

its KRE stock acquisition, as Nance's book basis was greater than its tax basis, and KRE's tax basis was greater than its book basis. During 2000 the Company recorded a $2,972,000 increase in the KRE adjustment to reflect the utilization of additional tax benefits of KRE by King Ranch, Inc on its 1999 federal consolidated income tax return. There were no purchase adjustments to the Company's long-term deferred income tax liability accounts in 2001.

At December 31, 2001, the Company had state net operating loss carryforwards of approximately $40,300,000 that expire between 2002 and 2017. The Company's valuation allowance relates in part to its state net operating loss carryforwards, since the Company anticipates that a portion of the carryovers from prior years will expire before they can be utilized, and in part to a portion of the anticipated state benefit from federal income tax expense incurred as the Company's existing taxable temporary differences reverse. The net change in valuation allowance in 2001 results from the state benefit of federal income tax that is now offset by reversing state temporary differences.

Income tax expense and benefit differs from the amount that would be provided by applying the statutory federal income tax rate to income before income taxes for the following reasons:

	For the Years Ended December 31,		
	2001	2000	1999
	(In thousands)		
Federal statutory taxes	$ 20,420	$ 30,267	$ (137)
Increase (decrease) in taxes resulting from:			
State taxes (net of federal benefit)	2,017	4,342	105
Statutory depletion	(238)	(71)	(110)
Alternative fuels credits (Section 29)	(185)	(79)	(283)
Change in valuation allowance	34	(826)	(17)
Other	(219)	34	36
Income tax expense (benefit) from continuing operations	$ 21,829	$ 33,667	$ (406)

5. Long-term Debt and Notes Payable:

On March 4, 2002 St. Mary entered into an agreement to amend the existing long-term revolving credit agreement. The lender may periodically re-determine the aggregate borrowing base depending upon the value of St. Mary's oil and gas properties and other assets. The accepted borrowing base was $100.0 million at December 31, 2001, and the stated total borrowing base was $170.0 million. The amendment did not change these amounts. The credit agreement has a maturity date of December 31, 2006 and includes a revolving period that matures on June 30, 2003. Quarterly principal payments will begin on September 30, 2003. The amended agreement deletes all reference to and provisions of the short-term tranche previously available to St. Mary. The Company must comply with certain covenants including maintenance of stockholders' equity at a specified level and limitations on additional indebtedness. As of December 31, 2001 and 2000, $64.0 million and $22.0 million, respectively, was outstanding under this credit agreement. These outstanding balances accrue interest at rates determined by St. Mary's debt to total capitalization ratio. During the revolving period of the loan, loan balances accrue interest at the Company's option of either (1) the higher of the federal funds rate plus 1/2% or the prime rate, plus an additional 1/4% when the Company's debt to capitalization ratio is greater than 50%, or (2) the LIBOR rate plus (a) 1% when the Company's debt to toatl capitalization ratio is less than 30%, (b) 1 1/4% when the Company's debt to capitalization ratio is greater than or equal to 30% but less than 40%, (c) 1 3/8% when the Company's debt to capitalization ratio is greater than or equal to 40% but less than 50%, or (d) 1 5/8% when the Company's debt to capitalization ratio is greater than 50%.The debt to total capitalization ratio as defined under the agreement was 22.4% as

of December 31, 2001. The weighted average interest rate paid in 2001 was 5.9% including commitment fees paid on the unused portion of the borrowing base.

The carrying value of long-term debt approximates fair value because the debt is variable rate and reprices in the short term.

