UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

[x] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2004
or
[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission file number 001-31539

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 700, 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:

Title of each class	Name of each exchange on which registered
Common Stock, $.01 par value	New York Stock Exchange

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

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. [ ]

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

The aggregate market value of 28,070,421 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the common stock on June 30, 2004, the last business day of the registrant's most recently completed second fiscal quarter, of $35.65 per share as reported on the New York Stock Exchange was $1,000,710,509. Shares of common stock held by each director and executive officer and by each person who owns 10 percent 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 February 15, 2005, the registrant had 28,798,362 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required by Items 10, 11, 12, 13 and 14 of Part III is incorporated by reference from portions of the registrant's definitive proxy statement relating to its 2004 annual meeting of stockholders to be filed within 120 days after December 31, 2004.

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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". Throughout this document we make statements that are classified as "forward-looking". Please refer to the "Cautionary Statement about Forward-Looking Statements" section of this document for an explanation of these types of statements.

ITEM 1. BUSINESS

Background

We are an independent oil and gas company engaged in the exploration, exploitation, development, acquisition and production of natural gas and crude oil. We were founded in 1908 and incorporated in Delaware in 1915. Our primary objective is to invest in oil and gas producing assets that result in a superior return on equity while preserving underlying capital, resulting in a return on equity to stockholders that reflects capital appreciation as well as the payment of cash dividends. Our operations are focused in the following five core operating areas in the United States:

- the Mid-Continent region in western Arkansas, Oklahoma and northern Texas, primarily in the Anadarko and Arkoma basins, with significant activity in the Northeast Mayfield field;

- the Rocky Mountain region consisting of the Williston Basin in eastern Montana and western North Dakota and the Powder River, Green River, Wind River and Big Horn basins in Wyoming. The most recent activity in the Rockies includes drilling in the Middle Bakken formations, continued exploration in the Red River formation, and the development of coalbed methane reserves in the Hanging Woman Basin;

- the ArkLaTex region that spans northern Louisiana and southern Arkansas, Mississippi and eastern Texas, with the most recent activity drilling horizontal wells in the James and Pettet Limestones;

- the Gulf Coast region, including the Judge Digby field and our fee property in St. Mary Parish, Louisiana;

- the Permian Basin in eastern New Mexico and western Texas; included in this area is the Parkway Delaware Unit and the East Shugart Delaware Unit in New Mexico.

As of December 31, 2004, we had estimated proved reserves of approximately 56.6 MMBbl of oil and 319.2 Bcf of natural gas, or a total of 658.6 BCFE with a PV-10 value of $1.5 billion. Of these reserves, 85 percent were proved developed and 52 percent were crude oil. This represents an increase in reserve volumes of 11 percent and a 17 percent increase in PV-10 value from a year earlier. For the year ended December 31, 2004, we produced 75.4 BCFE representing average daily production of 206.0 MMCFE, a two percent decrease from 2003. Our reserve replacement in 2004 was 190 percent of production. Included in the proved reserve total at December 31, 2004 is 9.4 BCFE in our coalbed methane projects in the Hanging Woman Basin and the Atlantic Rim field.

We attempt to focus our resources in selected domestic basins where we believe 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, including non-conventional gas plays in the Rocky Mountain region. In 2004 we spent $228.8 million in capital expenditures related to drilling activities, $76.7 million on acquisition of oil and gas properties and $7.9 million on leasing activity.

We measure and rank our investment decisions based on their risk-adjusted estimated internal rate of return and return on investment. In 2004 all acquisitions were funded with available cash and funding from our revolving credit facility. When we issue stock for the acquisition of properties or a corporate entity, we base our investment decision primarily on the transaction's impact on net asset value per share.

We divest selected non-core assets when market conditions and prices are attractive, and we will continue to evaluate such opportunities in the future. For example, in 2004 we sold certain oil and gas properties for total proceeds of approximately $2.8 million, resulting in a gain of $1.8 million.

We seek to develop our existing property base and acquire acreage with additional potential in our core areas. From January 1, 2002, through December 31, 2004, we participated in the drilling or recompletion of 777 gross wells with a success rate of 84 percent. During that same period we added estimated proved reserves of 537.0 BCFE at an average finding cost of $1.38 per MCFE. Our average annual production replacement was 259 percent during this three-year period, and our production has grown from an average daily rate of 150.8 MMCFE per day in 2002 to 206.0 MMCFE per day in 2004. Production in December 2004 averaged 216.7 MMCFE per day.

As of December 31, 2004, we had an acreage position of 1,969,808 gross (1,037,522 net) acres of which 1,184,086 gross (722,396 net) acres were undeveloped. Our current leasehold position represents a 2 percent decrease on a gross acre basis and a 5 percent decrease on a net acre basis from 2003. In addition to the leased acreage position, we own 24,914 net acres of fee properties in St. Mary Parish, Louisiana and mineral servitudes representing 14,316 gross (9,514 net) acres in other portions of Louisiana.

For 2005 we have budgeted capital expenditures of $293 million for ongoing development, exploitation and exploration programs in our core operating areas and $125 million for the acquisition of oil and gas properties.

Our principal offices are located at 1776 Lincoln Street, Suite 700, 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 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, leasehold, and non-conventional gas prospects. We believe that our significant leasehold position is a strategic asset. Our senior technical managers, each possessing over 15 years of industry experience, head up fully-staffed regional technical offices that are supported by centralized administration from our Denver office. We believe that our long-standing presence, our application of technology, our established networks of

local industry relationships and our acreage holdings in our core operating areas provide us with a competitive advantage.

- 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, horizontal drilling, secondary recovery and specialized logging tools to enhance the potential of our existing properties. In 2004 we participated in the drilling or recompletion of 368 gross wells with an 88 percent success rate.

- Make Selective Acquisitions. We make selective 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 focus on relatively small transactions where we have specialized geologic knowledge or operating experience to enable us to acquire attractively priced properties. In addition, we pursue corporate acquisitions that we believe are accretive and capable of being integrated into the Company. In 2004, we acquired the stock of Goldmark Engineering, Inc., and in early 2005 we completed the acquisition of Agate Petroleum, Inc. Other examples of corporate acquisitions include our 1999 Nance Petroleum Corporation and King Ranch Energy, Inc. acquisitions, both of which were accomplished with the issuance of our common stock. The Flying J Oil & Gas Inc. et al. property acquisition transaction completed in 2003 was not a corporate acquisition. We used a combination of restricted stock, a loan to Flying J and options on our common stock to consummate this transaction. We have budgeted $125 million for acquisitions in 2005.

- Control Operations. We believe it is important to control geologic and operational decisions as well as the timing of those decisions. As of December 31, 2004, we operated 69 percent of our properties on a reserve volume basis and 66 percent on a PV-10 value basis. We are the operator of properties representing approximately 71 percent of our 2005 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. Our debt to total capitalization ratio was 22 percent at the end of December 2004.

Significant Developments since December 31, 2003

- o 2004 Acquisition of Oil and Gas Properties. Our total acquisitions of proved and unproved oil and gas properties in 2004 were $76.7 million. The two most significant acquisitions were the Goldmark Engineering, Inc. et al. acquisition that closed on November 1, 2004 for $23.3 million and the Border Company et al. acquisition that closed on December 15, 2004 for $37.8 million. The primary asset acquired in the Goldmark transaction was the operations and majority ownership in the Fourbear Field, located in the Big Horn Basin of Wyoming. We anticipate that the development program in this field will be quite active in 2005 and will include infill drilling, recompletion of additional pay zones, workovers and the possible employment of enhanced recovery techniques. The

Border Company acquisition primarily included a non-operated interest in the very active Elm Grove Field, located in Northern Louisiana where we expect to participate in numerous development locations.

- o Coalbed Methane Development. We realized our first commercial production for the Hanging Woman Basin coalbed methane project in 2004. Our total proved reserves at Hanging Woman Basin at the end of 2004 were 8 BCFE. During 2004 we drilled and completed 57 wells. The non-operated pipeline and compression station connecting the wells to the main trunk line became operational in mid-December 2004. The 2005 capital program for the Hanging Woman Basin development is currently budgeted at $24 million. We also participated in a coalbed methane development project at Atlantic Rim in the Green River Basin of Wyoming.

- o Increase in 2004 Year-End Reserves. Proved reserves increased 11 percent to 658.6 BCFE at December 31, 2004, from 593.7 BCFE at December 31, 2003. We added 52 BCFE through acquisitions, primarily in the Rocky Mountain and ArkLaTex regions, and 101 BCFE from drilling activities. There were net downward revisions of previous reserves totaling 10 BCFE. These downward revisions were the combination of a 16 BCFE increase resulting from price adjustments and a 26 BCFE decrease due to performance revisions. The 11 percent increase in reserves over last year is net of current year sales of oil and gas properties of 3 BCFE.

- o Drilling Results. The majority of the reserve additions attributed to drilling operations came from our Rocky Mountain and Mid-Continent regions. The increase in the Rockies can be attributed primarily to continued development of the Middle Bakken play. This is one of the most active plays in the United States. Currently concentrated in Montana, the play is thought to extend into North Dakota. As of year end, we have approximately 181,000 net acres leased in Richland County, Montana, and McKenzie and Billings Counties, North Dakota, of which we believe approximately 74,000 net acres is in the primary trend. The Red River formation continues to result in reserve additions in the Rockies as we take full advantage of 3-D seismic to identify multi-pay structures. Mid-Continent reserve additions were primarily from the continued exploitation and development of the Northeast Mayfield area, although the results were less significant than in the prior year. The finding costs resulting from the Mid-Continent area were higher than the Company average as a whole.

- o Repurchase of Common Stock. In February 2004, we repurchased 3,380,818 shares of our common stock from Flying J for a total of $91.0 million. We originally issued these shares to Flying J on January 29, 2003, in connection with our acquisition of oil and gas properties. We also loaned Flying J $71.6 million in connection with the property acquisition. Flying J used the proceeds from the share repurchase to repay the outstanding loan balance. The net $19.4 million difference was funded from our available cash and from borrowings under our credit facility. The amount funded from borrowings under our credit facility was repaid during the second quarter of 2004. In the third quarter of 2004, we re-initiated our stock repurchase program. Since that time we have repurchased a total of 489,300 shares of our common stock at an average cost of $33.39 per share. These repurchases were funded from available cash. As of December 31, 2004, the number of additional shares that may be repurchased under the program is 2,510,700.

Major Customers

During 2004, sales to Tesoro Refining and Marketing accounted for 20 percent of our total oil and gas production revenue. During 2003, sales to BP America Production Company accounted for 14 percent, sales to Midcoast Energy accounted for 13 percent and sales to Tesoro Refining and Marketing accounted for 11 percent of our total oil and gas production revenue. During 2002, there were no sales to individual customers that accounted for more than 10 percent of our total oil and gas production revenue.

Employees and Office Space

As of February 15, 2005, we had 256 full-time employees. None of our employees are subject to a collective bargaining agreement, and we consider our relations with our employees to be good. We lease approximately 47,400 square feet of office space in Denver, Colorado, for our executive and administrative offices, of which 9,500 square feet is subleased. We also lease approximately 18,600 square feet of office space in Tulsa, Oklahoma; approximately 11,700 square feet in Shreveport, Louisiana; approximately 13,700 square feet in Houston, Texas; and approximately 22,200 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. The majority of the value of our properties is subject to a mortgage under our credit facility, 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 leasehold.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during the colder winter months and decrease during the warmer summer months. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Crude oil and the demand for heating oil are also impacted with generally higher prices in the winter. Seasonal anomalies such as mild winters sometimes lessen these fluctuations.

Competition

The oil and gas industry is intensely competitive. This is particularly so in the acquisition of prospective oil and natural gas properties and oil and gas reserves. We believe that our leasehold position provides the foundation for a strong drilling program. Our competitive position also depends on our geological, geophysical and engineering expertise, and our financial resources. We believe that the location of our leasehold acreage, our exploration, drilling and production expertise and the experience and knowledge of our management and industry partners enable us to compete effectively in our core operating areas. Notwithstanding our talents and assets, we still face stiff competition from 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. Consequently, drilling equipment may be in short supply from time to time. Currently, access to incremental drilling equipment in certain regions is difficult.

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.

Energy Regulations. 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 Federal Energy Regulatory Commission 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.

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. Regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum product pipelines. In addition, 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, and 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 that differs materially from other natural gas producers and marketers with whom we compete.

Certain operations we conduct involve federal minerals that the Minerals Management Service administers. The MMS issues leases covering such lands through competitive bidding. These leases contain relatively standardized terms and require compliance with federal laws and detailed MMS regulations. 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 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 may not be able to 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.

Our anticipated coalbed methane gas production from the Hanging Woman Basin will be 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 in the Hanging Woman Basin requires state permits for the use of well-site pits and evaporation ponds for the disposal of produced water. 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 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.

Environmental Regulations. Our operations are subject to numerous existing federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations may require that permits be obtained 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, and limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, including areas containing endangered animal species. As a result, these laws and regulations may substantially increase the costs of

exploring, developing or producing oil and gas and may prevent or delay the commencement or continuation of a project. In addition, these laws and regulations may impose substantial clean-up, remediation and other obligations in the event of any discharges or emissions in violation of such laws and regulations.

To date we have not experienced any material adverse effect on our financial condition or results of operations from obligations under environmental laws and regulations. We believe that we are in substantial compliance with currently applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us.

Risk Factors

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.

Risks Related to Our Business

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. Any substantial or extended decline in the price of oil or gas would have a material adverse effect on us. It could reduce our cash flow and borrowing capacity, as well as the value and the amount of our oil and gas reserves.

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;
- worldwide economic conditions;
- the availability of transportation facilities;
- weather conditions; and
- actions of governmental authorities.

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 us.

Our future success depends on our ability to replace reserves.

Our future success depends on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. Our properties produce at a declining rate over time. In order to maintain current production rates we must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. We may do this even during periods of low oil and gas prices. 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 may not be able to acquire oil and gas properties that contain economically recoverable reserves or we may not be able to acquire such properties at acceptable prices. Without successful exploration or acquisition activities, our reserves, production and revenues will decline rapidly.

Our producing property acquisitions carry significant risks.

Successful property 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. A customary review of subject properties will not necessarily reveal all existing or potential problems.

In connection with our acquisitions, we may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties.

o Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

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

Integrating acquired properties and businesses involves a number of special risks, including 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. Therefore, we may not be able to realize all 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 $313 million for 2004, and we have budgeted total capital expenditures of $418 million in 2005. 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 unless we raise additional funds through debt or equity financing. Debt or equity financing, cash generated by operations or borrowing capacity may not be available to us in sufficient amounts or 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 stockholders. Debt financing could lead to us being more vulnerable to competitive pressures and economic downturns.

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 could incur substantial additional loans, which could negatively impact our financial condition, results of operations and business prospects.

As of December 31, 2004, we had $137 million in outstanding loans, including $100 million outstanding under our 5.75% Senior Convertible Notes due 2022. Our level of debt could have important consequences on our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures and other general business activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- detracting from our ability to successfully withstand a downturn in our business or the economy generally.

The occurrence of any one of these events could have a material adverse effect on our business, financial condition, results of operations and business prospects.

We may incur additional debt, including secured debt under our credit facility or otherwise, in order to make future acquisitions or to develop our properties. We may not be able to generate sufficient cash flow to pay the interest on additional debt. Future working capital, borrowings or equity financing may not be available to pay or refinance such debt.

In addition, our credit facility borrowing base is subject to periodic borrowing base redeterminations. We could be forced to repay a portion of our bank borrowings due to a downward redetermination of our borrowing base. We may not have sufficient funds to make such repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowing or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

We may not be able to obtain credit facility borrowing base redeterminations that adequately meet our anticipated financing needs.

Our current long-term credit facility with a group of banks has a maximum loan amount of $300 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. In October 2004 the banks conducted their normal semi-annual borrowing base redetermination that resulted in a borrowing base of $325 million. Since we pay commitment fees based on the unused portion of the borrowing base, we elected to retain a total loan commitment amount under the facility of $150 million to correspond with our projected funding requirements. Our next borrowing base redetermination is scheduled to occur by the end of April 2005. The banks may not agree to a borrowing base redetermination that is adequate for our planned financing requirements.

Our long term credit facility is scheduled to expire in January 2006. We anticipate renegotiating the terms of our facility in the first quarter of 2005 to ensure that we have a credit facility in place beyond the current expiry.

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 and the costs of carrying and retaining unproved properties 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 $1.9 million, $4.0 million and $2.4 million in 2004, 2003 and 2002, respectively.

Estimates of oil and gas reserves are not precise.

This report and other SEC filings by us contain estimates of our proved oil and gas reserves and the estimated future net revenues from those reserves. Actual results will likely vary from amounts estimated, and any significant negative variance could have a material adverse effect on our future results of operations.

Reserve estimates are based on various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent on many variables and therefore changes often occur as these variables evolve and commodity prices fluctuate. However, the likelihood of recovery of these reserves is considered more likely than not.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by us. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

As of December 31, 2004, approximately 15 percent of our estimated proved reserves were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved developed non-producing reserves will not be realized until some time in the future. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

You should not construe the present value of future net reserves, or PV-10, as the current market value of the estimated oil and natural gas reserves attributable to our properties. Management has based the estimated discounted future net cash flows from proved reserves 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 as of December 31, 2004, were estimated using a calculated weighted average sales price of $43.45 per barrel of oil (NYMEX) and $6.18 per Mcf of gas (Gulf Coast spot price). During 2004 our monthly average realized gas prices, excluding the effect of hedging, were as high as $7.27 per Mcf and as low as $4.90 per Mcf. For the same period our monthly average realized oil prices were as high as $51.21 per Bbl and as low as $32.26 per Bbl. 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 oil and 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 affects the timing of actual future net cash flows from proved reserves and thus their actual present value. In addition, the 10 percent discount factor, which we are required to use to calculate PV-10 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 report.

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. Shortages for equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. 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 may not 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; 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. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays which jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore on or develop our properties.

The wells we drill may not be productive and we may not 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 may not be able to economically produce oil or natural gas from all of them.

Our business is subject to operating and environmental risks and 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 risks and hazards. If any of these types of events occurs, we could sustain substantial losses.

Under certain limited circumstances we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur 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.

We maintain insurance against some, but not all, of these potential risks and losses. We have limited coverage for sudden environmental damages. We do not believe that insurance coverage for the full potential liability that could be caused by sudden environmental damages or insurance coverage for environmental damage that occurs over time is available at a reasonable cost. In addition, pollution and environmental risks generally are not fully insurable. Further, we may elect not to obtain other insurance coverage under circumstances where we believe that the cost of available insurance is excessive relative to the risks presented. Accordingly, we may be subject to liability or may lose substantial portions of certain properties in the event of environmental or other damages. If a significant accident or other event occurs and is not fully covered by insurance, it could have a material adverse effect on our financial condition and results of operations.

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.

In addition, hedging transactions using derivative instruments involve basis risk. Basis risk in a hedging contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

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. These 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. 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 may not be able to obtain bonds or other surety in all cases. Under limited circumstances, federal authorities may require any of our operations on federal leases to 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. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, may have a material adverse effect on our results of operations and financial condition. As a result, we may face material 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 shutting-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.