The Company's estimated annual principal payments under the credit agreement for the next five years are as follows:

Years Ending December 31,	(In thousands)
2002	$ -
2003	6,400
2004	12,800
2005	12,800

2006	32,000
Total	$ 64,000

6. Commitments and Contingencies:

The Company leases office space under various operating leases with terms extending as far as May 31, 2012. The Company has noncancelable annual subleases with affiliates of approximately $122,016 for the same term as the Company's primary office lease. Rent expense, net of sublease income, was $839,000, $782,000 and $611,000 in 2001, 2000 and 1999, respectively. The Company also leases office equipment under various operating leases. The annual minimum lease payments for the next five years are presented below:

Years Ending December 31,	(In thousands)
2002	$ 931
2003	1,129
2004	866
2005	743
2006	743
Thereafter	3,502
Total	$ 7,914

7. Compensation Plans:

In January 1992 the Company adopted two compensation plans for key employees. A cash bonus plan allows participants to receive up to 100% of their aggregate base salary. Any awards under the cash bonus plans are based on a combination of Company and individual performance. The Company accrued $170,000 for cash bonuses in 2001 that will be paid in 2002, $1,957,000 for cash bonuses in 2000 that were paid in 2001, and $2,293,000 for cash bonuses in 1999 that were paid in 2000. A net profits interest bonus plan allows participants to receive an aggregate 10% net profits interest after the Company has recovered 100% of its investment in various pools of oil and gas wells completed or acquired during a given year. This interest increases to 20% after the Company recovers 200% of its investment. The Company records compensation expense once it recovers its investment and net profits attributable to the properties are payable to the employees. The Company recorded compensation expense of $5,259,000 in 2001, $877,000 in 2000 and $574,000 in 1999 relating to the net profits interest bonus plan.

In March 1992 the Company adopted a stock appreciation rights ("SAR") plan for officers and directors. SARs vest over a four-year period, with payment occurring five years after the date of grant. Between 1993 and 1996 the Company awarded a total of 342,824 share rights with values ranging from $5.75 to $7.00 per share. Compensation expense recognized under the SAR plan was $12,000 in 2000 and $280,000 in 1999. In November 1996 the Company terminated future awards under the Company's SAR plan and capped the value of the share rights under the SAR plan at the then fair market value of the Company's common stock of $10.25 per share. SAR compensation expense recorded after the termination of future awards related to the vesting of SARs outstanding at the time of the termination of future awards and to the fluctuation of the stock price below the capped price. The final SAR payments were made in February 2001. No compensation expense was recognized under the SAR plan in 2001.

The Company has a defined contribution pension plan ("401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 9% of their base salaries. The Company matches each employee's contributions up to 6% of the employee's base salary and also may make additional contributions at its discretion. The Company's contributions to the 401(k) Plan were $559,000, $412,000, and $288,000 for the years ended December 31, 2001, 2000, and 1999, respectively.

In September 1997 the Board of Directors approved the St. Mary Land & Exploration Company Employee Stock Purchase Plan ("Stock Purchase Plan"), which became effective January 1, 1998. Under the Stock Purchase Plan eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15% of eligible compensation. The purchase price of the stock is 85% of the lower of the fair market value of the stock on the first or last day of the purchase period. The Stock Purchase Plan is intended to qualify under Section 423 of the Internal Revenue Code. The Company has set aside 1,000,000 shares of its common stock to be available for issuance under the Stock Purchase Plan. In 2001, 2000 and 1999 shares issued under the Stock Purchase Plan totaled 29,772, 32,296 and 32,794, respectively. Total proceeds to the Company for the issuance of these shares were $575,000, $311,000 and $258,000 in 2001, 2000 and 1999, respectively. The Company recorded compensation expense of $20,000, $3,000 and $20,000 in 2001, 2000 and 1999, respectively, due to nonqualified dispositions of stock acquired by employees under the Stock Purchase Plan.

In 1990 and 1991 the Company granted certain officers options to acquire 109,228 shares of common stock at an exercise price of $1.65 per share. All of these options had been exercised by December 31, 2000.

In 1996 the Company established the St. Mary Land & Exploration Company Stock Option Plan and the St. Mary Land & Exploration Company Incentive Stock Option Plan (collectively, the "Option Plans"). The Option Plans grant options to purchase shares of the Company's common stock to eligible employees, contractors, and current and former members of the Board of Directors. In 2001 the stockholders approved an increase in the number of shares of the Company's common stock reserved for issuance under the Option Plans from 3,300,000 shares to 4,300,000 shares. In 1999 the Company granted 623,492 options at an exercise price of $12.38 per share, and 7,660 options were exercised under the Option Plans. In 2000 the Company granted 653,848 options at an exercise price of $33.31 per share, and 589,220 options were exercised under the Option Plans. In 2001 the Company granted 175,729 options at an exercise price of $15.93 per share and 221,280 options at an exercise price of $21.19 per share. During 2001 190,289 options were exercised under the Option Plans. All options granted to date under the Option Plans have been granted at exercise prices equal to the respective market prices of the Company's common stock on the grant dates.

A summary of the status of the Company's Stock Option Plans, including the 1990 and 1991 options and changes during the last three years follows:

	For the Years Ended December 31,					
	2001		2000		1999	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,986,124	$ 18.95	1,998,254	$ 11.63	1,442,436	$ 11.28
Granted	397,009	18.86	653,848	33.31	623,492	12.38
Exercised	187,810	11.57	619,220	11.05	17,660	4.95
Forfeited	43,648	26.00	46,758	11.74	50,014	13.21
Outstanding at end of year	2,151,675	19.42	1,986,124	18.95	1,998,254	11.63
Options exercisable at year end	1,418,404	17.09	1,150,196	15.00	651,876	10.36
Weighted average fair value of options granted during the year	$ 8.36		$ 14.75		$ 5.13	

A summary of additional information related to the options outstanding as of December 31, 2001 follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 9.25 - $ 10.25	431,740	5.3 years	$ 9.63	431,740	$ 9.63
12.38 - 14.69	585,311	7.6 years	12.56	462,543	12.61
15.93 - 21.19	509,132	9.0 years	18.56	211,375	18.14
33.31 - 33.31	625,492	9.0 years	33.31	312,746	33.31
Total	2,151,675	7.9 years	19.42	1,418,404	17.09

SFAS No. 123 establishes a fair value method of accounting for stock-based compensation plans either through recognition or disclosure. The Company accounts for stock-based compensation under APB No. 25 and has elected to adopt SFAS No. 123 through compliance with the disclosure requirements set forth in the Statement. Because the exercise price of the Company's employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recognized under APB No. 25. Pro forma information regarding net income and earnings per share is required by SFAS No. 123 and has been determined as if the Company had accounted for its employee stock options under the fair value method of that Statement.

The fair value of options is measured at the date of grant using the Black-Scholes option-pricing model. The fair value of options granted in 2001 was estimated using the following weighted-average assumptions: risk-free interest rate of 4.35%; dividend yield of 0.53%; volatility factor of the expected market price of the Company's common stock of 49.79%; and expected life of the options of 4.8 years. The fair value of options granted in 2000 was estimated using the following weighted-average assumptions: risk-free interest rate of 5.14%; dividend yield of 0.32%; volatility factor of the expected market price of the Company's common stock of 47.11%; and expected life of the options of 4.8 years. The fair value of the options granted in 1999 was estimated using the following weighted-average assumptions: risk-free interest rate of 6.42%; dividend yield of 0.82%; volatility factor of the expected market price of the Company's common stock of 41.52%; and expected life of the options of 4.8 years.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because the Company's employee stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, it is management's opinion that the existing models do not necessarily provide a reliable single measure of the fair value of St Mary's employee stock options.

For purposes of pro forma disclosures, the estimated fair values of the options is amortized to expense over the options' vesting periods. Had compensation cost been determined based on the fair value at grant dates for stock option awards consistent with SFAS No. 123, the Company's net income (loss) and earnings (loss) per share would have been reduced to the pro forma amounts indicated below:

		Pro Forma for the Years Ended December 31,		
		2001	2000	1999
		(In thousands, except per share amounts)		
Net income (loss)	As reported	$ 40,459	$ 55,620	$ 82
	Pro forma	$ 37,569	$ 52,515	$ (1,530)
Basic earnings (loss) per share	As reported	$ 1.45	$ 2.00	$ -
	Pro forma	$ 1.34	$ 1.89	$ (0.07)
Diluted earnings (loss) per share	As reported	$ 1.42	$ 1.97	$ -
	Pro forma	$ 1.32	$ 1.86	$ (0.07)

The effects of applying SFAS No. 123 in the pro forma disclosure are not necessarily indicative of actual future amounts, and SFAS No. 123 does not apply to awards granted prior to 1995. Additional awards in future years are anticipated.