Ownership of working interests, royalty interests and other interests by a director and some of our officers 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, a director of St.

Mary, and two vice presidents of St. Mary own royalty interests in a number 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 St. Mary properties acquired or developed subsequent to the beginning of their employment with St. Mary.

Mr. Boone also owns 25 percent of Princeton Resources LLC, which owns the oil and gas working interests that he acquired as a result of his prior employment. Although Mr. Boone does not manage this entity, he may participate in any investment decisions made by it.

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, conflicts of interest may not always be resolved in our favor.

Risks Related to Our Common Stock

The price of our common stock may fluctuate significantly, which may result in losses for investors.

From January 1, 2003, to February 15, 2005, the last daily sale price of our common stock reported by the New York Stock Exchange ranged from a low of $23.83 per share to a high of $49.47 per share. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These include:

- changes in oil and natural gas prices;
- variations in quarterly drilling, recompletions, acquisitions and operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel; and
- future sales of our common stock.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future, and our stock price could decline as a result.

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 non-cumulative 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.

Under our stockholder rights plan, if the Board of Directors determines that the terms of a potential acquisition do not reflect the long-term value of St. Mary, 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. The existence of the plan may impede a takeover not supported by our board even though such takeover may be desired by a majority of our stockholders or may involve 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 February 15, 2005, we had 28,548,362 shares of common stock outstanding. Of the shares outstanding, approximately 28,234,000 shares were freely tradable without substantial restriction or the requirement of future registration under the Securities Act. Also as of that date, options to purchase 2,756,436 shares of our common stock were outstanding, of which 2,152,871 were exercisable. These options are exercisable at prices ranging from $9.25 to $41.74 per share. In addition, restricted stock units providing for the issuance of up to a total of 227,831 shares of our common stock were outstanding. Sales of substantial amounts of common stock, or a perception that such sales could occur, and the existence of options or restricted stock units to issue shares of common 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.

A director and his extended family may be able to control us.

Thomas E. Congdon, a director and our former Chairman of the Board, and members of his extended family owned greater than 10 percent of the outstanding shares of our common stock as of February 15, 2005. While no formal arrangements exist, these extended family members could 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 Board of Directors and stockholders.

We may not always pay dividends on our common stock.

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 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 the payment of dividends altogether. Our credit facility limits the annual dividend rate that we may pay to $0.20 per share.

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, the uncertain nature of the expected benefits from the acquisition of oil and gas properties, production rates and reserve replacement, the imprecise nature of oil and gas reserve estimates, drilling and operating service availability, unexpected drilling conditions and results, the risks of various exploration strategies, competition, the availability of economically attractive exploration and development and property acquisition opportunities and any necessary financing, 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.

Available Information

Our Internet website address is www.stmaryland.com. Through our website's financial information section we make available free of charge our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such material with, or furnish it to, the SEC.

We also make available through our website's corporate governance section our corporate governance guidelines, code of business conduct and ethics, and the charters for our Board of Directors' audit committee, compensation committee, executive committee and nominating and corporate governance committee. These documents are also available in print to any stockholder who requests them. Requests for these documents may be submitted to:

St. Mary Land & Exploration Company
Investor Relations
1776 Lincoln Street, Suite 700
Denver, Colorado 80203
Telephone: (303) 863-4322

Information on our website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this document.

Glossary

The terms defined in this section are used throughout this Annual Report on 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 beyond its known horizon.

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 or MCFE. Finding costs are calculated by dividing the amount of total capital expenditures for oil and gas activities, including the effect of asset retirement obligations, by the amount of estimated net proved reserves added through revisions of previous estimates, discoveries and purchases during the same period. The information for this calculation will be found in the disclosures about oil and gas producing activities in Item 15 of Part IV of this report.

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 amount of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Net acres or net wells. The sum of our 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 percent.

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 from an existing wellbore in another formation other than 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.

Reserve replacement percentage. The sum of reserve extensions and discoveries, reserve acquisition, and reserve revisions of previous estimates for a specified period of time divided by production for that same period of time.

Royalty. The share paid to the owner of mineral rights expressed as a percentage of gross income from oil and gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

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.

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 Rocky Mountain region; the Mid-Continent region; the ArkLaTex region; the Gulf Coast region; and the Permian Basin region. Information concerning each of our major areas of operations, and summary of our estimated proved reserves as of December 31, 2004, is shown below.

	Estimated Proved Reserves					
	Oil	Gas	MMCFE		PV-10 Value	
	(MBbl)	(MMcf)	Amount	Percent	(In thousands)	Percent

Rocky Mountain	46,762	75,335	355,907	54%	$ 748,916	50%
Mid-Continent	1,024	129,536	135,678	21%	335,028	22%
ArkLaTex	1,438	66,931	75,558	12%	173,190	12%
Gulf Coast	388	31,170	33,498	5%	120,591	8%
Permian Basin	6,962	6,754	48,527	7%	109,710	7%
Coalbed Methane	-	9,470	9,470	1%	13,688	1%
Total	56,574	319,196	658,638	100%	$ 1,501,123	100%

Rocky Mountain 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 since 1991. We have expanded this area into the Green River, Powder River, Big Horn and Wind River basins over the past three years. In November 2004, we acquired the stock of Goldmark Engineering, Inc. along with oil and gas properties from various Goldmark partners for $23.3 million of cash. The allocation of the purchase price for the net assets acquired was $29.4 million of proved reserves and unproved acreage, $1.2 million of cash, $753,000 of other assets, $446,000 of payables, a $2.8 million asset retirement liability, and a $4.8 million deferred tax liability. The Goldmark acquisition added approximately 31.9 BCFE of proved reserves as of the acquisition date.

Conventional oil and gas reserves in the Rocky Mountain region accounted for 54 percent of our estimated proved reserves as of December 31, 2004, or 356 BCFE, 87 percent of which were proved developed and 79 percent of which were oil.

Our office in Billings, Montana includes a 75-person staff. A significant portion of the exploration and development in the Rocky Mountain region 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 as well as the Middle Bakken horizontal dolomite play.

St. Mary spent $108.5 million on exploration, development and acquisitions in the Rocky Mountain region in 2004.

Our capital budget for the Rocky Mountain region now represents the largest portion of our drilling budget at approximately $121 million in 2005. This increase is a result of the increased development of the Middle Bakken formation, increased drilling associated with the Red River play, and a full year development plan for our Hanging Woman Basin coalbed methane project. We have approximately 150 wells planned and a risked budget of $24 million at Hanging Woman. The Bakken play, which has been primarily in Richland County, Montana, is now expanding to McKenzie and Billings Counties in North Dakota. We plan on drilling 30 wells in the Bakken during 2005 for total risked capital of

$30 million. The Red River formation continues to be a major portion of the budget with nine wells planned for $13 million. Our growth in Wyoming has resulted in an allocated capital budget of $26 million for participation in 69 gross wells in the Fourbear, Monument Lake, Red Lakes and Standard Draw fields. In the Rocky Mountain region, we have a working interest greater than 90 percent in 322 wells. Including the development of Hanging Woman Basin, we will be the operator of properties representing approximately 83 percent of our 2005 Rocky Mountain region capital budget.

The concentration of our value in the Rockies is at the East Putnam field in Richland County, Montana, and at the Rough Rider field in McKenzie County, North Dakota. Each of these fields represents two percent of total proved reserves and two percent of our PV-10 value. There are nine and 41 gross wells producing in these two fields, respectively, with our working interest varying from six to 100 percent. Following these fields, the other most significant fields are the Brush Lake, South Fork and Ridgelawn areas. Combined, these three fields represent five percent of our total reserves and PV10 value.

As of the end of 2004, the Hanging Woman Basin coalbed methane project had 8 BCFE of proved reserves representing one percent of our total proved reserves. We are in the early development stage. First production from the field began in mid-December 2004. We do not expect production from Hanging Woman to account for a material portion of total 2005 production volumes. Because of the dewatering time and the low production rates per well, it will take two to three years to develop the field to the point of having production volumes that are meaningful to our total production.

Mid-Continent Region. St. Mary has been active in the Mid-Continent region since 1973. Operations for the region are managed by our 42-person office in Tulsa, Oklahoma. 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 apply current 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 attempt to benefit from the continuing consolidation of operators in the basin as we pursue attractive opportunities to acquire properties.

We have ongoing exploration and development programs in the Anadarko and Arkoma basins of Arkansas, Oklahoma and Texas. The Mid-Continent region accounts for 21 percent of our estimated proved reserves as of December 31, 2004, or 136 BCFE, 88 percent of which were proved developed and 95 percent of which were natural gas. In 2004 our capital expenditures in the Mid-Continent were $104.0 million. We participated in drilling 108 gross wells in this region in 2004, 91 percent of which were completed as producers. We operated 36 of these drilling projects.

St. Mary's development and exploration budget in the Mid-Continent region for 2005 totals $87 million, down from $96 million in 2004. Included in the 2005 budget is $3 million of drilling associated with the Agate acquisition. The decrease in the budget is intended to focus investment in drilling with a higher potential of return. We plan to be the operator of properties representing approximately 80 percent of our capital budget in this region during 2005 and to utilize three to five drilling rigs throughout the year.

Approximately 23 percent of our 2005 Mid-Continent capital budget is allocated to deeper, higher-potential wells in the Morrow/Springer formations, and 25 percent is allocated to the Atoka formations at the Northeast Mayfield field in Beckham County, Oklahoma on the southern edge of the Anadarko Basin. We have allocated 48 percent of the drilling activities budget for low-to-medium-risk development in the Granite Wash, Osborne, Cottage Grove, Cromwell / Wapanucka, Woodford and Spiro formations. With our recently completed

acquisition of Agate Petroleum, Inc., we have allocated 4 percent of our drilling budget to development of the Hartshorne formation.

The Northeast Mayfield area is the largest concentration of our reserves in the Mid-Continent. This field represents approximately 32 BCFE or five percent of our proved reserves and $82.7 million, or approximately 6 percent of our total PV-10 value. Our average working interest in this field is 24 percent, and we have an interest in approximately 73 gross wells of which we operate 42 percent.

Other significant fields in the Mid-Continent region are the Centrahoma field located in Coal County, Oklahoma, in the Arkoma Basin and the Constitution field in Jefferson County, Texas. Centrahoma represents three percent of total proved reserves and $37.1 million or two percent of total PV-10 value, and the Constitution field represents one percent of total proved reserves and $28 million of PV-10 value. We operate 85 percent of the Centrahoma field but none of the 7 gross wells in Constitution field. The other most significant field in the Mid-Continent region is the Elk City field in Beckham County, Oklahoma, representing two percent of proved reserves and two percent of total PV10 value. We operate 18 percent of the wells in Elk City and have an average working interest of approximately 13 percent.

ArkLaTex Region. Our 18-person office in Shreveport, Louisiana, manages St. Mary's operations in the ArkLaTex region. The ArkLaTex region accounts for 12 percent of our estimated proved reserves as of December 31, 2004, or 76 BCFE; 83 percent of which were proved developed and 89 percent were natural gas. We also own rights to over 6,000 square miles of proprietary 2-D seismic data in the region. Many of the Shreveport office's successful exploration and development programs have derived from niche acquisitions. 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. We believe the recent acquisition of non-operated producing working interests in the Elm Grove field, consisting of 14.5 BCFE and $34 million of PV-10 value, will provide us a foothold to grow our interest in this area.

Our holdings in the ArkLaTex region are comprised of interests in approximately 538 producing gross wells, including 101 wells operated by us; interests in leases totaling approximately 149,000 gross acres; and mineral servitudes totaling approximately 14,300 gross acres. Our capital expenditures in this region in 2004 were $67.3 million, including $37.6 million for acquisitions. Following our ownership in the Elm Grove field, the next most significant concentration of properties is the Box Church field, which includes 16 BCFE of proved reserves and working interests in 33 gross wells, all of which we operate.

In 2005 we will grow our drilling capital budget in the ArkLaTex to $34 million. These capital dollars are budgeted for horizontal wells in the James and Pettet Limestones and other tight sands plays and development of the Elm Grove and Travis Peak / Cotton Valley plays in East Texas. The budget reflects us as operator for 46 percent of estimated expenditures.

Gulf Coast 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 24,914 acres of fee lands yielded $5.5 million of gross oil and gas royalty revenue in 2004. Our Gulf Coast region presence increased significantly in 1999 with the acquisition of King Ranch Energy, Inc. Including the Louisiana fee lands, the Gulf Coast region accounts for five percent of our estimated proved reserves as of December 31, 2004, or 33 BCFE, 93 percent of which were proved developed and 31 BCFE were natural gas.

Our 18-person team based in Houston, Texas manages St. Mary's diverse activities in our Gulf Coast and Permian Basin regions. Our exploration and development budget in the Gulf Coast region for 2005 is $41 million which consists of activity both onshore and offshore in Texas and Louisiana. We will operate properties representing approximately 33 percent of this amount.

The most significant field in the Gulf Coast region is the Judge Digby Field, located outside Baton Rouge, Louisiana, in Point Coupee Parish. As of the end of December 2004, this field represented slightly less than three percent of our total PV-10 value with 13.5 BCFE of proved reserves. Production from the Judge Digby field totaled 3.6 BCFE in 2004.

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. The use of 3-D seismic imaging of existing fields and advanced secondary recovery programs are substantially increasing oil recoveries in this Basin. Our holdings in the Permian Basin resulted from a series of property acquisitions since 1995. 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 additional secondary recovery projects. The Permian Basin region accounted for 49 BCFE, or 7 percent of our estimated proved reserves as of December 31, 2004. The Permian reserves are 63 percent proved developed and 86 percent are oil.

The Parkway Delaware waterflood project, located in Eddy County, New Mexico, represents 19 BCFE or three percent of our proved reserves. The East Shugart Delaware Unit is a pilot waterflood located in Lea and Eddy Counties, New Mexico that is analogous to the Parkway Delaware Unit and is comprised of 16 BCFE of total proved reserves. Production from the Permian Basin properties represented 3.1 BCFE or 4 percent of the total production for the Company in 2004.

Our Permian Basin capital budget for 2005 is $10 million of which we anticipate spending 79 percent on properties we operate. We plan to drill 11 infill wells at Parkway Delaware and eight wells at East Shugart. Our capital budget also has seven recompletion projects scheduled at Parkway Delaware. East Shugart is still in a pilot phase and is moving into full development of the flood in 2005.

Acquisitions and Divestitures

We spent a total of $76.7 million on acquisitions of proved and unproved oil and gas properties in 2004. The two most significant acquisitions were the Goldmark and Border Company acquisitions. On November 1, 2004, we acquired the stock of Goldmark Engineering, Inc. and proved and unproved oil and gas properties from various Goldmark partners for $23.3 million of cash. The oil and gas properties in the Goldmark acquisition are located primarily in the Fourbear field in the Big Horn Basin of Wyoming. On December 15, 2004, we acquired proved and unproved oil and gas properties from Border Company in and around the Elm Grove field located in Louisiana for $37.8 million of cash. We made various other smaller acquisitions in 2004 as well. In the aggregate, we purchased 52 BCFE of proved reserves in 2004.

Significant acquisitions prior to 2004 include the acquisitions of oil and gas properties in the Rocky Mountain region from Flying J Oil & Gas Inc. in January 2003 and from Burlington Resources in December 2002.

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, 2004, as prepared by both Ryder Scott Company and Netherland, Sewell & Associates, Inc., both of which are independent petroleum engineering firms, and us. For the periods presented, Ryder Scott Company evaluated properties representing a minimum of 80 percent of the total PV-10 value of our conventional reserves, and we evaluated the remainder. The proved oil and gas reserves prepared by Netherland Sewell in 2004 consist of the coalbed methane developments at Hanging Woman Basin and Atlantic Rim. As of December 31, 2004, the PV-10 of proved reserves, prepared by Netherland Sewell, was less than one percent of our total PV-10 reserve value. 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. You should read the following table along with the section entitled "Risk Factors - Risks Related to Our Business - Estimates of oil and gas reserves are not precise."

	As of December 31,		
Proved Reserves Data:	2004	2003	2002
Oil (MBbl)	56,574	47,787	36,119
Gas (MMcf)	319,196	307,024	274,172
MMCFE	658,638	593,744	490,887
PV-10 value, without tax effect (in thousands) (1)	$ 1,501,123	$ 1,278,165	$ 824,808
Standardized measure of discounted future net cash flows (in thousands)	$ 1,033,938	$ 859,956	$ 581,862

Proved developed reserves	85%	89%	88%
Reserve replacement	190%	293%	306%
Reserve life (years) (2)	8.7	7.7	8.9

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(1) PV-10 value as of December 31, 2004, was calculated using the weighted-average sales price of $40.06 per barrel of oil and $5.80 per Mcf of gas. These prices are based on NYMEX prices for oil and a Gulf Coast spot price for gas in effect on December 31, 2004, and are then adjusted for transportation, quality and basis differentials.

(2) Reserve life represents the estimated proved reserves at the dates indicated divided by actual production for the preceding 12-month period.

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, 2004	2003	2002
Operating data:			
Net production:			
Oil (MBbl)	4,799	4,541	2,815
Gas (MMcf)	46,598	49,663	38,164
MMCFE	75,393	76,909	55,055
Average net daily production:			
Oil (Bbl)	13,113	12,441	7,713
Gas (Mcf)	127,316	136,062	104,558
MCFE	205,992	210,709	150,836
Average realized sales price (1):			
Oil (per Bbl)	$ 32.53	$ 26.96	$ 25.34
Gas (per Mcf)	$ 5.52	$ 4.89	$ 3.00
Per MCFE	$ 5.48	$ 4.75	$ 3.37
Additional per MCFE data:			
Lease operating expense	$ 0.81	$ 0.77	$ 0.66
Transportation costs	$ 0.10	$ 0.09	$ 0.06
Production taxes	$ 0.36	$ 0.29	$ 0.20
General and administrative	$ 0.29	$ 0.28	$ 0.25
Depreciation, depletion, amortization and liability accretion	$ 1.22	$ 1.07	$ 0.99

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(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, 2004, we had working interests in 1,613 gross (727 net) productive oil wells and 2,068 gross (479 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

All of our drilling activities are conducted on a contract basis with independent drilling contractors. We do not own any drilling equipment. 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, 2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	50	18.08	36	14.88	26	11.52
Gas	180	53.23	140	43.79	103	38.89
Non-productive	36	14.29	37	15.98	27	14.42
	266	85.60	213	74.65	156	64.83
Exploratory:						
Oil	11	9.71	7	3.03	3	1.22
Gas	83	43.65	14	7.20	1	0.10
Non-productive	8	2.84	7	4.40	8	2.64

	102	56.20	28	14.63	12	3.96
Farmout or non-consent	5	-	10	-	8	-
Total (1)	373	141.80	251	89.28	176	68.79

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(1) Does not include seven, 15 and 14 gross wells completed on St. Mary's fee lands during 2004, 2003 and 2002, respectively, in which we have only a royalty interest.