8. Pension Benefits

The Company's employees participate in a non-contributory pension plan covering substantially all employees who meet age and service requirements (the "Qualified Pension Plan"). The Company also has a supplemental non-contributory pension plan covering certain management employees (the "Nonqualified Pension Plan"). The Company's disclosures about pension benefits are as follows:

	For the Years Ended December 31,	
	2001	2000
	(In thousands)	
Change in benefit obligations:		
Benefit obligation at beginning of year	$ 3,054	$ 2,588
Service Cost	323	257
Interest Cost	317	193
Actuarial gain	1,485	190
Benefits paid	(81)	(174)
Benefit obligation at end of year	$ 5,098	$ 3,054
Change in plan assets:		
Fair value of plan assets at beginning of year	$ 1,775	$ 1,592
Actual return on plan assets	(13)	(1)
Employer contribution	361	358
Benefits paid	(81)	(174)
Fair value of plan assets at end of year	$ 2,042	$ 1,775
Funded Status	$(3,056)	$(1,279)
Unrecognized net actuarial gain	2,326	888
Unrecognized prior service cost	(20)	(28)
Accrued benefit cost	$ (750)	$ (419)

The Company's Nonqualified Pension Plan was the only pension plan with an accumulated benefit obligation in excess of plan assets. The plan's accumulated benefit obligation was $685,000 at December 31, 2001, and $357,000 at December 31, 2000. There are no plan assets in the nonqualified plan due to the nature of the plan.

Assumptions used in the measurement of the Company's benefit obligation are as follows:

	For the Years Ended December 31,	
	2001	2000
Weighted-average assumptions:		
Discount rate	7.25%	7.5%
Expected return on plan assets	8.0%	8.0%

Rate of compensation increase	5.0%	5.0%

	For the Years Ended December 31,		
	2001	2000	1999
	(In thousands)		
Components of net periodic benefit cost:			
Service cost	$ 323	$ 257	$ 178
Interest cost	317	193	172
Expected return on plan assets	(129)	(119)	(88)
Amortization of prior service cost	(8)	(7)	(7)
Amortization of net actuarial loss	188	36	90
Net periodic benefit cost	$ 691	$ 360	$ 345

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Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of 10% of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

9. Investment in Russian Joint Venture:

In February 2000 St. Mary exercised its option to convert its Khanty Mansiysk Oil Corporation ("KMOC") production payment receivable into common stock of KMOC. In July 2000 the Company finalized a negotiated value for the receivable that equated to 21,583 shares of KMOC common stock under the terms of the original agreement. In December 2000 the Company sold 14,662 of these shares for proceeds of $6,157,000, net of transaction costs and recognized a net gain of $2,156,000.

Subsequent to December 31, 2001 the Company sold its remaining shares of KMOC common stock for proceeds of $2,772,000 and recorded a gain of $838,000.

10. Derivative Instruments

The Company realized a net loss of $21,102,000 from derivative contracts for the year ended December 31, 2001, a net loss of $33,641,000 for the year ended December 31, 2000 and a net gain of $2,561,000 for the year ended December 31, 1999. All of these amounts are included in oil and gas production operating revenues in the consolidated statement of operations.

Including hedges entered into since December 31, 2001 the Company has the following commodity swap contracts in place to hedge cash flow and reduce the impact of oil and gas price fluctuations:

Product	Average Volumes/month	Quantity Type	Fixed Price	Duration
Natural Gas	1,467,000	MMBtu	$ 2.84	01/02 - 12/02
Natural Gas	168,000	MMBtu	$ 3.01	01/03 - 12/03
Natural Gas	59,000	MMBtu	$ 3.04	01/04 - 12/04
Oil	88,400	Bbls	$ 24.69	01/02 - 12/02
Oil	49,800	Bbls	$ 22.67	01/03 - 12/03

This table excludes commodity positions with Enron North America Corp, which filed for bankruptcy protection in December 2001. The Company's unrealized discounted hedge gain due from Enron had grown to $4,473,000 at the end of November 2001. As of November 13, 2001, the Company believed the Enron contracts it owned became ineffective under SFAS No. 133 due to lack of correlation for counterparty risk. Accordingly, the Company adjusted the fair value downward to the reduced estimated fair value. A net non-cash loss of $1,779,000 from counterparty ineffectiveness was offset by a $45,000 gain from hedge ineffectiveness and $161,000 of amortization of other comprehensive income from the Enron contracts. The net amount is the activity recorded for the year ended December 31, 2001 and is reported as unrealized derivative loss in the consolidated statement of operations. The Company will amortize the unrealized hedge gain from these Enron contracts over the next two years. Unrealized derivative gain in the consolidated statements of operations will reflect amortization of $2,786,000 over the next twelve months offset by a deferred tax provision. The Company took all legal steps to preserve its rights under these contracts and sold its claim at a discounted price in February 2002.

As noted in the table above, the last of these contracts will expire by December 31, 2004. On December 31, 2001 the estimated fair value of contracts designated and qualifying as cash flow hedges under SFAS No. 133 was an asset of $8,119,000. The Company will reclassify this amount to gains or losses included in oil and gas production operating revenues as the hedged production quantity is produced. Based on current prices the net amount of existing unrealized after-tax gain as of December 31, 2001 to be reclassified to oil and gas production operating revenues in the next twelve months would be $7,076,000. The Company anticipates that all original forecasted transactions will occur by the end of the originally specified time periods.

11. Disclosures About Oil and Gas Producing Activities:

Costs Incurred in Oil and Gas Producing Activities:

Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Years Ended December 31,		
	2001	2000	1999
	(In thousands)		
Development costs	$ 98,617	$ 48,996	$ 22,166
Exploration	24,506	17,012	20,809
Acquisitions:			
Proved	41,188	53,482	33,080
Unproved	18,552	5,694	15,129
Total	$ 182,863	$ 125,184	$ 91,184

Oil and Gas Reserve Quantities (Unaudited):

The reserve information as of December 31, 2001, 2000, and 1999 was prepared by Ryder Scott Company and St. Mary. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods.

Presented below is a summary of the changes in estimated domestic reserves of the Company:

	For the Years Ended December 31,					
	2001		2000		1999	
	Oil or Condensate	Gas	Oil or Condensate	Gas	Oil or Condensate	Gas
	(MBbl)	(MMcf)	(MBbl)	(MMcf)	(MBbl)	(MMcf)
Total proved reserves:						
Developed and undeveloped:						
Beginning of year	20,950	225,975	18,900	207,642	8,614	132,605
Revisions of previous estimates	(1,334)	(16,421)	210	(1,172)	3,308	(10,445)
Discoveries and extensions	3,131	59,830	1,707	37,702	2,062	43,501
Purchases of minerals in place	3,774	13,086	3,149	21,689	6,323	65,129
Sales of reserves	(418)	(1,748)	(618)	(1,540)	(24)	(343)
Production	(2,434)	(39,491)	(2,398)	(38,346)	(1,383)	(22,805)
End of year (a)	23,669	241,231	20,950	225,975	18,900	207,642
Proved developed reserves:						
Beginning of year	19,006	192,472	16,688	169,379	7,723	112,189
End of year	20,679	205,637	19,006	192,472	16,688	169,379

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(a) At December 31, 2001, 2000, and 1999, includes approximately 869, 1,199 and 1,802 MMcf, respectively, representing the Company's underproduced gas balancing position.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited):