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, 2004. 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	3,364	421	207	68	3,571	489
Colorado	2,845	2,206	24,712	13,357	27,557	15,563
Louisiana	132,153	40,675	23,105	8,841	155,258	49,516
Mississippi	2,588	262	4,049	2,077	6,637	2,339
Montana	53,549	33,879	452,638	300,103	506,187	333,982
New Mexico	6,280	2,694	1,320	1,187	7,600	3,881
North Dakota	131,362	86,441	160,753	98,504	292,115	184,945
Oklahoma	245,197	68,602	37,751	23,130	282,948	91,732
Texas	131,150	33,892	39,464	15,400	170,614	49,292
Utah (3)	480	115	13,712	5,866	14,192	5,981
Wyoming	73,993	45,036	422,231	252,694	496,224	297,730
Other (4)	2,761	903	4,144	1,169	6,905	2,072
	785,722	315,126	1,184,086	722,396	1,969,808	1,037,522
Louisiana Fee Properties	9,944	9,944	14,970	14,970	24,914	24,914
Louisiana Mineral Servitudes	9,745	5,306	4,571	4,208	14,316	9,514
	19,689	15,250	19,541	19,178	39,230	34,428
Total	805,411	330,376	1,203,627	741,574	2,009,038	1,071,950

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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) St. Mary holds an overriding royalty interest in an additional 40,100 gross acres in Utah.

(4) Includes interests in Alabama, Kansas, Nebraska, Nevada and South Dakota.

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 the date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a material adverse effect upon our financial condition or results of operations.

As previously reported, Nance Petroleum Corporation, a wholly owned subsidiary, is named along with several other leaseholders and interested parties as an additional co-defendant in a lawsuit that was originally filed in the U.S. District Court for the District of Montana on June 12, 2001. The plaintiff, the Northern Plains Resource Council, Inc.("NPRC"), an environmental public interest group, sued the U.S. Bureau of Land Management, the U.S. Secretary of the Interior, the Montana BLM State Director and Fidelity Exploration & Production Company. The lawsuit seeks the cancellation of all federal leases related to coalbed methane development in Montana issued by the BLM since January 1, 1997. This cancellation is sought primarily on the grounds of an alleged failure of the BLM to comply with federal environmental laws. NPRC alleges that the environmental impacts of coalbed methane development were not properly analyzed before the challenged leases were issued. The Montana portion of our Hanging Woman Basin coalbed methane project contains approximately 74,000 total net acres. The lawsuit potentially affects approximately 47,000 net acres that are subject to federal leases. Based on information presently available, we believe that the BLM complied with the applicable environmental laws, and the District Court agreed by granting the defendants' motion for summary judgment in December 2003. The court held that the issuance process regarding the federal leases in question complied with the applicable environmental laws. The plaintiff appealed this decision, and the Ninth Circuit Court of Appeals affirmed the decision of the trial court on August 26, 2004. Plaintiff has filed a petition for rehearing that was denied by the reviewing panel by its Order dated February 10, 2005. The only appeal left for the Plaintiffs is to petition for certiori to the U.S Supreme Court. Notwithstanding our success in the lower court and the appellate court, there is no assurance as to the ultimate outcome of the lawsuit, and therefore, there is no assurance that it will not adversely affect our coalbed methane project. Even if the federal leases in Montana become unavailable, we are proceeding with this project on non-federal leases in Wyoming, and we anticipate acquiring additional non-federal leases in Montana and Wyoming.

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

There were no matters submitted to a vote of our security holders during the fourth quarter of 2004.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

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

Name	Age	Position
Mark A. Hellerstein	52	Chairman of the Board, President and Chief Executive Officer
Douglas W. York	43	Executive Vice President and Chief Operating Officer
Robert L. Nance	68	Senior Vice President, and President and Chief Executive Officer of Nance Petroleum Corporation, a wholly-owned subsidiary of St. Mary
Jerry R. Schuyler	49	Senior Vice President and Regional Manager
Kevin E. Willson	48	Senior Vice President - Mid-Continent Drilling and Production
Robert T. Hanley	58	Vice President - Investor Relations and Management Reporting
David W. Honeyfield	38	Vice President - Finance, Treasurer and Secretary
Milam Randolph Pharo	52	Vice President - Land and Legal
Garry A. Wilkening	54	Vice President - Administration and Controller

Each executive officer has held his respective position during the past five years, except as follows:

Mark A. Hellerstein was appointed Chairman of the Board in September 2002.

Douglas W. York was appointed Executive Vice President and Chief Operating Officer in September 2003. Mr. York served as Vice-President - Acquisitions and Reservoir Engineering from 1996 to September 2003.

Robert L. Nance was appointed Senior Vice President in March 2001.

Jerry R. Schuyler joined St. Mary in December 2003 as Senior Vice President and Regional Manager of the Gulf Coast region. From November 2001 to July 2002, Mr. Schuyler was Senior Vice President and General Manager - Eastern Onshore Division for Dominion Exploration & Production, Inc., where he managed all operations and exploration for Dominion's Gulf Coast and eastern onshore U.S. regions. From March 2000 to November 2001, Mr. Schuyler was Senior Vice President and General Manager of Dominion's Onshore U.S. Division, where he managed all operations and exploration for all of Dominion's onshore U.S. regions. From 1996 to 2000, Mr. Schuyler was President and Managing Director, ARCO Middle East & Central Asia, where he managed all operations for ARCO International Oil & Gas Company in the Arabian Peninsula, Turkey and Pakistan.

Kevin E. Willson was appointed Senior Vice President and Regional Manager in November 2003. Mr. Willson served as Vice President - Mid-Continent Exploration/Production from October 1998 to November 2003. Mr. Willson joined Anderman/Smith, a predecessor to St. Mary's interests in the Mid-Continent region, in 1990 and was appointed Vice President - Mid-Continent Engineering for St. Mary in 1996.

Robert T. Hanley was appointed Vice President - Investor Relations and Management Reporting in April 2003. Mr. Hanley served as Vice President - Business Development from July 2000 to April 2003. Mr. Hanley was Chief Financial Officer of Nance Petroleum Corporation from 1999 to 2000 and Chief Financial Officer of Panterra Petroleum, a partnership between St. Mary and Nance Petroleum Corporation, from 1992 to 1999.

David W. Honeyfield joined St. Mary in May 2003 as Vice President - Finance, Treasurer and Secretary. Prior to joining St. Mary, Mr. Honeyfield was Controller and Chief Accounting Officer of Cimarex Energy Co. from September 2002 to May 2003 and Controller and Chief Accounting Officer of Key Production Company, Inc., which was acquired by Cimarex in September 2002. Prior to joining Key Production Company in April 2002, Mr. Honeyfield was a senior audit manager with Arthur Andersen LLP in Denver. Mr. Honeyfield had been with Arthur Andersen since January 1991.

Garry A. Wilkening was appointed Vice President - Administration in February 1999.

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 judgment the best interests of the Company will be served thereby without prejudice, subject however, to contractual rights, if any, of the person so removed. Mr. Hellerstein is chairman of the Board of Directors and has an employment agreement with St. Mary. The agreement is terminable at any time upon 30 days' notice by either party. Upon termination of the agreement by St. Mary for any reason other than death, disability or misconduct by Mr. Hellerstein, St. Mary is obligated to continue to pay his compensation and insurance benefits, at the level at the time of termination, for a period of one year.

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 EQUITYAND RELATED STOCKHOLDER MATTERS

Market Information. St. Mary's common stock is currently traded on the New York Stock Exchange under the symbol SM. The range of high and low sales prices for the quarterly periods in 2004 and 2003, as reported by the New York Stock Exchange, is set forth below:

Quarter Ended	High	Low
December 31, 2004	$ 43.00	$ 37.12
September 30, 2004	40.13	31.76
June 30, 2004	37.19	31.80
March 31, 2004	34.14	27.74
December 31, 2003	$ 29.19	$ 24.45
September 30, 2003	28.85	24.45
June 30, 2003	29.75	24.65
March 31, 2003	27.23	23.80

Holders. As of February 15, 2005, the number of record holders of St. Mary's common stock was 145. Management believes, after inquiry, that the number of beneficial owners of our common stock is in excess of 3,800.

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 2004. 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 credit facility, including the requirement that we maintain certain levels of stockholders' equity and the limitation of our annual dividend rate to no more than $0.20 per share. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $2.8 million in 2004 and $3.1 million in 2003.

Restricted Shares. Aside from Rule 144 restrictions on shares for insiders and restricted shares issued under the Employee Stock Purchase Plan and the Non-Employee Director Stock Compensation Plan, St. Mary has no restricted shares outstanding as of December 31, 2004.

Issuer Purchases of Equity Securities. St. Mary did not repurchase any shares of its common stock during the fourth quarter of 2004.

Equity Compensation Plans. St. Mary has a stock option plan, a restricted stock plan, an incentive stock option plan, an employee stock purchase plan, a non-employee director stock compensation plan under which options and shares of St. Mary common stock are authorized for grant or issuance as compensation to eligible employees, consultants and members of the Board of Directors. Our stockholders have approved each of these plans. See Note 7 - Compensation Plans in the Notes to Consolidated Financial Statements included in

Part IV, Item 15 of this report for further information about the material terms of these plans. The following table is a summary of the shares of common stock authorized for issuance under our equity compensation plans as of December 31, 2004:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under quity compensation plans (excluding securities ereflected in column (a))
Equity compensation plans approved by security holders	3,053,506	$ 22.32	1,471,349 (1)
Equity compensation plans not approved by security holders	-	-	-
Total	3,053,506	$ 22.32	1,471,349

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(1) Includes shares that are authorized for issuance under our employee stock purchase plan.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth supplemental selected financial and operating 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 consolidated financial statements included elsewhere in this report.

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands, except per share data)				
Total operating revenues	$ 433,099	$ 393,708	$ 196,305	$ 207,469	$ 195,666
Income before cumulative effect of change in accounting principle	$ 92,479	$ 90,140	$ 27,560	$ 40,459	$ 55,620
Net income per share:					
Basic	$ 3.21	$ 3.06	$ 0.99	$ 1.45	$ 2.00
Diluted	$ 2.88	$ 2.80	$ 0.97	$ 1.42	$ 1.97
Total Assets	$ 945,460	$ 735,854	$ 537,139	$ 436,989	$ 321,895
Long-term obligations:					
Line of credit	$ 37,000	$ 11,000	$ 14,000	$ 64,000	$ 22,000
Convertible Notes	$ 99,791	$ 99,696	$ 99,601	-	-
Cash dividends declared per common share	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10

Supplemental Selected Financial and Operational Data:

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands, except per volume data)				
Balance Sheet Data:					
Total working capital	$ 12,035	$ 3,101	$ 2,050	$ 34,000	$ 40,639
Total stockholders' equity	$ 484,455	$ 390,653	$ 299,513	$ 286,117	$ 250,136
Weighted-average shares outstanding:					
Basic	28,851	31,233	27,856	27,973	27,781
Diluted	33,447	35,534	28,391	28,555	28,271
Reserves:					
Gas (Mcf)	319,196	307,024	274,172	241,231	225,975
Oil (Bbls)	56,574	47,787	36,119	23,669	20,950
MCFE	658,638	593,744	490,887	383,247	351,673
Production and Operational: Data:					
Oil and gas production revenues,					

including hedging	$ 413,318	$ 365,114	$ 185,670	$ 203,973	$ 188,407
LOE and production taxes	$ 95,518	$ 88,509	$ 50,839	$ 55,000	$ 38,461
DD&A	$ 92,223	$ 81,960	$ 54,432	$ 51,346	$ 40,129
General and administrative	$ 22,004	$ 21,197	$ 13,683	$ 11,762	$ 11,166
Production Volumes:					
Gas (Mcf)	46,598	49,663	38,164	39,491	38,346
Oil (Bbls)	4,799	4,541	2,815	2,434	2,398
MCFE	75,393	76,909	55,055	54,093	52,731
Realized Price - pre hedging:					
Per BBl	$ 39.77	$ 29.40	$ 24.67	$ 24.08	$ 29.02
Per Mcf	$ 5.85	$ 5.12	$ 3.10	$ 4.22	$ 3.98
Realized Price - net of hedging:					
Per Bbls	$ 32.53	$ 26.96	$ 25.34	$ 23.29	$ 23.53
Per Mcf	$ 5.52	$ 4.89	$ 3.00	$ 3.73	$ 3.44
Expense per MCFE Data:					
LOE and production taxes	$ 1.27	$ 1.15	$ 0.92	$ 1.02	$ 0.73
DD&A	$ 1.22	$ 1.07	$ 0.99	$ 0.95	$ 0.76
General and Administrative	$ 0.29	$ 0.28	$ 0.25	$ 0.22	$ 0.21
Cash Flow Data:					
From operations	$ 237,162	$ 204,319	$ 141,709	$ 127,492	$ 92,267
For investing	$ (247,006)	$ (196,939)	$ (180,931)	$ (159,075)	$ (112,868)
From (for) financing	$ 1,435	$ (3,707)	$ 46,260	$ 29,080	$ 13,025

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

This discussion includes forward-looking statements. Please refer to the Cautionary Statement about Forward-Looking Statements section in Part I, Item 1 of this document for an explanation of these types of statements.

Overview of the Company

General Overview

We are an independent energy company focused on the exploration, exploitation, acquisition and production of natural gas and crude oil in the United States. We earn our revenues and generate our cash flows from operations primarily from the sale of produced natural gas and crude oil. Our oil and gas reserves and operations are concentrated primarily in the Anadarko, Arkoma, Permian and various Rocky Mountain basins and the onshore Gulf Coast and offshore Gulf of Mexico. We maintain a balanced portfolio of proved reserves, development drilling opportunities and non-conventional gas prospects. As of December 31, 2004, we had estimated proved reserves of 659 BCFE, with a before income tax PV-10 value of $1.5 billion and an after income tax value of $1.0 billion. Our reserves are 85 percent proved developed and 52 percent oil.

Oil and Gas Prices

Our results of operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. In 2004 oil and gas producers benefited from high oil and gas commodity prices. Increased prices of natural gas are the result of tightening supply coupled with increasing demand in the United States. Because of finite storage capacity, changes in domestic demand created by weather have a significant effect on price volatility. Increases in oil price are more a result of global events than events in the United States. These include a decrease in excess worldwide production capacity, a continuing increase in demand from the global economy, and continued instability in the Middle East.

Reserve Replacement and Growth

Like all oil and gas exploration and production companies, we face the challenge of natural resource production decline. An oil and gas exploration and production company depletes part of its asset base with each unit of oil and gas it produces. Historically we have been able to grow our production despite this natural decline by adding more reserves through acquisitions and drilling than we produce. Future growth will depend on our ability to continue to add reserves in excess of production.

We believe that growth in net asset value per share drives appreciation in our stock price. Our challenge to grow net asset value per share has always been a difficult one. To do this we set a goal of economically replacing 200 percent of our annual production and growing production by 15 percent per year. Please see our additional discussion of oil and gas reserve quantities in our critical accounting policies and estimates section. In 2004 we replaced 190 percent of our reserves at a finding cost of $2.19 per MCFE. We believe the increase in finding costs from the $1.05 amount we reported for the year ended December 31, 2003, is generally reflective of increasing costs industry-wide together with 2003 being an excellent year for St. Mary. Finding cost and reserve replacement percentage are defined in the glossary at the end of Part I Item 1 of this report. They are comparison measures used to evaluate the effectiveness of an oil and gas company's reserve replacement program and a snapshot in time of its future profitability. You should note that aberrations, causing both good and bad results, will occur over short intervals of time.

Sustainability in our business is dependent on the ability to create new ideas and new value year after year. The challenges we face are becoming increasingly difficult as North American oil and gas production continues to decline and other exploration and production companies compete for available reserves. We believe we have a formula for meeting these challenges. We have placed talented geoscientists, engineers and landmen in each of our regional offices where their local knowledge and experience can be fully utilized. They are supported with a strong balance sheet and fiscal and operating discipline.

In 2004 our pre-tax PV-10 value for proved reserves increased 17 percent to $1.5 billion, with a standardized measure value of $1.0 billion. These amounts reflect an 11 percent increase in reserves, a 29 percent increase in adjusted oil reserve pricing to $40.06 per barrel, and a two percent increase in adjusted gas reserve pricing to $5.80 per Mcf.

2004 Highlights

In 2004 we experienced continuing high oil and gas prices, a modest decrease in production and earnings, an 11 percent increase in proved reserves obtained at an acceptable reserve replacement cost, moderate increases in operating costs, profitable sales of non-strategic assets, and advancement of the Hanging Woman Basin coalbed methane project to the production stage with evaluated proved reserves. Highlights for 2004 also include good drilling results at the horizontal Middle Bakken play and in the Red River formation in the Williston Basin; the repurchase of approximately 3.4 million shares of our common stock from Flying J at a price of $26.92 per share; the repurchase of an additional 489,300 shares of our common stock under our stock repurchase program at an average price of $33.39 per share, and we closed on $76.7 million of oil and gas property acquisitions for a total of $68.8 million in cash. Our cash outflows were funded by existing cash and short-term investments on hand, from operating cash flows and from funds available under our existing credit facility. From December 2003 to December 2004 the outstanding balance on our credit facility increased by $26.0 million.

In 2004 oil prices soared to record levels as excess OPEC capacity shrank to an estimated one percent to two percent of total demand. Demand for oil was impacted by the growing economies of China and India as well as from a recovering U.S. economy. Spot market prices reflected worldwide concerns about producer ability to ensure sufficient supply to meet increasing demand amid a host of uncertainties caused by weather-related destruction, political instability, a weaker US dollar, oil rig workers strikes and crude oil refining constraints. Average natural gas prices for the year were at an all-time high due to supply and transportation constraints, weather-related lost production, and continuing strong demand for natural gas in domestic markets resulting from an improving economy and the effect of high oil prices on natural gas demand. NYMEX prices for the year averaged $6.09 per MMBtu and $41.40 per barrel, translating into a 15 percent increase to our per MCFE realized price. At December 31, 2004, the 12-month NYMEX strip was $42.59 per barrel for oil and $6.27 per MMBtu for gas.

Net income for 2004 was $92.5 million or $2.88 per diluted share compared to $95.6 million or $2.80 per diluted share for the prior year. Net cash provided by operating activities was $237.2 million, up 16 percent from 2003. Production decreased two percent to 75.4 BCFE. Our average realized price increased 15 percent to $5.48 per MCFE. Unit costs increased modestly for the period as production expenses increased $0.12 to $1.27 per MCFE, DD&A with impairments increased $0.15 to $1.22 per MCFE and adjusted general and administrative expense increased $0.01 to $0.29 per MCFE from $0.28 per MCFE in 2003. The $0.28 per MCFE general and administrative amount for 2003 has been

adjusted to reflect the separate presentation of the change in net profits plan liability expense as discussed in detail below in our comparison of financial results and trends between 2004 and 2003. Other analyses throughout this report also reflect changes to exploration expense and general and administrative expenses for this item.

The future outlook for oil and gas prices to remain high is very positive, and the worldwide economy appears to be recovering. We have attractive prospects to drill. Rig counts are growing, and we have seen the impact of escalating rig and other service costs. The country's ability to supply gas remains challenged as the average decline rate for natural gas has increased from 16 percent to 30 percent over the past thirteen years. This change is a result of increased activity in the Gulf of Mexico where reserve lives are very short, the use of 3D seismic to identify smaller reservoirs, the use of better completion techniques that allow reserves to be produced faster, and more efficient high deliverability storage that allows wells to be produced at full capacity all year long. New sources of gas such as LNG, frontier regions (e.g. deepwater Gulf of Mexico and Mackenzie Delta, Alaska) and unconventional gas plays are all more costly and have long lead times, but at some point could have a positive impact on supply. We believe oil prices are high now due to perceptions of reduced spare capacity, increasing worldwide demand and an apparent increased target price range for OPEC due to a decline in the value of the dollar.

We enter 2005 in good financial condition and with a capital expenditure budget of $418 million. In an environment with a competitive acquisition market and increasing drilling and service costs, we plan to add value in 2005 as follows:

- Of the $418 million capital expenditures budget, 30 percent is allocated for acquisitions. The remaining 70 percent available for exploration and development is allocated 23 percent for conventional projects and 6 percent for coalbed methane projects in the Rocky Mountain region, 21 percent in the Mid-Continent region, 10 percent in the Gulf Coast region, 8 percent in the ArkLaTex region, and 2 percent in the Permian region. The 2005 exploration and development budget is $293 million, which represents a 28 percent increase over 2004 exploration and development expenditures.

- Our Hanging Woman Basin coalbed methane project will move into full development with the drilling of approximately 150 wells in Wyoming and the production of more meaningful volumes from wells drilled last year. Our strong balance sheet would allow us to pursue other potentially large unconventional opportunities.

- On January 5, 2005, the Company closed the acquisition of Agate Petroleum Inc. for $39.6 million in cash. The estimated preliminary purchase accounting results in the recording of approximately $42.1 million to oil and gas properties, $3.0 million to working capital, $9.4 million to goodwill, deferred income tax liability of $13.6 million and a $1.3 million asset retirement obligation. The goodwill and deferred income tax liability are a result of acquiring assets with tax basis that is lower than book basis. Accounting rules are inconsistent with the economic evaluation criteria we applied in determining the bid amount for this transaction because present value considerations cannot be applied to the amounts recorded for deferred income taxes.

- We anticipate that acquisitions and our drilling programs will result in increased production.

A year-to-year overview of selected reserve, production and financial information, including trends:

	As of and for the Years Ended			% of Change Between	
	2004	2003	2002	2004/2003	2003/2002
Selected Operations Data (In Thousands, Except Price and Per MCFE Amounts):					
Total proved reserves (PV-10 basis)					
Natural gas (Mcf)	319,196	307,024	274,172		
Oil (Bbl)	56,574	47,787	36,119		
MCFE	658,638	593,744	490,887	11%	21%
Net production volumes					
Natural gas (Mcf)	46,598	49,663	38,164		
Oil (Bbl)	4,799	4,541	2,815		
MCFE	75,393	76,909	55,055	(2)%	40%
MCFE per day	206	211	151	(2)%	40%
Average daily production					
Natural gas (Mcf)	127	136	105		
Oil (Bbl)	13	12	8		
MCFE	206	211	151	(2)%	40%
Oil & gas production revenues					
Gas production, including hedging	$ 257,206	$ 242,670	$ 114,334		
Oil production, including hedging	156,112	122,444	71,336		
Total	$ 413,318	$ 365,114	$ 185,670	13%	97%
Oil & gas production costs					
Lease operating expenses	$ 61,269	$ 59,152	$ 36,472		
Transportation costs	7,235	7,197	3,184		
Production taxes	27,014	22,160	11,183		
Total	$ 95,518	$ 88,509	$ 50,839	8%	74%
Average realized sales price (1)					
Natural gas (per Mcf)	$ 5.52	$ 4.89	$ 3.00	13%	63%

Oil (per Bbl)	$ 32.53	$ 26.96	$ 25.34	21%	6%
Per MCFE data:					
Average net realized price (1)	$ 5.48	$ 4.75	$ 3.37	15%	41%
Lease operating expense	(0.81)	(0.77)	(0.66)	5%	17%
Transportation costs	(0.10)	(0.09)	(0.06)	11%	50%
Production taxes	(0.36)	(0.29)	(0.20)	24%	45%
General and administrative	(0.29)	(0.28)	(0.25)	4%	27%
Operating profit	$ 3.92	$ 3.32	$ 2.20	18%	49%
Depletion, depreciation and amortization	$ 1.22	$ 1.07	$ 0.99	15%	8%
Financial Information (In Thousands, Except Per Share Amounts):					
Working capital	$ 12,035	$ 3,101	$ 2,050	358%	51%
Long-term debt	$ 136,791	$ 110,696	$ 113,601	24%	(3)%
Stockholders' equity	$ 484,455	$ 390,653	$ 299,513	26%	30%
Net income	$ 92,479	$ 95,575	$ 27,560	(3)%	247%
Basic net income per common share	$ 3.21	$ 3.06	$ 0.99	5%	209%
Diluted net income per common share	$ 2.88	$ 2.80	$ 0.97	3%	189%
Basic weighted-average shares outstanding	28,851	31,233	27,856	(8)%	12%
Diluted weighted-average shares outstanding	33,447	35,534	28,391	(6)%	25%
Net cash provided by operating activities	$ 237,162	$ 204,319	$ 141,709	16%	44%
Net cash used in investing activities	$ (247,006)	$ (196,939)	$(180,931)	25%	9%
Net cash provided by (used in) financing activities	$ 1,435	$ (3,707)	$ 46,260	139%	(108)%

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(1) Includes the effects of our hedging activities.

We present this table as a summary of information relating to those key indicators of financial condition and operating performance that we believe to be important.

The increase in our reserve volumes reflects our drilling results and acquisition activity combined with increases in natural gas and crude oil prices used to evaluate reserves. Please see Note 12 of Part IV, Item 15 for additional details. Over time these will be the factors that determine if we are successful in achieving our target of replacing 200 percent of our production each year. We anticipate that we must continue our successful drilling program and average one or more relatively significant acquisitions per year in the current price environment to achieve this level of growth. The measure of our success will vary from year-to-year due to changes in these factors, some of which we can control and others which we cannot control. From January 1, 2002, to December 31, 2004, we replaced 259 percent of our production at a finding cost of $1.38 per MCFE.

The changes in production volumes, oil and gas production revenues and costs reflect the cyclical and highly volatile nature of prices our industry receives for production and the effect of the timing of acquisitions. Actual results in 2002 reflected a lower price environment than in either 2003 or 2004. We closed our acquisition of the Burlington Resources properties in late 2002 and our acquisition of the Flying J properties in early 2003. Production of 13.8 MMCFE from these two acquisitions was realized in 2003. These were the two largest acquisitions in our history and, combined with our successful drilling results in 2002 and 2003, resulted in a 40 percent increase in production from 2002 to 2003. The comparison of changes in production from 2003 to 2004 reflects the mix of results from our drilling programs in 2004 and the timing of our acquisitions made in the fourth quarter of 2004.

We present per MCFE information since we use this information to evaluate our performance relative to our peers and to measure trends that we believe require analysis. Our year-to-year comparison of financial results presented later provides additional details for the changes between years. We expect oil and gas production expenses will increase in 2005 as a result of increased activity in our higher-cost Rocky Mountain region, increased production taxes, and general inflation due to higher oil and gas pricing. Depreciation, depletion and amortization will continue to increase due to the higher costs associated with finding and acquiring crude oil and natural gas reserves. General and administrative expense is also projected to increase for expense associated with our net profits plan, expensing of stock-based compensation and costs we incur to comply with the Sarbanes-Oxley Act of 2002.

We had a modest decrease in net income from 2003 to 2004. However, if we compare net income before the cumulative effect of change in accounting principle recorded in 2003, we had a net income increase driven by realized price increases of 13 percent for natural gas and 21 percent for oil. By containing our costs, our operating profit as a percentage of net realized price was 71 percent in 2004 compared to 70 percent in 2003 and 65 percent in 2002. Net income as a percentage of oil and gas revenue net of hedging loss was 22 percent in 2004, 25 percent in 2003 and 15 percent in 2002.

We have in-the-money stock options, unvested restricted stock units and convertible notes that are considered dilutive securities. At times these dilutive securities can affect our earnings per share, and both basic and diluted earnings per share are presented in the table above. You should review Note 1 of Part IV, Item 15 of this report for a detailed explanation. Our basic and diluted weighted-average common shares outstanding used in our 2004 earnings per share calculations reflects a decrease in shares caused by our repurchase of our common stock from Flying J and the re-initiation of our stock repurchase program offset by an increase in outstanding shares related to stock options.

The remaining information in the table relates to information we have provided in operations update press releases and is intended to supplement the discussion above.

Overview of Liquidity and Capital Resources

We own depleting assets. In order to maintain our current size and to sustain our projected growth levels, we will have to successfully invest capital into new projects and acquisitions. The following analysis and discussion includes our assessments of market risk and possible effects of inflation and changing prices.

Sources of cash

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 the general condition of our industry and significant fluctuations in oil and gas prices, operating costs and volumes produced. We have virtually no control over the market prices for oil and gas. A decrease in these market prices would reduce expected cash flow from operating activities, might reduce the borrowing base on our credit facility, could reduce the value of non-strategic properties we might consider selling and historically has limited our industry's access to the capital markets.

Our current credit facility. On January 29, 2003, we entered into a $300.0 million credit facility with Wachovia Bank as Administrative Agent and eight other participating banks. This credit facility has a maturity date of January 27, 2006. We anticipate renegotiating the terms of our facility in the first quarter of 2005 to ensure that we have a credit facility in place beyond the date of current expiration. The calculated borrowing base as of December 31, 2004, is $325.0 million. We have elected a commitment amount of $150.0 million under this facility, which results in lower commitment fees payable to the bank syndicate. We believe this commitment level is adequate for our near-term liquidity requirements. Under our existing credit facility, our next borrowing base redetermination is scheduled to occur by the end of April 2005. You should note the possibility that the banks may not agree to a borrowing base redetermination that is adequate for our planned financing requirements. We must comply with certain financial and non-financial covenants, and we are currently in compliance with all of these covenants. Interest and commitment fees are accrued based on the borrowing base utilization percentage. LIBOR based borrowings accrue interest at LIBOR plus the applicable margin from the utilization table located in Note 5 of Part IV, Item 15 of this report, and Alternate Base Rate borrowings accrue interest at prime plus the applicable margin from the utilization table. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations. Our loan balance of $37.0 million on December 31, 2004, was comprised of $10.0 million in ABR borrowings and $27.0 million in LIBOR based loans.

Our weighted-average interest rate paid in 2004 was 7.1 percent and included commitment fees paid on the unused portion of the credit facility borrowing base, amortization of deferred financing costs, and amortization of the contingent interest embedded derivative associated with the convertible notes.

Interest Rate Market 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 discussed below presents the hypothetical change in fair value of those financial instruments we held at December 31, 2004, 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, interest rate changes for floating-rate debt 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. After consideration of the effect of interest rate swaps discussed below, we had floating-rate debt of $87 million and fixed-rate debt of $50 million at December 31, 2004. 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 $870,000 before taxes. The results of operations impact might be less than this amount as a direct effect of the capitalization of interest for wells drilled in the next year. 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.

Uses of cash

We use cash for the acquisition, exploration and development of oil and gas properties and for the payment of debt obligations, trade payables and stockholder dividends. Exploration and development programs are generally financed from internally generated cash flow, debt financing and cash and cash equivalents on hand. Cash used for the acquisition of oil and gas properties and the payment of stockholder dividends is discretionary and can be reduced or eliminated in the event of an unexpected decrease in oil and gas prices. 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. Over the next year we are required to only make interest payments on our debt obligations. An unexpected increase in oil and gas prices would provide flexibility to modify our uses of cash flow.

Over the course of 2004 we increased our outstanding debt by a net $26.0 million. Using this amount, cash on hand and cash flows from operations we paid $68.8 million for property acquisitions, spent $199.4 million on capital development and used $35.7 million to repurchase our common stock. We also made $14.8 million of cash payments for income taxes and $2.8 million for dividends. At February 15, 2005, we had $46.0 million outstanding on our credit facility.

On February 9, 2004, we repurchased for $91.0 million the 3,380,818 restricted shares of common stock that we issued to Flying J on January 29, 2003. Flying J used the proceeds to repay their outstanding loan principal balance to us of $71.6 million. Accrued interest on the loan, which was not recorded by us for financial reporting purposes due to the non-recourse nature of the loan, was forgiven. The $19.4 million net cash outlay was funded from our existing cash balance and borrowings under our credit facility. See Note 3 of Part IV, Item 15 of this report.

We re-initiated our stock repurchase program in August 2004. Since that time we have repurchased a total of 489,300 shares of our common stock for $16.3 million. As of February 15, 2005, there were 2,510,700 shares authorized to be repurchased under the program.

The following table presents amounts and percentage changes between years in net cash flows from our operating, investing and financing activities. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part IV, Item 15 of this report.

	Amount of Change Between		Percent of Change Between	
	2004/2003	2003/2002	2004/2003	2003/2002
Net Cash Provided By Operating Activities	$ 32,843	$ 62,610	16%	44%
Net Cash Used In Investing Activities	$ (50,067)	$ (16,008)	25%	9%
Net Cash Provided By (Used In) Financial Activities	$ 5,142	$ (49,967)	(139)%	(108)%

Analysis of cash flow changes between 2004 and 2003

Operating activities. Sources of cash flow from oil and gas sales increased $40.7 million from the period ended December 31, 2003 to the period ended December 31, 2004. This was a result of a 15 percent increase in our realized prices that offset a net production decrease between the comparative periods. Cash expenditures for operating expenses, exploration expense and administrative expenses increased by $2.4 million. Other revenue items decreased by $5.7 million.

Investing Activities. The increase in net cash used resulted from $75.6 million of increased drilling expenditures in 2004 over 2003 and from a 2004 cash payment of $3.8 million held as a deposit for our Agate acquisition. These increases were offset by a $7.6 million decrease in acquisition activity in 2004. Total capital expenditures increased by 34 percent to $268.2 million from $200.2 million in 2003. Proceeds from sales of oil and gas properties decreased by $20.7 million, but expiration of the restriction period for funds held for deferred tax exchange of oil and gas properties and net receipts from short-term investments resulted in a net cash provided change between periods of $41.8 million. Volumes, revenue and net operating margin from properties that were sold in 2003 and 2004 were not a material component in the consolidated statements of operations or balance sheets for any year presented, nor do they represent a group of assets that would qualify for discontinued operations accounting treatment.

Cash expended in 2003 for acquisitions of oil and gas properties included our utilization of $71.6 million of short-term investments, cash equivalents and increased borrowings under our credit facility to provide a loan to Flying J as part of our acquisition of properties. This loan was secured by the shares of our common stock issued in the transaction.

Financing activities. The $5.1 million increase in cash provided by financing activities reflects the $26.0 million we borrowed on our credit facility in 2004 to fund acquisitions and drilling activity and an $11.5 million increase in proceeds from stock option exercises over the 2003 amounts. We paid $19.4 million to repurchase our shares from Flying J on February 9, 2004, and we paid $16.3 million to repurchase shares under our stock repurchase program. In 2003 we borrowed to fund our acquisition of properties from Flying J and used cash flow from operations to reduce our outstanding debt for the year.

St. Mary had $6.4 million in cash and cash equivalents and had working capital of $12.0 million as of December 31, 2004, compared to $14.8 million in cash and cash equivalents and working capital of $3.1 million as of December 31, 2003.

Analysis of cash flow changes between 2003 and 2002

Operating activities. The differences above reflect increases in sources of cash flow from oil and gas sales due to a 40 percent increase in production and a 41 percent increase in price. We did not see the full $99.2 million benefit of the net change between years in our cash flow since $40.8 million of the change in net income, adjusted for non-cash items, related to a 2003 increase in outstanding accounts receivable of $29.7 million and an $11.1 million decrease in outstanding accounts receivable in 2002. The remaining $5.7 million difference relates to proceeds from asset sales, collections of refundable income tax and increases in prepaid expenses and accounts payable.

Investing Activities. The increase results primarily from additional capital and exploration costs. Total 2003 capital expenditures for cash, including acquisitions of oil and gas properties, increased $15.5 million or 8 percent to $200.2 million in 2003 compared to $184.7 million in 2002. Increases in proceeds from sales were partially offset by amounts deposited in long-term restricted cash accounts for the tax-deferred exchange of oil and gas properties. The long-term restricted cash was available to be used for the

acquisition of oil and gas properties in 2004. The amount of cash invested in long-term restricted cash reflects our projection of the likelihood we will be successful. Our sales of proved oil and gas properties in 2003 resulted in $23.5 million of cash proceeds. Revenue and net operating margin from the properties that we sold were not a material component of the current year or any prior year component of the consolidated statements of operations or balance sheets, nor do they represent a group of assets that would qualify for discontinued operations accounting treatment.

Cash expended in 2003 for acquisitions of oil and gas properties includes our utilization of $71.6 million of short-term investments, cash equivalents and increased borrowings under our credit facility to provide a loan to Flying J as part of our acquisition of properties. This loan was secured by the shares of our common stock issued in the transaction.

In December 2002 we purchased oil and gas properties from Burlington Resources Oil & Gas Company LP for $69.5 million in cash. We financed this acquisition using cash on hand and a portion of our credit facility.

Financing activities. The $50.0 million decrease from 2002 to 2003 reflects the issuance of our convertible notes and a $3.0 million pay down of our credit facility in 2003.

In March 2002, we issued a total of $100.0 million of our convertible notes with a 0.5 percent contingent interest provision in a private placement. Interest payments are due on March 15 and September 15 of every year. We received net proceeds of $96.8 million after deducting the initial purchasers' discount and offering expenses payable by us. The convertible 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. We used a portion of the net proceeds from the convertible notes to repay our credit facility balance and used the remaining net proceeds to fund a portion of our 2002 capital expenditures. In October 2004 we entered into interest rate swap agreements on a total notional amount of $50.0 million of the convertible notes, which lowered our interest expense in 2004. The convertible notes can be converted into our common stock at a conversion price of $26.00 per share, subject to adjustment. See Note 5 of Part IV, Item 15 of this report for a more detailed discussion of the conversion features. The first date that St. Mary may redeem the convertible notes is in March 2007. Our current stock price is in excess of the $26.00 conversion price.

St. Mary had $14.8 million in cash and cash equivalents and had working capital of $3.1 million as of December 31, 2003, compared to $11.2 million in cash and cash equivalents and working capital of $2.1 million as of December 31, 2002.