SFAS No. 69, "Disclosures About Oil and Gas Producing Activities," prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying benchmark prices and costs, including transportation and basis differential, in effect at year-end to the year-end estimated quantities of oil and gas to be produced in the future. Estimated future income taxes are computed using current statutory income tax rates, including consideration for estimated future statutory depletion and alternative fuels tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the Securities and Exchange Commission. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process. The following prices, adjusted for transportation and basis differentials, were used in the calculation of the standardized measure:

	For the Years Ended December 31,		
	2001	2000	1999
Gas (per Mcf)	$ 2.502	$ 8.857	$ 2.186
Oil (per Bbl)	$ 18.113	$ 25.439	$ 23.847

The following summary sets forth the Company's future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in SFAS No. 69:

	For the Years Ended December 31,		
	2001	2000	1999
	(In thousands)		
Future cash inflows	$1,020,948	$2,648,108	$ 900,199
Future production and development costs	(444,608)	(570,711)	(344,350)
Future income taxes	(140,271)	(727,929)	(150,239)
Future net cash flows	436,069	1,349,468	405,610
10% annual discount	(154,192)	(630,984)	(144,296)
Standardized measure of discounted future net cash flows	$281,877	$718,484	$ 261,314

The principle sources of change in the standardized measure of discounted future net cash flows are as follows:

	For the Years Ended December 31,		
	2001	2000	1999
	(In thousands)		
Standardized measure, beginning of year	$ 718,484	$ 261,314	$ 101,946
Sales of oil and gas produced, net of production costs	(170,074)	(183,586)	(53,814)
Net changes in price and production costs	(820,253)	772,910	82,976
Extensions, discoveries and other, net of production costs	71,265	203,786	76,198
Purchase of minerals in place	29,267	104,883	105,728
Development costs incurred during the year	35,736	12,436	5,816
Changes in estimated future development costs	(8,370)	351	(25,281)
Revisions of previous quantity estimates	(17,593)	306	10,976
Accretion of discount	109,912	33,871	11,474
Sales of reserves in place	(10,548)	(3,329)	(542)
Net change in income taxes	298,717	(357,780)	(76,907)
Other	45,334	(126,678)	22,744
Standardized measure, end of year	$ 281,877	$ 718,484	$ 261,314

12. Quarterly Financial Information (Unaudited):

The Company's quarterly financial information for fiscal 2001 and 2000 is as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share data)			
Year Ended December 31, 2001:				
Total revenue	$ 68,347	$ 55,776	$ 42,656	$ 40,690
Less: costs and expenses	36,626	32,804	37,129	38,998
Operating income	$ 31,721	$ 22,972	$ 5,527	$ 1,692
Income before income taxes	$ 31,874	$ 23,119	$ 5,595	$ 1,700
Net income	$ 20,393	$ 14,234	$ 4,861	$ 971
Net income per common share:				
Basic	$ 0.72	$ 0.51	$ 0.17	$ 0.04
Diluted	$ 0.71	$ 0.50	$ 0.17	$ 0.03
Dividends paid per share	$ -	$ 0.05	$ -	$ 0.05
Year Ended December 31, 2000:				
Total revenue	$ 37,411	$ 46,822	$ 54,314	$ 57,119

Less: costs and expenses	25,201	22,996	26,151	32,768
Operating income	$ 12,210	$ 23,826	$ 28,163	$ 24,351
Income before income taxes	$ 12,350	$ 23,966	$ 28,390	$ 24,581
Net income	$ 7,886	$ 14,597	$ 17,139	$ 15,998
Net income per common share:				
Basic	$ 0.29	$ 0.53	$ 0.61	$ 0.57
Diluted	$ 0.29	$ 0.52	$ 0.60	$ 0.56
Dividends paid per share	$ 0.025	$ 0.025	$ 0.025	$ 0.025

13. Subsequent Events (Unaudited) :

In March 2002 the Company issued in a private placement a total of $100,000,000 of its 5.75% senior convertible notes due 2022 (the "Notes") with a 1/2% contingent interest provision. The Company received net proceeds of $96,700,000 after deducting the initial purchasers' discount and estimated offering expenses payable by the Company. The notes are general unsecured obligations and rank on a parity in right of payment with all existing and future senior indebtedness and other general unsecured obligations. They are senior in right of payment with all future subordinated indebtedness. The Notes are convertible into the Company's common stock at a conversion price of $26.00 per share, subject to adjustment. The Company can redeem the Notes with cash in whole or in part at a repurchase price of 100% of the principal amount plus accrued and unpaid interest beginning on March 20, 2007. The note holders have the option of redeeming the Notes for cash at 100% of the principal amount plus accrued and unpaid interest upon (1) a change in control or (2) on March 20, 2007, March 15, 2012 and March 15, 2017. On March 20, 2007 the Company may pay the repurchase price with cash, shares of its common stock or any combination of cash and its common stock. St. Mary is not restricted from paying dividends, incurring debt, or issuing or repurchasing its securities under the indenture. There are no financial covenants in the indenture. The Company used a portion of the net proceeds from the Notes to repay its credit facility balance and will use the remaining net proceeds to fund a portion of its 2002 capital budget.

SIGNATURES

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

ST. MARY LAND & EXPLORATION COMPANY
(Registrant)

Date: March 25, 2002

By: /s/ MARK A. HELLERSTEIN
Mark A. Hellerstein
President, Chief Executive Officer
and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ THOMAS E. CONGDON * Thomas E. Congdon	Chairman of the Board of Directors	March 25, 2002
/s/ MARK A. HELLERSTEIN * Mark A. Hellerstein	President, Chief Executive Officer and Director	March 25, 2002
/s/ RONALD D. BOONE * Ronald D. Boone	Executive Vice President, Chief Operating Officer and Director	March 25, 2002
/s/ RICHARD C. NORRIS * Richard C. Norris	Vice President-Finance, Secretary and Treasurer	March 25, 2002
/s/ GARRY A. WILKENING * Garry A. Wilkening	Vice President-Administration and Controller	March 25, 2002

Signature	Title	Date
/s/ LARRY W. BICKLE * Larry W. Bickle	Director	March 25, 2002
/s/ DAVID C. DUDLEY * David C. Dudley	Director	March 25, 2002
/s/ ROBERT L. NANCE * Robert L. Nance	Director	March 25, 2002
/s/ AREND J. SANDBULTE * Arend J. Sandbulte	Director	March 25, 2002
/s/ JOHN M. SEIDL * John M. Seidl	Director	March 25, 2002
/s/ WILLIAM J. GARDINER * William J. Gardiner	Director	March 25, 2002
/s/ JACK HUNT * Jack Hunt	Director	March 25, 2002

* By: /s/ MARK A. HELLERSTEIN March 25, 2002

Mark A. Hellerstein
(as attorney-in-fact for each of the persons indicated)

EXHIBIT 23.1

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our report included in this Form 10-K/A into St. Mary Land & Exploration Company and subsidiaries previously filed Form S-8 Registration Statement Nos. 033-61850, 333-30055, 333-58273 and 333-35352.

/s/ ARTHUR ANDERSEN LLP

Denver, Colorado,
March 22, 2002.

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K/A of St. Mary Land and Exploration Company for the year ended December 31, 2001. We hereby further consent to the use of information contained in our reports, as of January 1, 2002, 2001 and 2000 setting forth the estimates of revenues from St. Mary Land & Exploration Company's oil and gas reserves. We further consent to the incorporation by reference thereof into St. Mary Land & Exploration Company's Form S-8 (Registration Statement No. 033-61850), Form S-8 (Registration Statement No. 333-30055), Form S-8 (Registration Statement No. 333-58273), and Form S-8 (Registration Statement No. 333-35352).

Very truly yours,

/s/ RYDER SCOTT COMPANY, L.P.

Ryder Scott Company, L.P.

Denver, Colorado,
March 25, 2002.