2005 Capital Expenditure Budget

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, add additional geoscientists and/or engineers, or gain a significant acreage and production foothold in a new basin.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We anticipate spending approximately $418 million for capital and exploration expenditures in 2005 with $125 million allocated for acquisitions of producing properties. Anticipated ongoing exploration and development expenditures for each of our core areas are as follows:

	In Millions	Gross Well Count
Rocky Mountain region	$ 95	118
Mid Continent region	87	90
Gulf Coast region	41	27
ArkLaTex region	34	81
Coalbed Methane	26	183
Permian Basin region	10	35
Total	$ 293	534

We regularly review our capital expenditure budget to reflect changes in current and projected cash flows, acquisition opportunities, debt requirements and other factors. The above allocations are subject to change based on various factors and results, including the availability of drilling and service rigs.

The following table sets forth certain information regarding the costs incurred by us in our oil and gas activities:

	Years Ended December 31,		
	2004	2003	2002
		(In thousands)	
Development costs	$ 190,829	$ 111,908	$ 74,376
Exploration costs	37,977	33,296	22,548
Acquisitions:			
Proved	69,054	73,989	85,559
Unproved	7,646	8,942	2,147
Leasing activity	7,877	7,480	8,128
Total	$ 313,383	$ 235,615	$ 192,758

Our costs incurred for capital and exploration activities in 2004 increased $77.8 million or 33 percent compared to 2003. This increase was a result of a planned $20.3 million increase in the drilling activity budget, a $17.1 million increase in the acquisition budget, an $8.6 million increase in capitalized costs associated with asset retirement obligations, and an additional $63.0 million spent on opportunities that arose during 2004. We reallocated $31.2 million from the acquisitions budget for these opportunities.

We continue to move forward with the development of coalbed methane reserves in our Hanging Woman Basin project. We have 154,000 net lease acres in the basin and are concentrating our initial development on 80,000 net acres located in Wyoming. Outstanding legal challenges filed by environmental public interest groups affect 47,000 net acres in Montana relating to this project. See Legal Proceedings under Part I, Item 3 of this report.

In 2002 we used a portion of the proceeds from our convertible debt offering to fund our capital expenditures budget, but historically we have used internally generated cash flow, existing cash and our credit facility. We believe that internally generated cash flow and our credit facility will be utilized in 2005. 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, whether we can make economic acquisitions and our ability to assimilate acquisitions we are considering. 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.

Financing alternatives

The debt and equity financing capital markets remain very attractive to energy companies who operate in the exploration and production segment. This is a result of strong commodity prices and the general strength reflected in the balance sheets of the companies in this segment. As our cash balance and availability under our existing credit facility are significant, we are not currently considering accessing the capital markets in 2005. However, if additional development or attractive acquisition opportunities arise that exceed our current available resources, we may consider other forms of financing, including the public offering or private placement of equity or debt securities as well as expanding our borrowing availability under traditional secured bank financing.

Sensitivity analysis

The next table reflects our estimate of the effect on cash flow from operations for the years presented of a 10 percent change in our average realized sales price for natural gas, for oil and in total. These amounts have been reduced by the effective income tax rate applicable to each period since a reduction in revenue would reduce cash requirements to pay income taxes. General and administrative expenses have not been adjusted. To fund the capital and exploration expenditures we incurred in those years we would have been required to access our credit facility as a source of funds. In each of these years we had sufficient borrowing base available under our credit facility to meet this contingency without reducing or eliminating expenditures and affecting our growth strategy. Taking into account the February 15, 2005, loan balance of our credit facility we believe we have sufficient borrowing base available to continue our growth strategy if prices should change.

Pro Forma effect on revenues of a 10 percent change in average sales price:	As of and for the Years Ended December 31,		
	2004	2003	2002
		(In thousands)	
Natural Gas	$ 15,280	$ 13,889	$ 6,944
Oil	$ 9,180	$ 6,979	$ 4,350
Total	$ 24,460	$ 20,868	$ 11,294

Summary of oil and gas production hedges in place

Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted transactions. We have historically entered into hedges of existing production around the time we make acquisitions of producing oil and gas properties. Our intent is to lock-in a significant portion of an equivalent amount of our existing production to the prices we used to evaluate the economics of our acquisition. We are also hedging a small percentage of our forecasted production on a discretionary basis.

Note 10 of Part IV, Item 15 of this report contains important information about our oil and gas derivative contracts including the volumes and average contract prices of hedges we currently have in place as of December 31, 2004. We have not entered into any additional hedges as of February 15, 2005. We anticipate that all hedge transactions will occur as expected.

For swap contracts in place on December 31, 2004, a hypothetical increase of 10 percent in future gas strip prices representing a $0.58 weighted-average increase per MMBtu applied to a notional amount of 9.9 million MMBtu covered by natural gas swaps would cause a decrease in the value of derivative instruments of $5.7 million. A hypothetical increase of 10 percent in the future NYMEX strip oil prices representing a $4.12 increase per Bbl applied to a notional amount of 1.4 MMBbl covered by crude oil swaps would cause a decrease in the value of derivative instruments of $5.7 million.

For collar contracts in place on December 31, 2004, a hypothetical increase of 10 percent in future gas strip prices representing a $0.57 weighted-average increase per MMBtu applied to a notional amount of 1.9 million MMBtu covered by natural gas collars would cause a decrease in the value of derivative instruments of $729,000.

The effect of price increases would impact our hedge gain or loss amounts. However, these are cash flow hedges with high correlation, and the price we receive on the underlying production would be higher by approximately the same amount. The effect on our results of operations would be minimal.

Summary of interest rate hedges in place

We entered into fixed-rate to floating-rate interest rate swaps on $50.0 million of convertible notes on October 3, 2003. We attempt to maintain a balanced allocation between fixed and floating rate debt. As our usage of the credit facility at that time was nearing zero, we elected to exchange fixed rate payments for floating rate payments on a portion of the interest on our convertible notes. This hedge does not qualify for fair value hedge treatment under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. Excluding accrued payments due to us at December 31, 2004, the interest rate swaps had a fair value liability of $432,000. Derivative loss in the consolidated statements of operations for the years ended December 31, 2004, and 2003, includes $328,000 and $104,000, respectively, of loss related to the fair value liability increase.

Schedule of contractual obligations

The following table summarizes our future estimated principal payments and minimum lease payments for the periods specified (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 137.0	$ -	$ 137.0	$ -	$ -
Operating Leases	10.7	2.4	3.1	2.3	2.9
Other Long-Term Liabilities	10.6	1.8	4.7	1.7	2.4
Total	$ 158.3	$ 4.2	$ 144.8	$ 4.0	$ 5.3

This table excludes the unfunded portion of our estimated pension liability of $1.4 million, as we cannot determine with accuracy the timing of future payments. The table also excludes estimated payments associated with our

net profits plan. We record a liability for the estimated future payments. However, predicting the precise timing the liability will be paid is contingent upon estimates of appropriate discount factors adjusting for risk and time-value and upon a number of factors that we cannot control. We have excluded asset retirement obligations because we are not able to precisely predict the timing for these amounts. Pension liabilities and asset retirement obligations are discussed in Note 8 and Note 9, respectively, and the net profits plan is discussed in Note 7 of Part IV, Item 15 of this report.

Three leases for office space will expire in year 3, and a fourth office space lease will expire in year 4. Estimated costs to replace these leases are not included in the table above. For purposes of the table we assume that the holders of our convertible notes will not exercise the conversion feature. If the holders do exercise their conversion feature, we will not have to repay the $100.0 million upon conversion. Our common shares outstanding would increase by 3,846,150 shares.

We believe that we will continue to pay annual dividends of at least $0.10 per share. We anticipate making cash payments for income taxes, dependent on net income and capital spending.

Off-Balance Sheet Arrangements

Aside from operating leases we do not have any off-balance sheet financing nor do we have any unconsolidated subsidiaries.

Critical Accounting Policies and Estimates

We are engaged in the exploration, development, acquisition and production of natural gas and crude oil. Our discussion of financial condition and results of operation is based upon the information reported in our consolidated financial statements. The preparation of these consolidated 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 affecting the estimates we use on historical experience and various other sources that are believed to be reasonable under the circumstances. Actual results may differ from the estimates we calculate 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 - Summary of Significant Accounting Policies, Note 9 - Asset Retirement Obligations, and Note 12 - Disclosures About Oil and Gas Producing Activities in Part IV, Item 15 of this report.

Oil and gas reserve quantities. Estimated reserve quantities and the related estimates of future net cash flows are the most important estimates for an exploration and production company because they affect the perceived value of our company, are used in comparative financial analysis ratios, and are used in significant accounting estimates including the 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 periods 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, quality 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 purpose for which the reserve estimates will be used. For example, the standardized measure calculation required by SFAS No. 69, Disclosures about Oil and Gas Producing

Activities, requires a 10 percent discount to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established proved producing oil and gas properties, we make considerable effort to estimate our reserves. We expect that periodic reserve estimates will change in the future as additional information becomes available or as oil and gas prices and operating and capital costs change. We evaluate and estimate our oil and gas reserves at December 31 and June 30 of each year. For purposes of depletion, depreciation, and impairment, reserve quantities are adjusted at all interim periods for the estimated impact of additions and dispositions. Changes in depletion, depreciation or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period that the reserve estimates changed.

The following table presents information regarding reserve changes from period to period that reflect changes from items we do not control, such as price, and from changes resulting from better information due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	Years Ended December 31,					
	2004		2003		2002	
	MMCFE Change	Percent of total Additons	MMCFE Change	Percent of total Additons	MMCFE Change	Percent of total Additons
Revisions resulting from price changes	16,206	11%	6,750	3%	33,931	20%
Revisions resulting From performance	(26,127)	(18)%	14,290	6%	(7,569)	(4)%
Total	(9,921)	(7)%	21,040	9%	26,362	16%

Over the three-year period, we added 537.0 million MCFE of reserves, and 56.9 million MCFE, or 11 percent, were a result of price changes. A 19.4 million MCFE, or four percent, reduction in reserves was a result of changes in estimates based on the performance of our oil and gas properties. As previously noted, oil and gas prices are volatile and estimates of reserves are inherently imprecise. Consequently, we anticipate we will continue to experience these types of changes.

The following table reflects the estimated MMCFE change and percentage change to our reported reserve volumes from the described hypothetical changes:

	Years Ended December 31,					
	2004		2003		2002	
	MMCFE Change	Percent Change	MMCFE Change	Percent Change	MMCFE Change	Percent Change
A 10% decrease in pricing	16,672	3%	9,479	2%	8,700	2%
A 10% decrease in proved undeveloped reserves	9,839	1%	6,744	1%	6,043	1%

Additional reserve information can be found in the reserve table and discussion included in Item 1 of Part I of this report.

Successful efforts method of accounting. Generally accepted accounting principles provide for two alternative methods for the oil and gas industry to use in accounting for oil and gas producing activities. These two methods are generally known in our industry as the full cost method and the successful efforts method. Both methods are widely used. The methods are different enough that in many circumstances the same set of facts will provide materially different financial statement results within a given year. We have chosen the successful efforts method of accounting for our oil and gas producing activities, and a detailed description is included in Note 1 of Part IV, Item 15 of this report.

Revenue recognition. Our revenue recognition policy is significant because revenue is a key component of our results of operations and our forward-looking statements contained in our analyses of liquidity and capital resources. We derive our revenue primarily from the sale of produced natural gas and crude oil. We report revenue gross for the amounts we receive before taking into account production taxes and transportation costs which are reported as separate expenses. 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 month we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties; their historical performance; the anticipated effect of weather conditions during the month of production; 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. A 10 percent change in our year-end revenue accrual would have impacted net income before tax by $7.9 million in 2004.

Crude oil and natural gas hedging. Our crude oil and natural gas hedging contracts will usually qualify for cash flow deferral hedge accounting under SFAS No. 133. This policy is significant because it affects the timing of revenue recognition in our statements of operations and is discussed prominently in our forward-looking statements contained in our discussions of liquidity and capital resources. Under this accounting pronouncement a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred as to statement of operations recognition. The position reflected in the statement of operations is based on the actual settlements with the counterparty. If our natural gas and crude oil hedge contracts did not qualify for hedge accounting treatment or we chose not to use this hedge accounting methodology, our periodic statements of operations could include significant changes in the estimate of non-cash derivative gain or loss due to swings in the value of these contracts. Consequently we would report a different amount for oil and gas hedge loss in our statements of operations. These fluctuations could be especially significant in a volatile pricing environment such as we have encountered over the last three years. Net income after tax would have increased or (decreased) for 2004, 2003 and 2002 by the following amounts: $2.6 million, $(14.3 million), and $(6.3 million), respectively.

Asset retirement obligations. Under SFAS No. 143, Accounting for Asset Retirement Obligations, we are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. We base our estimate of the liability on our historical experience in abandoning oil and gas wells projected into the future based on our current understanding of federal and state regulatory requirements. Our projections require us to estimate economic lives of our properties, future inflation rates applied to external estimates as well as a credit adjusted risk-free rate to use in present value calculations. The statement of operations impact of this calculation is reflected in our depreciation, depletion and amortization calculations and occurs over the remaining life of our oil and gas properties.

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 or the carrying value will not be realized. We evaluate the realizability of our proved properties and other long-lived assets whenever events or changes in circumstances indicate that impairment may be appropriate. 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 discount rate that we believe is indicative of the current market. Our criteria for an acceptable internal rate of return are subject to change over time. Different pricing assumptions or discount rates could result in a different calculated impairment.

Change in Net Profits Plan liability. We record the estimated liability of future payments under our net profits plan because it is a vested employee benefit. The estimated liability is calculated based on a number of interrelated assumptions we control, including estimates of oil and gas reserves, recurring and workover lease operating expense, tax rates, present value discount factors and certain pricing assumptions. The estimates we use in calculating the liability are modified by us from reporting period to reporting period based on new information attributable to the underlying assumptions. Changes in the estimated liability of future payments associated with this plan are recorded as increases or decreases to expense in the current period. Changes in estimated future pricing, the costs of operating properties, tax rates, reserve quantities, production rates, or discount factors could have a material impact on the calculated liability and our consolidated statements of operations. Changes in the expense caused by changes in the underlying estimates are recorded in the period that the estimates change. A significant component of the estimated future liability is based on oil and gas pricing. A 10 percent increase to the pricing assumptions used in the measurement of this liability at December 31, 2004 would have decreased net income before taxes by $8.1 million in 2004.

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 in accordance with SFAS No. 109, Accounting for Income Taxes. 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. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Additionally, 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 and capital loss carryforwards and carrybacks. 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. These adjustments and changes in our estimates of asset recovery could have an impact on our results of operations. A one percent change in our effective tax rate would have affected our calculated income tax expense by $1.5 million for the year ended December 31, 2004.

Stock based compensation. We account for stock-based compensation using the intrinsic value recognition and measurement principles detailed in

Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees. No stock-based employee compensation expense relating to stock options has been reflected in our general and administrative expense as all options granted under our plans had an exercise price equal to the market value of the underlying common stock on the date of grant. We currently use the Black-Scholes option valuation model to calculate required disclosures under SFAS No. 123. In December 2004 the FASB issued SFAS No. 123(R), Shared-Based Payment. This statement provides for the accounting for transactions in which an entity exchanges equity instruments or incurs liabilities in exchange for goods or services. The statement is effective for us as of July 1, 2005. Following implementation, we anticipate that we will have expense associated with unvested options totaling $5.7 million that must be recorded in future periods under the modified-prospective method.

Additional Comparative Data in Tabular Format:

Oil and Gas Production Revenues:	Change Between Years 2004 and 2003	2003 and 2002
Increase in oil and gas production revenues (in thousands)	$ 48,204	$ 179,444
Components of Revenue Increases (Decreases):		
Natural Gas		
Price change per Mcf	$ 0.63	$ 1.89
Price percentage change	13%	63%
Production change (MMcf)	(3,065)	11,499
Production percentage change	(6)%	30%
Oil		
Price change per Bbl	$ 5.57	$ 1.62
Price percentage change	21%	6%
Production change (MBbl)	258	1,726
Production percentage change	6%	61%

Our product mix as a percentage of total oil and gas revenue and production:

	Years Ended December 31, 2004	2003	2002
Revenue			
Natural Gas	59%	66%	63%
Oil	41%	34%	37%
Production			
Natural Gas	62%	65%	69%
Oil	38%	35%	31%

Information regarding the effects of oil and gas hedging activity:

	Years Ended December, 31 2004	2003	2002
Natural Gas Hedging			
Percentage of gas production hedged	25%	40%	45%
Natural gas MMBtu hedged	12.9 million	21.7 million	18.9 million
(Decrease) in gas revenue	($15.5 million)	($11.4 million)	($4.1 million)
Average realized gas price per Mcf before hedging	$ 5.85	$ 5.12	$ 3.10
Oil Hedging			
Percentage of oil production hedged	45%	54%	54%
Oil volumes hedged (MBbl)	2,156	2,474	1,518
Increase (decrease) in oil revenue	($34.8 million)	($11.1 million)	$1.9 million
Average realized oil price per Bbl before hedging	$ 39.77	$ 29.40	$ 24.69

Information regarding the components of exploration expense:

	Years Ended December 31, 2004	2003	2002
Summary of Exploration Expense (In millions)			
Geological and geophysical expenses	$ 7.3	$ 5.1	$ 3.5
Exploratory dry holes	4.2	8.5	7.7
Overhead and other expenses	17.1	11.7	8.1
	$ 28.6	$ 25.3	$ 19.3

Comparison of Financial Results and Trends between 2004 and 2003

Oil and gas production revenues. Average net daily production decreased two percent to 206.0 MMCFE for 2004 compared with 210.7 MMCFE in 2003. Wells completed and properties acquired in 2003 and during 2004 have added revenue of $102.8 million and average net daily production of 38.2 MMCFE in 2004 compared to 2003. These increases are offset by natural declines in production from older properties and 3.9 MMCFE per day of 2003 production from properties that were sold in 2003.

Oil and gas hedge loss. As noted in the table above, the 124 percent increase in total oil and gas hedge loss to $50.3 million was caused by a 35 percent increase in the average pre-hedge oil price and a 14 percent increase in the pre-hedge gas price.

Oil and gas production expenses. Total production costs increased $7.0 million or eight percent to $95.5 million for 2004, from $88.5 million in 2003. Our acquisition of properties added $2.8 million of incremental production costs, and wells completed in 2003 and 2004 added $7.7 million of incremental production costs in 2004 that were not reflected in 2003. We experienced an increase in production taxes consistent with the increase in revenue from higher realized prices.

Total oil and gas production costs per MCFE increased $0.12 to $1.27 for 2004, compared with $1.15 for 2003. This increase is comprised of the following:

- A $0.07 increase in production taxes due to higher realized per MCFE prices;
- A $0.01 increase in transportation costs;
- A $0.01 decrease in LOE relating to workover charges;
- A $0.04 increase in LOE that reflects increasing costs in our Rocky Mountain region; and
- A $0.01 increase reflecting a general increases in LOE per MCFE in our other core areas.

Exploration expense. Exploration expense increased 13 percent in 2004. The most significant component of our increase to exploration expense was $5.5 million for exploration overhead we are incurring as we increase the size of our geologic and exploration staff.

General and administrative expense. General and administrative expenses increased $807,000 or four percent to $22.0 million for 2004, compared with $21.2 million in 2003. The increase in cost on a per MCFE basis of $0.01 reflects the effect of the four percent increase in G&A and a two percent decrease in production between the respective periods.

An increase in our employee count from 226 to 249 has resulted in a general increase in G&A of $4.2 million between 2004 and 2003. That increase plus a $913,000 increase in fees that are directly related to Sarbanes-Oxley compliance, and a $959,000 increase in other professional fees were offset by an

increase of $5.5 million of general and administrative expense we allocated to exploration expense.

Change in Net Profits Plan liability. This expense is the change in the net present value of estimated future incentive compensation payments to be made to plan participants under the computational provisions of the plan. During 2004 we determined that the expense adjustment related to the estimated future net profits plan liability should be presented separately from general and administrative and exploration expense because this liability is calculated based on the estimated net cash flows not yet realized from the future production of oil and gas and as such are not current expenses like general and administrative or exploration expense. This reclassification has the effect of reducing previously reported general and administrative expense and exploration expense to include only those amounts paid or accrued under the net profits plan that relate to current period oil and gas operations. For the year ended December 31, 2004, the expense related to the change in the estimated liability for this plan increased to $24.4 million from $5.3 million for 2003. This increase is due to the performance of individual pools, the effect of a higher price environment, and the application of lower discount rates to reflect the current economics of the market. Adjustments to the liability are subject to estimation and may change dramatically from year-to-year based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

Interest expense. Interest expense decreased by $1.7 million to $6.2 million for 2004 compared to $8.0 million for 2003. The decrease reflects the benefit of interest rate swaps we entered into on October 3, 2003, and decreased average borrowings under our credit facility in 2004 relative to the prior year.

Income tax expense. Income tax expense totaled $53.7 million for 2004 and $55.9 million in 2003, resulting in effective tax rates of 36.8 percent and 38.3 percent, respectively. The effective rate change from 2003 reflects percentage depletion and other permanent differences as well as changes in the composition of the highest marginal state tax rates as a result of acquisition and drilling activity. The cumulative effect of the change in marginal state tax rates that we recorded in 2004 was a result of filing our 2003 income tax returns and completing the evaluation of the impact on future temporary difference reversals.

The current portion of the income tax expense in 2004 is $22.5 million compared to $32.2 million in 2003. These amounts are 42 percent and 58 percent of the total tax for the respective periods. The difference results from decreased estimated taxable income caused by an increase in the estimated percentage of deductible intangible drilling costs relative to total income and the effect of an increase in stock option exercises. Unless the prices we receive for oil and gas change radically from our projections or we adjust the drilling portion of our budget, we estimate that the proportion of taxable income to book income will remain somewhat the same in 2005. Therefore, we believe that current taxable income will be lower and that the current portion of income tax as a percentage of total income tax will also remain somewhat the same.

Cumulative effect of change in accounting principal, net of income tax. On January 1, 2003 we adopted SFAS No. 143. The impact of adoption resulted in income to us of $8.8 million offset by the deferred income tax effect of $3.4 million. See Note 9 in Part IV, Item 15 of this report.

Comparison of Financial Results and Trends between 2003 and 2002

Oil and gas production revenues. Average net daily production increased 40 percent to 210.7 MMCFE for 2003 compared with 150.8 MMCFE in 2002. Included in our 2003 production volumes are 13.8 MMCFE from the Burlington and Flying J

acquisitions. Wells completed and acquired in 2002 and 2003 have added revenue of $135.3 million and average net daily production of 71.0 MMCFE in 2003 compared to 2002.

Oil and gas hedge loss. The $20.2 million increase in loss between 2003 and 2002 results from a combination of increased prices for oil and gas and an increase in the volumes we hedged as a result of our Burlington and Flying J property acquisitions.

Oil and gas production expenses. Total production costs increased $37.7 million to $88.5 million for 2003, from $50.8 million in 2002. Our acquisition of properties from Burlington and Flying J added $24.9 million of incremental production costs, and wells completed in 2002 and 2003 added $7.9 million of incremental production costs in 2003 that were not reflected in 2002. Additionally, we experienced an increase in production taxes consistent with the increase in revenue from higher realized prices.

Total oil and gas production costs per MCFE increased $0.23 to $1.15 for 2003, compared with $0.92 for 2002. This increase is comprised of the following:

- A $0.09 increase in production taxes due to higher realized per MCFE prices;
- A $0.03 increase due to rising transportation costs in our Rockies and Mid-Continent regions;
- A $0.03 increase in LOE relating to workover charges for projects in our Gulf Coast, Rocky Mountain and ArkLaTex regions;
- A $0.14 increase in LOE that reflects our addition of higher-cost oil properties in our Rocky Mountain region through acquisitions from Burlington and Flying J; and
- A $0.06 decrease reflecting general decreases in LOE per MCFE in our other core areas.

Exploration expense. Exploration expense increased 31 percent in 2003. The most significant component of our increase to exploration expense was $3.6 million for increased exploration overhead due to increases in our geologic and exploration staff as a result of the acreage we have acquired in the Williston, Green River, Wind River and Powder River basins and due to increases in our exploration-related incentive compensation.

General and administrative expense. General and administrative expenses increased $7.5 million or 55 percent to $21.2 million for 2003, compared with $13.7 million in 2002. The increase in cost on a per MCFE basis reflects a higher percentage increase in G&A than the proportionate increase in production of 40 percent for the period.

An increase in our employee count from 185 to 226 resulted in a general increase in G&A of $5.4 million between 2003 and 2002. That increase plus a $6.8 million increase in expense associated with our incentive compensation plans, a $1.0 million increase in accrued charitable contributions expense and a $539,000 increase in insurance and corporate governance costs were offset by a $6.9 million increase in COPAS overhead reimbursement from operations and G&A we allocated to exploration expense. COPAS overhead reimbursement from operations increased by $3.5 million due to 413 additional properties we operate in our Rocky Mountain region as a result of our Burlington and Flying J acquisitions. During 2003 we sold 74 of these properties. The increase in expense associated with our incentive compensation plans reflects both the benefit we received from the current price environment for past employee performance and the performance of our employees during that year.

Change in Net Profits Plan liability. The increase in the estimated liability resulted in expense of $5.3 million for the year ended December 31, 2003 compared to $846,000 for 2002.

Interest expense. Interest expense increased by $4.1 million to $8.0 million for 2003 compared to $3.9 million for 2002. The increase reflects a full year of accrued interest in 2003 on our convertible notes that were issued in March 2002, the benefit of an interest rate swap that reduced interest expense in 2002 by $839,000, the 0.5 percent contingent interest provision which applied in all of 2003 but for only 15 days during the comparable period in 2002, and increased borrowings under our credit facility in 2003 relative to the prior year.

Income tax expense. Income tax expense totaled $55.9 million for 2003 and $15.0 million in 2002, resulting in effective tax rates of 38.3 percent and 35.3 percent, respectively. The effective rate change from 2002 reflected an increase in our highest marginal federal tax rate, the expiration of the Section 29 tax credit, adjustments to valuation allowances to reflect the likelihood that prior Alternative Minimum Tax credits created by Section 29 credits will not be used, changes in the composition of the highest marginal state tax rates as a result of our recent acquisitions and the 2002 adjustment to valuation allowances against state income taxes from net operating loss carryovers.

The current portion of the income tax expense in 2003 was $32.2 million compared to $569,000 in 2002. These amounts are 58 percent and 4 percent of the total tax for the respective periods. The difference resulted from increased taxable income caused by significantly higher oil and gas prices and production, and a reduction in the percentage of deductible intangible drilling costs relative to total income.

Cumulative effect of change in accounting principal, net of income tax. On January 1, 2003 we adopted SFAS No. 143. The impact of adoption resulted in income to us of $8.8 million offset by the deferred income tax effect of $3.4 million. See Note 9 of the Notes to Consolidated Financial Statements under Part IV, Item 15 of this report.

Other Liquidity and Capital Resource Information

Common Stock Activity

On January 29, 2003, we financed the acquisition of oil and gas properties by issuing a total of 3,380,818 restricted shares of our common stock to Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. In addition, we made a non-recourse loan to Flying J and Big West in the amount of $71.6 million at LIBOR plus 2 percent for up to a 39-month period. We also entered into a put and call option agreement with Flying J whereby during the 39-month loan period Flying J could elect to put these shares to us for $71.6 million plus accrued interest on the loan during the first thirty months of the loan period, and we could elect to call the shares for $97.4 million, with the proceeds from the exercise of either the put option or the call option to be applied to the repayment of the loan. For financial reporting purposes the above arrangements were treated as an acquisition of properties in exchange for $71.6 million of cash plus the net option to Flying J valued at $1.0 million, resulting in a total valuation of $72.6 million. See Note 3 of Part IV, Item 15 of this report.

On February 9, 2004, we repurchased for $91.0 million the 3.4 million restricted shares of common stock. Flying J used the proceeds to repay their outstanding loan principal balance to us. Accrued interest on the loan, which was not recorded by us for financial reporting purposes due to the non-recourse nature of the loan, was forgiven. The $19.4 million net cash outlay was funded from our existing cash balance and borrowings under our credit facility. See Note 3 of Part IV, Item 15 of this report.

We reinitiated our stock repurchase program in August 2004. In the third quarter of 2004 we repurchased a total of 489,300 shares of our common stock for $16.3 million.

During 2004 we received net proceeds of $14.0 million from employee's and director's options exercises on 699,526 shares of common stock.

Pension Benefits

Substantially all of our employees who meet age and service requirements participate in a non-contributory defined benefit pension plan. At December 31, 2004, we have recorded a $746,000 pre-tax loss in accumulated other comprehensive income related to this plan. We believe this obligation will be funded from future cash flow from operating activities. For purposes of calculating our obligation under the plan, we have used an expected return on plan assets of eight percent. We think this rate of return is appropriate over the long-term given the 60 percent equity and 40 percent debt securities mix of investment for plan assets and the historical rate of return provided by equity and debt securities since the 1920s. Our estimated rate of return was 11.7 percent for 2004 and was 24.6 percent for 2003. The difference in investment income using our projected rate of return compared to our actual rates of return for the past two years was not material and will not have a material effect on statements of operation or cash flow from operating activities in future years.

For the 2004 plan year, a 0.50 percentage point decrease in the discount rate combined with a 0.50 percentage point increase in the rate of future compensation increases caused a $971,000 increase in the projected benefit obligation of the plan. We do not believe this change was material and project that it will not have a material effect on the results of operations or on cash flow from operating activities in future periods.

We also have a supplemental non-contributory defined benefit pension plan that covers certain management employees. There are no plan assets for this plan. For the 2004 plan year, a 0.50 percentage point decrease in the discount rate combined with a 0.50 percentage point increase in the rate of future compensation increases caused a $126,000 increase in the projected benefit obligation for this plan. This plan's accumulated benefit obligation was $1.2 million at December 31, 2004, and 2003. We believe this obligation will be funded from future cash flow from operating activities.

Accounting Matters

We recognized a $5.4 million gain net of income tax in 2003 from the adoption of SFAS No. 143 effective January 1, 2003.

In December 2004 the FASB issued a revision to SFAS No. 123. See Note 7 of Part IV, Item 15 of this report for more detailed discussion regarding the impact of adoption.

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

The information required by this item is provided under the captions "Interest Rate Market Risk" and "Sensitivity Analysis" in Item 7 above and is incorporated herein by reference.

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 15(a) of this report.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and to ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Vice-President - Finance, as appropriate to allow timely decisions regarding required disclosure.

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and the Vice-President - Finance, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K. Based upon that evaluation, the Chief Executive Officer and the Vice-President - Finance concluded that our disclosure controls and procedures are effective for the purposes discussed above as of the end of the period covered by this Annual Report on Form 10-K. There was no significant change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Stockholders' of St. Mary Land & Exploration Company

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Company's internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and

expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework.

Based on our assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2004.

The Company's independent auditors have issued an attestation report on management's assessment of the Company's internal controls over financial reporting. That report immediately follows this report.

/S/ MARK A. HELLERSTEIN	/S/ DAVID W. HONEYFIELD
Mark A. Hellerstein Chairman, CEO and President February 23, 2005	David W. Honeyfield Vice President-Finance, Secretary & Treasurer February 23, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that St. Mary Land & Exploration Company and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control--Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over

financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in Internal Control--Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control--Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2004, of the Company, and our report dated February 23, 2005, expressed an unqualified opinion on those financial statements.

/S/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2005

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 under the captions "Election of Directors" and "Nominees for Election of Directors" in St. Mary's definitive proxy statement for the 2005 annual meeting of stockholders to be filed within 120 days from December 31, 2004. The information required by this Item concerning St. Mary's executive officers is incorporated by reference to the information provided in Part I--Item 4A--EXECUTIVE OFFICERS OF THE REGISTRANT, included in this Form 10-K.

The information required by this Item concerning compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the information provided under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in St. Mary's definitive proxy statement for the 2005 annual meeting of stockholders to be filed within 120 days from December 31, 2004.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided under the captions, "Director Compensation," "Executive Compensation," "Report of the Compensation Committee on Executive Compensation," "Retirement Plans," "Performance Graph," and "Employee Agreements and Termination of Employment and Change-in-Control Arrangements" in St. Mary's definitive proxy statement for the 2005 annual meeting of stockholders to be filed within 120 days from December 31, 2004.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item concerning security ownership of certain beneficial owners and management is incorporated by reference to the information provided under the caption "Security Ownership of Certain Beneficial Owners and Management" in St. Mary's definitive proxy statement for the 2005 annual meeting of stockholders to be filed within 120 days from December 31, 2004.

The information required by this Item concerning securities authorized for issuance under equity compensation plans is incorporated by reference to the information provided under the caption "Equity Compensation Plans" in Part II - Item 5 - Market for Registrant's Common Equity and Related Stockholder Matters, included in this Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this Item is incorporated by reference to the information provided under the caption "Certain Relationships and Related Transactions" in St. Mary's definitive proxy statement for the 2005 annual meeting of stockholders to be filed within 120 days from December 31, 2004.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided under the caption "Independent Accountants" in St. Mary's definitive proxy statement for the 2005 annual meeting of stockholders to be filed within 120 days from December 31, 2004.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

Exhibit Number	Description
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 on March 27, 2003 (filed as Exhibit 3.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 and incorporated herein by reference)
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 for the quarter ended June 30, 1999 and incorporated herein by reference)
4.2	First Amendment to Shareholders Rights Plan dated March 15, 2002 as adopted by the Board of Directors on July 19, 2001 (filed as Exhibit 4.2 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference)
10.1	St. Mary Land & Exploration Company Stock Option Plan, As Amended on May 22, 2003 (filed as Exhibit 99.1 to the registrant's Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.2	St. Mary Land & Exploration Company Incentive Stock Option Plan, As Amended on March 25, 1999, January 27, 2000, March 29, 2001, March 27, 2003 and May 22, 2003 (filed as Exhibit 99.2 to registrant's Registration Statement on Form S-8 (Registration No. 333-106438) 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	Summary Plan Description/Pension Plan dated December 30, 1994 (filed as Exhibit 10.35 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1994 and incorporated herein by reference)
10.5	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)

Exhibit

Number	Description
10.6	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 (for the year ended December 31, 1997 and incorporated herein by reference)
10.7	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 for the quarter ended June 30, 2001 and incorporated herein by reference)
10.8	Form of Change of Control Severance Agreements (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001 and incorporated herein by reference)
10.9	Employment Agreement between Registrant and Mark A. Hellerstein (filed as Exhibit 10.15 to the registrant's Registration Statement on Form S-1 (Registration No. 33-53512) and incorporated herein by reference)
10.10	Registration Rights Agreement between St. Mary Land & Exploration Company and Bear, Stearns & Co. Inc., et al dated March 13, 2002 (filed as Exhibit 10.25 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference)
10.11	St. Mary Land & Exploration Company 5.75% Senior Convertible Notes Due 2002 Indenture dated March 13, 2002 (filed as Exhibit 10.26 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference)
10.12	Purchase and Sale Agreement dated October 1, 2002, effective as of July 1, 2002, between Burlington Resources Oil & Gas Company LP and The Louisiana Land and Exploration Company and Nance Petroleum Corporation (filed as Exhibit to the registrant's Current Report on Form 8-K filed on December 12, 2002 and incorporated herein by reference)
10.13	Purchase and Sale Agreement dated as of December 13, 2002 among Flying J Oil & Gas Inc., Big West Oil & Gas Inc., NPC Inc. and St. Mary Land & Exploration Company (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on February 13, 2003 and incorporated herein by reference)
10.14	Addendum dated January 29, 2003 to Purchase and Sale Agreement dated December 13, 2002 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on February 13, 2003 and incorporated herein by reference)
10.15	Nonrecourse Secured Promissory Note dated January 29, 2003 by Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on February 13, 2003 and incorporated herein by reference)
10.16	Stock Pledge Agreement from Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. to St. Mary Land & Exploration Company executed as of January 29, 2003 (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on February 13, 2003 and incorporated herein by reference)
10.17	Registration Rights Agreement dated as of January 29, 2003 among St. Mary Land & Exploration Company, Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. (filed as Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on February 13, 2003 and incorporated herein by reference)
10.18	Put and Call Option Agreement dated as of January 29, 2003 among St. Mary Land & Exploration Company, Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. (filed as Exhibit 10.6 to the registrant's Current Report on Form 8-K filed on February 13, 2003 and incorporated herein by reference)

Exhibit Number	Description
10.19	Standstill Agreement dated as of January 29, 2003 among St. Mary Land & Exploration Company, Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. (filed as Exhibit 10.7 to the registrant's Current Report on Form 8-K filed on February 13, 2003 and incorporated herein by reference)
10.20	Share Transfer Restriction Agreement dated as of January 29, 2003 among St. Mary Land & Exploration Company, Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. (filed as Exhibit 10.8 to the registrant's Current Report on Form 8-K filed on February 13, 2003 and incorporated herein by reference)
10.21	Indemnity Guarantee Agreement dated January 29, 2003 between NPC Inc. and Flying J Inc. (filed as Exhibit 10.9 to the registrant's Current Report on Form 8-K filed on February 13, 2003 and incorporated herein by reference)

10.22	Security Agreement made as of May 1, 2002 by St. Mary Land & Exploration Company, St. Mary Operating Company, St. Mary Energy Company, Nance Petroleum Corporation, St. Mary Minerals Inc., Parish Corporation, Four Winds Marketing LLC, and Roswell LLC, in favor of Bank of America, N.A. (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 and incorporated herein by reference)
10.23	Stock Pledge Agreement made as of May 1, 2002 by St. Mary Land & Exploration Company in favor of Bank of America, N.A. (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 and incorporated herein by reference)
10.24	LLC Pledge Agreement made as of May 1, 2002 by St. Mary Land & Exploration Company in favor of Bank of America, N.A. (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 and incorporated herein by reference)
10.25	Guaranty made as of May 1, 2002 by St. Mary Operating Company, St. Mary Energy Company, Nance Petroleum Corporation, St. Mary Minerals, Inc., Parish Corporation, Four Winds Marketing LLC and Roswell LLC in favor of Bank of America, N.A. (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 and incorporated herein by reference)
10.26	Credit Agreement dated as of January 27, 2003 among St. Mary Land & Exploration Company, Wachovia Bank, National Association of Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.44 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference)
10.27	Amendment to and Extension of Office Lease dated as of December 14, 2001 (filed as Exhibit 10.45 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference)
10.28	St. Mary Land & Exploration Company Non-Employee Director Stock Compensation Plan as adopted on March 27, 2003 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.29	Guaranty Agreement by St. Mary Energy Company in favor of Wachovia Bank, National Association, as Administrative Agent, dated January 27, 2003 (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.30	Guaranty Agreement by St. Mary Operating Company in favor of Wachovia Bank, National Association, as Administrative Agent, dated January 27, 2003 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)

Exhibit Number	Description
10.31	Guaranty Agreement by Nance Petroleum Corporation in favor of Wachovia Bank, National Association, as Administrative Agent, dated January 27, 2003 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.32	Guaranty Agreement by NPC Inc. in favor of Wachovia Bank, National Association, as Administrative Agent, dated January 27, 2003 (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.33	Pledge and Security Agreement between St. Mary Land & Exploration Company and Wachovia Bank, National Association, as Administrative Agent, dated January 27, 2003 (filed as Exhibit 10.8 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.34	Pledge and Security Agreement between Nance Petroleum Corporation and Wachovia Bank, National Association, as Administrative Agent, dated January 27, 2003 (filed as Exhibit 10.9 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.35	First Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of January 27, 2003 (filed as Exhibit 10.10 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.36	Deed of Trust - St. Mary Land & Exploration to Wachovia Bank, National Association, as Administrative Agent, dated effective as of January 27, 2003 (filed as Exhibit 10.11 to

	the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.37	Deed of Trust (CO, NV, SD) to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 2003 (filed as Exhibit 10.12 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.38	Deed of Trust (LA, MT, ND, NM, OK, TX, UT, WY) to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 2003 (filed as Exhibit 10.13 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.39	First Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 2003 (filed as Exhibit 10.14 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.40	Second Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 2003 (filed as Exhibit 10.15 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)

Exhibit Number	Description
10.41	First Amendment to Credit Agreement dated January 27, 2003 among St. Mary Land & Exploration Company, Wachovia Bank, National Association as Issuing Bank and Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference)
10.42	Net Profits Interest Bonus Plan, As Amended on February 3, 2004 (filed as Exhibit 10.42 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference)
10.43	St. Mary Land & Exploration Company Restricted Stock Plan as adopted on April 18, 2004 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference)
10.44	Second Amendment to Credit Agreement dated September 20, 2004 among St. Mary Land & Exploration Company, Wachovia Bank, National Association as Issuing Bank and Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004 and incorporated herein by reference)
10.45	Third Amendment to Credit Agreement dated October 20, 2004 among St. Mary Land & Exploration Company, Wachovia Bank, National Association as Issuing Bank and Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004 and incorporated herein by reference)
10.46	Form of Restricted Stock Unit Award Memorandum under the St. Mary Land & Exploration Company Restricted Stock Plan (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004 and incorporated herein by reference)
10.47*	Attachment A to Form of Change of Control Severance Agreement
10.48*	Second Amendment to the St. Mary Land & Exploration Employee Stock Puchase Plan dated February 18, 2005
12.1*	Computation of Ratio of Earnings to Fixed Charges
14.1	Code of Business Conduct and Ethics
21.1*	Subsidiaries of Registrant
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Ryder Scott Company, L.P.
23.3*	Consent of Netherland, Sewell & Associates, Inc.
24.1*	Power of Attorney (included in signature page hereof)
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
31.2*	Certification of Vice President - Finance pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
32.1*	Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002

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* Filed with this Form 10-K.

(c) Financial Statement Schedules. See Item 15(a) above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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 and subsidiaries (the "Company") as of December 31, 2004 and 2003, 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, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (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, such consolidated financial statements present fairly, in all material respects, the financial position of St. Mary Land & Exploration Company and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 9 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations in 2003 with the implementation of Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations".

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control--Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 23, 2005, expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/S/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2005

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

	December 31,	
ASSETS	2004	2003
Current assets:		
Cash and cash equivalents	$ 6,418	$ 14,827
Short-term investments	1,412	12,509
Accounts receivable	104,964	64,540
Prepaid expenses and other	5,863	6,564
Deferred income taxes	-	8,872
Accrued derivative asset	8,270	157
Other	-	454
Total current assets	126,927	107,923
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	1,124,810	858,246
Less - accumulated depletion, depreciation and amortization	(399,013)	(312,719)
Unproved oil and gas properties, net of impairment allowance of $9,867 in 2004 and $10,776 in 2003	41,969	36,793
Wells in progress	35,515	24,691
Other property and equipment, net of accumulated depreciation of $6,459 in 2004 and $4,656 in 2003	5,244	4,276
	808,525	611,287
Other noncurrent assets	10,008	16,644
Total Assets	$ 945,460	$ 735,854

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities:

Accounts payable and accrued expenses	$ 110,117	$ 81,217
Accrued derivative liability	2,502	23,605
Deferred income taxes	2,273	-
Total current liabilities	114,892	104,822
Noncurrent liabilities:		
Long-term credit facility	37,000	11,000
Convertible notes	99,791	99,696
Asset retirement obligation	40,911	25,485
Net Profits Plan liability	30,561	6,163
Deferred income taxes	129,830	90,947
Other noncurrent liabilities	8,020	7,088
Total noncurrent liabilities	346,113	240,379
Commitments and contingencies (Note 6):		
Temporary equity (Note 3):		
Common stock subject to put and call options, $0.01 par value; issued and outstanding: -0- shares in 2004 and 3,380,818 shares in 2003	-	71,594
Note receivable from Flying J	-	(71,594)
Total temporary equity	-	-
Stockholders' equity:		
Common stock, $0.01 par value: authorized - 100,000,000 shares; issued: 28,729,123 shares in 2004 and 29,245,123 shares in 2003; outstanding, net of treasury shares: 28,479,123 shares in 2004 and 28,242,423 shares in 2003	287	292
Additional paid-in capital	127,661	146,362
Treasury stock, at cost: 250,000 shares in 2004 and 1,002,700 shares in 2003	(5,295)	(16,057)
Deferred stock-based compensation	(5,039)	-
Retained earnings	364,567	274,937
Accumulated other comprehensive income (loss)	2,274	(14,881)
Total stockholders' equity	484,455	390,653
Total Liabilities and Stockholders' Equity	$ 945,460	$ 735,854

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

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

	For the Years Ended December 31,		
	2004	2003	2002
Operating revenues:			
Oil and gas production	$ 463,617	$ 387,553	$ 187,905
Oil and gas hedge loss	(50,299)	(22,439)	(2,235)
Gain(loss) on sale of proved properties	1,803	7,278	(2,633)
Marketed gas revenue	15,551	13,438	8,399
Other oil and gas revenue	2,342	3,538	682
Derivative gain	-	-	3,188
Other revenue	85	4,340	999
Total operating revenues	433,099	393,708	196,305
Operating expenses:			
Oil and gas production	95,518	88,509	50,839
Depletion, depreciation, amortization and abandonment liability accretion	92,223	81,960	54,432
Exploration	28,560	25,318	19,271
Impairment of proved properties	494	185	-
Abandonment and impairment of unproved properties	1,420	3,796	2,446
General and administrative	22,004	21,197	13,683
Change in Net Profits Plan liability	24,398	5,317	846
Marketed gas system operating expense	14,230	12,229	7,982
Derivative loss	260	310	-
Other	2,077	1,576	1,117
Total operating expenses	281,184	240,397	150,616
Income from operations	151,915	153,311	45,689
Nonoperating income(expense):			
Interest income	557	717	758
Interest expense	(6,244)	(7,958)	(3,868)

Income before income taxes and cumulative effect of change in accounting principle	146,228	146,070	42,579
Income tax expense	(53,749)	(55,930)	(15,019)
Income before cumulative effect of change in accounting principle	92,479	90,140	27,560
Cumulative effect of change in accounting principle, net of income tax	-	5,435	-
Net income	$ 92,479	$ 95,575	$ 27,560
Basic weighted-average common shares outstanding	28,851	31,233	27,856
Diluted weighted-average common shares outstanding	33,447	35,534	28,391
Basic earnings per common share:			
Income before cumulative effect of change in accounting principle	$ 3.21	$ 2.89	$ 0.99
Cumulative effect of change in accounting principle, net of income tax	-	0.17	-
Basic net income per common share	$ 3.21	$ 3.06	$ 0.99
Diluted earnings per common share:			
Income before cumulative effect of change in accounting principle	$ 2.88	$ 2.65	$ 0.97
Cumulative effect of change in accounting principle, net of income tax	-	0.15	-
Diluted net income per common share	$ 2.88	$ 2.80	$ 0.97
Cash dividends declared per common share	$ 0.10	$ 0.10	$ 0.10

The accompanying notes are an integral part to 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 Capital	Treasury Stock		Deferred Stock-Based Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount				
Balances, December 31, 2001	28,779,808	$ 288	$137,384	(1,009,900)	$(16,210)	$ -	$157,739	$ 6,916	$ 286,117
Comprehensive income:									
Net income	-	-	-	-	-	-	27,560	-	27,560
Unrealized net loss on marketable equity securities available for sale	-	-	-	-	-	-	-	(725)	(725)
Change in derivative instrument fair value	-	-	-	-	-	-	-	(14,644)	(14,644)
Reclassification to earnings	-	-	-	-	-	-	-	1,447	1,447
Minimum pension liability adjustment	-	-	-	-	-	-	-	(761)	(761)
Total comprehensive income									12,877
Cash dividends declared, $ 0.10 per share	-	-	-	-	-	-	(2,787)	-	(2,787)
Issuance of common stock under Employee Stock Purchase Plan	18,217	-	344	-	-	-	-	-	344
ESPP disqualified distribution	-	-	21	-	-	-	-	-	21
Sale of common stock, including income tax benefit of stock option exercises	177,085	2	2,743	-	-	-	-	-	2,745
Accelerated vesting of retiring director's options	-	-	52	-	-	-	-	-	52
Directors' stock compensation	8,000	-	144	-	-	-	-	-	144
Balances, December 31, 2002	28,983,110	$ 290	$140,688	(1,009,900)	$(16,210)	$ -	$182,512	$ (7,767)	$ 299,513
Comprehensive income:									
Net income	-	-	-	-	-	-	95,575	-	95,575
Unrealized net gain on marketable equity securities available for sale	-	-	-	-	-	-	-	716	716
Change in derivative instrument fair value	-	-	-	-	-	-	-	(21,873)	(21,873)
Reclassification to earnings	-	-	-	-	-	-	-	13,846	13,846
Minimum pension liability adjustment	-	-	-	-	-	-	-	197	197
Total comprehensive income									88,461
Cash dividends declared, $ 0.10 per share	-	-	-	-	-	-	(3,150)	-	(3,150)
Issuance of common stock									

under Employee Stock Purchase Plan	16,994	-	375	-	-	-	-	-	375
Value of option right granted to Flying J	-	-	995	-	-	-	-	-	995
Sale of common stock, including income tax benefit of stock option exercises	245,019	2	4,304	-	-	-	-	-	4,306
Directors' stock compensation	-	-	-	7,200	153	-	-	-	153
Balances, December 31, 2003	29,245,123	$ 292	$146,362	(1,002,700)	$(16,057)	$ -	$274,937	$ (14,881)	$ 390,653
Comprehensive income:									
Net income	-	-	-	-	-	-	92,479	-	92,479
Change in derivative instrument fair value	-	-	-	-	-	-	-	(14,795)	(14,795)
Reclassification to earnings	-	-	-	-	-	-	-	31,849	31,849
Minimum pension liability adjustment	-	-	-	-	-	-	-	101	101
Total comprehensive income									109,634
Cash dividends declared, $ 0.10 per share	-	-	-	-	-	-	(2,849)	-	(2,849)
Repurchase of common stock from Flying J	-	-	(19,406)	-	-	-	-	-	(19,406)
Treasury stock purchases	-	-	-	(489,300)	(16,336)	-	-	-	(16,336)
Retirement of treasury stock	(1,229,400)	(12)	(26,737)	1,229,400	26,749	-	-	-	-
Issuance of common stock under Employee Stock Purchase Plan	13,874	-	375	-	-	-	-	-	375
Sale of common stock, including income tax benefit of stock option exercises	699,526	7	17,839	-	-	-	-	-	17,846
Deferred compensation related to issued restricted stock unit awards	-	-	8,122	-	-	(8,122)	-	-	-
Accrued stock-based compensation	-	-	1,106	-	-	-	-	-	1,106
Amortization of deferred stock-based compensation	-	-	-	-	-	3,083	-	-	3,083
Directors' stock compensation	-	-	-	12,600	349	-	-	-	349
Balances, December 31, 2004	28,729,123	$ 287	$127,661	(250,000)	$ (5,295)	$ (5,039)	$364,567	$ 2,274	$ 484,455

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

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

	For the Years Ended December 31,		
	2004	2003	2002
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 92,479	$ 95,575	$ 27,560
Adjustments to reconcile net income to net cash provided by operating activities:			
(Gain) loss on sale of proved properties	(1,803)	(7,278)	2,633
Depletion, depreciation, amortization and abandonment liability accretion	92,223	81,960	54,432
Exploratory dry hole expense	4,162	8,482	7,677
Impairment of proved properties	494	185	-
Abandonment and impairment of unproved properties	1,420	3,796	2,446
Unrealized derivative loss	260	310	373
Change in Net Profits Plan liability	24,398	5,317	846
Deferred and accrued stock-based compensation	4,189	-	-
Income tax benefit from the exercise of stock options	3,816	1,151	719
Deferred income taxes	39,573	20,536	13,914
Other	(1,948)	2,088	(1,642)
Cumulative effect of change in accounting principle, net of tax	-	(5,435)	-
Changes in current assets and liabilities:			
Accounts receivable	(39,880)	(29,685)	11,085
Prepaid expenses and other	157	490	(4,173)
Accounts payable and accrued expenses	17,622	26,827	25,839
Net cash provided by operating activities	237,162	204,319	141,709
Cash flows from investing activities:			
Proceeds from sale of oil and gas properties	2,829	23,497	1,624
Capital expenditures	(199,385)	(123,823)	(97,257)
Acquisition of oil and gas properties, including related $71,594 loan to Flying J in 2003	(68,805)	(76,413)	(87,466)
Deposits to short-term investments available-for-sale	(1,470)	(12,529)	(13,523)
Receipts from short-term investments available-for-sale	12,500	2,450	12,538
Receipts from restricted cash	10,353	11,500	-
Deposits to restricted cash	-	(21,853)	-
Other	(3,028)	232	3,153

Net cash used in investing activities	(247,006)	(196,939)	(180,931)
Cash flows from financing activities:			
Proceeds from credit facility	181,497	140,933	37,400
Repayment of credit facility	(155,500)	(145,020)	(87,400)
Proceeds from issuance of convertible debt	-	-	96,657
Proceeds from sale of common stock for exercise of stock options	14,030	3,530	2,390
Repurchase of common stock	(35,743)	-	-
Dividends paid	(2,849)	(3,150)	(2,787)
Net cash provided by (used in) financing activities	1,435	(3,707)	46,260
Net change in cash and cash equivalents	(8,409)	3,673	7,038
Cash and cash equivalents at beginning of period	14,827	11,154	4,116
Cash and cash equivalents at end of period	$ 6,418	$ 14,827	$ 11,154

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

Supplemental schedule of additional cash flow information and noncash investing and financing activities:

	For the Years Ended December 31,		
	2004	2003	2002
		(in thousands)	
Cash paid for interest, including amounts capitalized	$ 8,859	$ 7,555	$ 2,498
Cash paid (refunded) for income taxes	14,787	28,858	(550)

In August 2004 the Company closed a transaction whereby it exchanged oil and gas properties valued at $1.4 million together with $769,000 of cash for oil and gas properties valued at $2.2 million.

In June 2004 the Company issued 232,861 restricted stock units pursuant to the Company's restricted stock plan. The total value of the grant was $8.3 million, which as of December 31, 2004 has been reduced by $178,000 for forfeitures. The Company has recorded compensation expense related to the 2004 grant of $3.1 million for the year ended December 30, 2004.

In January 2004 and May 2004 the Company issued 4,200 shares and 8,400 shares, respectively, of common stock from treasury to its non-employee directors pursuant to the Company's non-employee director stock compensation plan. The Company recorded compensation expense of $349,000 for year ended December 31, 2004.

In January 2003 the Company issued 7,200 shares of common stock from treasury to its non-employee directors and recorded compensation expense of $153,000.

In January 2003 the Company issued 3,380,818 restricted shares of common stock to Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. (collectively, "Flying J") and entered into a put and call option agreement, valued at $995,000 for financial reporting purposes, with Flying J with respect to those shares in connection with the acquisition of oil and gas properties and related assets and liabilities.

In June 2002 the Company issued 800 shares of common stock to a non-employee director and recorded compensation expense of $14,763.

In April 2002 the Company accepted 9,472,562 shares of common stock in Constellation Copper Corporation ("Constellation", formerly known as Summo Minerals Corporation) in lieu of cash payment for the relief of a $1,400,000 loan and $15,311 in interest due to the Company.

In January 2002 the Company issued 7,200 shares of common stock to its non-employee directors and recorded compensation expense of $129,683.

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

Note 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, exploitation, development, acquisition and production of natural gas and crude oil. The Company's operations are conducted entirely in the continental United States.

Basis of Presentation

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. Equity method investments are included in other noncurrent assets, and minority interest is included in other noncurrent liabilities in the accompanying consolidated balance sheets. All significant intercompany accounts and transactions have been eliminated

Certain amounts in 2003 and 2002 financial statements have been reclassified to conform to the 2004 financial statement presentation. The non-cash portion of Net Profits Interest Bonus Plan (the "Net Profits Plan") expense and the corresponding liability have been reclassified as separate line items in the accompanying financial statements for all periods presented. As a result, prior period general and administrative expense, exploration expense and other non-current liabilities have been reclassified to conform to the current presentation. Additionally, wells in progress have been classified as a separate line item in the consolidated balance sheets for all periods presented. As a result, prior period unproved oil and gas properties, net of impairment allowance, have been reclassified to conform to the current presentation.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the 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

Cash and Cash Equivalents

The Company considers all 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 due to the short-term nature of these instruments.

Short-term Investments

The Company's short-term investments consist primarily of investment-grade marketable debt, which is classified as available-for-sale. Securities that have been categorized as available-for-sale are stated at fair value based on quoted market prices. The following table summarizes the estimated fair value of the components of the Company's available-for-sale short-term investments:

	As of December 31,	
	2004	2003
	(in thousands)	
Corporate debt securities	$ 1,412	$ 1,009
Escrowed cash	$ -	$ 11,500
Total	$ 1,412	$ 12,509

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 among many companies, collectability is dependent upon the financial wherewithal of each individual company as well as the general economic conditions of the industry. The receivables are not collateralized. To date the Company has had minimal bad debts.

The Company has accounts with separate banks in Denver, Colorado; Shreveport, Louisiana; Tulsa, Oklahoma; Houston, Texas; and Billings, Montana. At December 31, 2004, 2003 and 2002, the Company had $22.2 million, $23.5 million, and $4.9 million respectively, invested in money market funds (including margin accounts) consisting of corporate commercial paper, repurchase agreements and U.S. Treasury obligations. The difference between the investment amount and the cash and cash equivalents amount on the consolidated balance sheets, represents uncleared disbursements. 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 as part of capital expenditures within the consolidated statements of cash flows. The costs of development wells are capitalized whether productive or nonproductive. The Company had no exploratory well costs that had been suspended for one year or more as of December 31, 2004 or 2003.

Geological and geophysical costs and the costs of carrying and retaining unproved properties are expensed as incurred. 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. As of December 31, 2004, the Company's capitalized proved oil and gas properties included $51.2 million of estimated salvage value, which is excluded from the Company's DD&A calculation. On January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations," which provides guidance on accounting for dismantlement and abandonment costs (see Note 9 - Asset Retirement Obligations).

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 for proved properties 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 discount rate and price forecasts selected by the Company's management. The discount rate is a rate that management believes is representative of current market conditions. The price forecast is based on NYMEX strip pricing for the first three years and is then escalated to specified maximum prices. Operating costs are escalated in these estimates. When the net capitalized costs exceed the undiscounted future net revenues of a field, the cost of the field is reduced to fair value, which is determined using discounted future net revenues. An impairment allowance is provided on unproved property when the Company determines that the property will not be developed or that the carrying value is not realizable.

Sales of Proved and Unproved 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 units-of-production depletion 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. A gain or loss is recognized for all other sales of nonproducing properties and is included in the results of operations.

Other Property and Equipment

Other property and equipment such as office furniture and equipment, automobiles and computer hardware and software 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 three to 15 years. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Gas Balancing

The Company uses the sales method to account for gas imbalances. Under this method, revenue is recorded based on 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 $1.5 million at December 31, 2004, and $1.2 million at December 31, 2003, are included in other noncurrent assets in the accompanying consolidated 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 $726,000 at December 31, 2004, and $500,000 at December 31, 2003, are included in other noncurrent liabilities in the accompanying consolidated balance sheets. Receivables and payables are valued based on prices used in recent settlements between the Company and its imbalance counterparties, and receivables are recorded net of collection allowance. The Company's remaining overproduced and underproduced gas balancing positions are considered in the Company's proved oil and gas reserves (see Note 12 - Disclosures about Oil and Gas Producing Activities).

Derivative Financial Instruments

The Company seeks to protect its rate of return on acquisitions of producing properties, and other production by hedging cash flows. The Company intends for derivative instruments used for this purpose to be designated as, and to qualify as, cash flow hedging instruments under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and related pronouncements. The Company generally limits its aggregate hedge position to no more than 50 percent of its total production but will hedge larger percentages 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 - Derivative Financial Instruments for additional discussion of derivatives.

Fair Value of Financial Instruments

The Company's financial instruments including cash and cash equivalents, restricted cash, accounts receivable and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The recorded value of the Company's credit facility approximates its fair value as it bears interest at a floating rate. The Company's interest rate swaps are recorded at fair value as discussed in Note 10 - - Derivative Financial Instruments. The Company's 5.75% Senior Convertible Notes Due 2022 (the "Convertible Notes") are recorded at cost, and the fair value is disclosed in Note 5 - Long-Term Debt. The Company's other financial instruments and investments in available-for-sale securities are marked to market with changes in fair value being recorded in accumulated other comprehensive income. Since considerable judgment is required to develop estimates of fair value, the estimates provided are not necessarily indicative of the amounts the Company could realize upon the sale or refinancing of such instruments.

Net Profits Plan

The Company records the estimated liability of future payments under its Net Profits Plan because it is a vested employee benefit. The estimated liability is calculated based on a number of assumptions, including estimates of oil and gas reserves, recurring and workover lease operating expense, tax rates, present value discount factors and certain pricing assumptions. The estimates the Company uses in calculating the liability are modified from period to period based on new information attributable to the underlying assumptions. Changes in the estimated liability of future payments associated with the Net Profits Plan are recorded as increases or decreases to expense in the current period as a separate line item in the consolidated statements of operations. The estimated Net Profits Plan liability is recorded separately as a noncurrent liability in the accompanying consolidated balance sheets.

The amounts due and payable under the Net Profits Plan as cash compensation related to the current period operations are recognized as compensation expense and are included within general and administrative expense and exploration expense. The corresponding current liability is included in accounts payable and accrued expenses in the accompanying consolidated balance sheets. This treatment provides for a consistent matching of cash expense with net cash flows from the oil and gas properties in each respective pool of the Net Profits Plan.

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 available to common stockholders by the weighted-average of common shares outstanding during each period.

During the first quarter of 2003, the Company issued 3,380,818 shares of common stock as part of an acquisition. On February 9, 2004, the Company repurchased and retired these shares (see Note 11-Repurchase of St. Mary Common Stock). These shares were considered outstanding from January 29, 2003, to February 9, 2004, for purposes of calculating basic and diluted net income per common share and were weighted accordingly in the calculation of common shares outstanding. The shares were included in the temporary equity section of the consolidated balance sheet as of December 31, 2003.

Diluted net income per common share of stock is calculated by dividing adjusted net income by the weighted-average of common shares outstanding, including the effect of other dilutive securities. Adjusted net income is used for the if-converted method and is derived by adding interest expense paid on the Convertible Notes back to net income and then adjusting for nondiscretionary items that are based on income and that would have changed had the Convertible Notes been converted at the beginning of the period. Potentially dilutive securities of the Company consist of in-the-money outstanding options to purchase the Company's common stock, shares into which the Convertible Notes may be converted and unvested restricted stock units.

The shares underlying the grants of restricted stock units are excluded from basic and diluted earnings per share until the measurement date for grants made under the Restricted Stock Plan. Upon measurement, all unvested shares attributable to the restricted stock unit grant are included in the diluted share calculation. Vested shares are included in both basic and diluted earnings per share.

The treasury stock method is used to measure the dilutive impact of stock options. The following table details the weighted-average dilutive and anti-dilutive securities related to stock options for the periods presented:

	For the Years Ended December 31,		
	2004	2003	2002
Dilutive	749,644	455,055	534,610
Anti-dilutive	93	713,382	1,539,227

The dilutive effect of stock options and unvested restricted stock units is considered in the detailed calculation below. There were no anti-dilutive securities related to restricted stock units for any periods presented.

Shares associated with the conversion feature of the Convertible Notes are accounted for using the if-converted method as described above. A total of 3,846,153 potentially dilutive shares related to the Convertible Notes were included in the calculation of diluted net income per common share for the years ended December 31, 2004 and 2003. A total of 3,076,922 potentially dilutive shares related to the Convertible Notes were excluded from the 2002 calculation of diluted net income per share because they were not dilutive. The Convertible Notes were issued in March 2002.

The following table sets forth the calculation of basic and diluted earnings per share:

	For the Years Ended December 31,		
	2004	2003	2002
	(In thousands, except per share amounts)		
Income before cumulative effect of change in accounting principle	$ 92,479	$ 90,140	$ 27,560
Cumulative effect of change in accounting principle, net of income tax	-	5,435	-
Net income	92,479	95,575	27,560
Adjustments to net income for dilution:			
Add: interest expense avoided if Convertible Notes converted to equity	6,354	6,337	-
Less: other adjustments	(64)	(63)	-
Less: income tax effect of dilution items	(2,312)	(2,403)	-
Net income adjusted for the effect of dilution	$ 96,457	$ 99,446	$ 27,560
Basic weighted-average common shares outstanding	28,851	31,233	27,856
Add: dilutive effect of stock options	750	455	535
Add: dilutive effect of Convertible Notes using the if-converted method	3,846	3,846	-
Diluted weighted-average common shares outstanding	33,447	35,534	28,391
Basic earnings per common share:			
Income before cumulative effect of change in accounting principle	$ 3.21	$ 2.89	$ 0.99
Cumulative effect of change in accounting principle	-	0.17	-
Total	$ 3.21	$ 3.06	$ 0.99

	2004	2003	2002
Diluted earnings per common share:			
Income before cumulative effect of change in accounting principle	$ 2.88	$ 2.65	$ 0.97
Cumulative effect of change in accounting principle	-	0.15	-
Total	$ 2.88	$ 2.80	$ 0.97

Stock-Based Compensation

At December 31, 2004, the Company had stock-based employee compensation plans that included restricted stock units and stock options issued to employees and non-employee directors as more fully described in Note 7 - Compensation Plans. The Company accounts for stock-based compensation using the intrinsic value recognition and measurement principles prescribed in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB No. 25") and related interpretations. No compensation expense is reflected in net income for stock options as all stock options had an exercise price equal to the market value of the underlying common stock on the date of grant. The total measured expense for restricted stock unit ("RSU") grants is initially recorded as deferred stock-based compensation and is charged to compensation expense based on the vesting schedule. The portion of the estimated future RSU grant related to current year performance that will vest immediately upon grant is recorded to compensation expense in the current year. The following table illustrates the pro forma effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation:

	For the Years Ended December 31,		
	2004	2003	2002
	(In thousands, except per share amounts)		
Net income -			
As reported:	$ 92,479	$ 95,575	$ 27,560
Add: stock-based employee compensation expense included in reported net income, net of related tax effects	2,650	-	-
Less: stock-based employee compensation expense determined under fair value method for all awards, net of related income tax effects	(6,062)	(5,853)	(4,666)
Pro forma	$ 89,067	$ 89,722	$ 22,894
Pro forma basic earnings per share -			
Income before cumulative effect of change in accounting principle	$ 3.09	$ 2.70	$ 0.82
Cumulative effect of change in accounting principle	-	0.17	-
Total	$ 3.09	$ 2.87	$ 0.82
Pro forma diluted earnings per share -			
Income before cumulative effect of change in accounting principle	$ 2.78	$ 2.48	$ 0.81
Cumulative effect of change in accounting principle	-	0.15	-
Total	$ 2.78	$ 2.63	$ 0.81

For purposes of pro forma disclosures, the estimated fair values of the options are amortized to expense over the options' vesting periods. The effects of applying SFAS No. 123 in the pro forma disclosure are not necessarily indicative of actual future amounts.

In December 2004 the Financial Accounting Standards Board ("FASB") issued SFAS No. 123 (Revised 2004), "Shared-Based Payment". This statement provides for the accounting for transactions in which an entity exchanges equity instruments or incurs liabilities in exchange for goods or services. See Note 7 - - Compensation Plans for additional disclosures about stock-based compensation.

Comprehensive Income

Comprehensive income consists of net income, unrealized gains and losses on marketable equity securities held for sale, the effective portion of derivative instruments classified as cash flow hedges, and accrued pension benefit obligation in excess of plan assets. Comprehensive income is presented net of income taxes in the consolidated statements of stockholders' equity and comprehensive income.

The balances of after-tax components comprising accumulated other comprehensive income and loss are presented in the following table:

	Marketable Equity Securities	Derivative Instruments	Minimum Pension Liability	Accumulated Other Comprehensive Income (Loss)
Balances, December 31, 2001	$ 9	$ 6,907	$ -	$ 6,916
Reclass to earnings	-	1,447	-	1,447
Other 2002 changes	(725)	(14,644)	(761)	(16,130)
Balances, December 31, 2002	(716)	(6,290)	(761)	(7,767)
Reclass to earnings	716	13,846	-	14,562
Other 2003 changes	-	(21,873)	197	(21,676)
Balances, December 31, 2003	-	(14,317)	(564)	(14,881)
Reclass to earnings	-	(14,795)	-	(14,795)
Other 2004 changes	-	31,849	101	31,950
Balances, December 31, 2004	$ -	$ 2,737	$ (463)	$ 2,274

Tax effects allocated to each component of other comprehensive income:

	Marketable Equity Securities	Derivative Instruments	Minimum Pension Liability	Other Comprehensive Income (Loss)
For the period ending December 31, 2002				
Before tax amount	$ (1,121)	$ (18,067)	$ (1,188)	$ (20,376)
Tax (expense) benefit	396	4,870	427	5,693
After tax amount	(725)	(13,197)	(761)	(14,683)
For the period ending December 31, 2003				
Before tax amount	1,160	(13,170)	274	(11,736)
Tax (expense) benefit	(444)	5,143	(77)	4,622
After tax amount	716	(8,027)	197	(7,114)
For the period ending December 31, 2004				
Before tax amount	-	27,401	168	27,569
Tax (expense) benefit	-	(10,347)	(67)	(10,414)
After tax amount	$ -	$ 17,054	$ 101	$ 17,155

Major Customers

During 2004 one customer individually accounted for 20 percent of the Company's total oil and gas production revenue. During 2003 three customers individually accounted for 14 percent, 13 percent and 11 percent of the Company's total oil and gas production revenue. During 2002 there were no sales to individual customers that accounted for more than 10 percent of 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 continental United States. Consequently, the Company currently reports as a single industry segment.

Note 2 - Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

	As of December 31, 2004	2003
	(In thousands)	
Accrued oil and gas sales	$ 79,107	$ 48,925
Due from joint interest owners	20,587	12,554
Other	5,270	3,061
Total accounts receivable	$ 104,964	$ 64,540

Accounts payable and accrued expenses are comprised of the following:

	As of December 31,	
	2004	2003
	(In thousands)	
Accrued drilling costs	$ 34,446	$ 22,201
Revenue payable	41,875	16,215
Accrued lease operating expense	13,066	12,195
Accrued cash bonus and net profit payments	4,264	8,026
Trade payables	7,506	6,247
Oil hedge accrual	3,027	1,400
Other	5,933	14,933
Total account payable and accrued expenses	$ 110,117	$ 81,217

Note 3 - Acquisitions and Divestitures

Goldmark Acquisition

On November 1, 2004, the Company acquired Goldmark Engineering Inc. along with proved and unproved oil and gas properties from various other parties (collectively, "Goldmark") in exchange for $23.3 million of cash. The allocation of the purchase price was $29.4 million of proved reserves and unproved acreage, $1.2 million of cash, $753,000 of other assets, $446,000 of payables, a $2.8 million asset retirement liability, and a $4.8 million deferred tax liability. The acquisition was accounted for using the purchase method of accounting and was funded with cash on hand and borrowings under the Company's existing credit facility. Operating results from the acquired properties have been included in the consolidated statements of operations only from the date of closing. The final purchase accounting allocations will be dependent on a determination of post closing adjustments incurred subsequent to the acquisition date.

Border Acquisition (Previously referred to by the Company as the Nemours Acquisition)

On December 15, 2004, the Company completed the acquisition of proved and unproved oil and gas properties from Border Company and other parties in exchange for $37.8 million in cash. The allocation of the purchase price was $38.5 million of proved reserves and unproved acreage and a $649,000 asset retirement obligation. The final purchase accounting allocations will be dependent on a determination of post closing adjustments incurred subsequent to the acquisition date. The Company utilized a portion of its existing credit facility to fund the acquisition, and the transaction was accounted for as a purchase.

Agate Acquisition

On January 5, 2005, the Company closed the acquisition of Agate Petroleum, Inc. for $39.6 million in cash. The estimated preliminary purchase accounting will result in the Company recording approximately $42.1 million to proved and unproved oil and gas properties, $3.0 million to working capital, $9.4 million to goodwill, a deferred income tax liability of $13.6 million and a $1.3 million asset retirement obligation. The final purchase accounting allocation will be dependent on the determination of working capital, tax basis and fair value of the oil and gas properties as of the date of closing. The goodwill and deferred income tax liability are a result of acquiring assets with tax basis that is lower than book basis because present value considerations cannot be applied to the amounts recorded for deferred income taxes.

Flying J Acquisition

On January 29, 2003, the Company acquired oil and gas properties and other assets and liabilities from Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. (collectively, "Flying J"). As consideration for the properties, St. Mary issued 3,380,818 restricted shares of its common stock to Flying J. In addition, St. Mary made a non-recourse loan to Flying J of $71.6 million at the one-year LIBOR plus 2 percent for up to a 39-month period. The loan was funded using cash on hand and borrowing under the credit facility in place at the time of the transaction. This loan was secured by a pledge of the shares of common stock issued to Flying J, with the final nine months of interest on that loan to be with recourse to Flying J. St. Mary also entered into a put and call option agreement with Flying J whereby during the 39-month loan period Flying J could elect to put their shares of St. Mary common stock to the Company for $71.6 million plus accrued interest on the loan during the first thirty months of the loan period, and St. Mary could elect to call the shares for $97.4 million, with the proceeds from the exercise of either the put option or the call option to be applied to the repayment of the loan plus accrued and unpaid interest. The shares issued were restricted for a period of two years, and Flying J was prohibited from selling the shares during that period. If neither Flying J nor St. Mary exercised their respective option rights, the loan plus accrued interest was to be repaid prior to the release of the security interest in the shares.

For financial reporting purposes, the effect of the above arrangements is that the Company acquired oil and gas properties and other assets and liabilities in exchange for $71.6 million of cash plus a net option to Flying J valued at $995,000 resulting in a total valuation of $72.6 million. The allocation of the purchase price for the net assets acquired was $72.4 million of proved reserves and unproved acreage, $445,000 of other assets, a $1.9 million asset retirement liability, a $2.0 million hedge liability, and $3.7 million in net cash received for purchase price adjustments. The acquisition was accounted for using the purchase method of accounting. Operating results from the acquired properties have been included in the consolidated statements of operations only from the date of closing.

The shares of common stock that were issued in this transaction were recorded as temporary equity since they were subject to the put option whereby the Company could have been required to repurchase these shares. The shares of common stock were considered outstanding for basic and diluted earnings per share calculations. The loan arising from this transaction was considered a contra-temporary equity item on the 2003 consolidated balance sheet, as opposed to an asset, since the loan was non-recourse to Flying J except with respect to interest accrued after the first thirty months and was secured by the restricted common stock issued as part of this transaction. Interest was not accrued for financial reporting purposes because of the non-recourse nature of the note.

As described more fully in Note 11 - Repurchase of St. Mary Common Stock, the Company entered into a separately negotiated transaction in February 2004 with Flying J to repurchase the 3,380,818 restricted shares issued in the acquisition.

Sales of Properties

Throughout 2004 the Company sold interests in certain non-core properties. The Company received cash proceeds of $2.8 million and recognized a gain of approximately $1.8 million from these sales. For property sales that occurred in the fourth quarter of 2004, the final proceeds and gain amounts are subject to the resolution of final post-closing adjustments and settlements. Throughout 2003 the Company sold interests in certain non-core properties primarily in Texas and Wyoming. The Company received $23.5 million in net proceeds and recognized a gain of approximately $7.3 million from these sales.

Note 4 - Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2004	2003	2002
	(In thousands)		
Current taxes:			
Federal	$ 21,143	$ 29,582	$ 719
State	1,389	2,656	569
Deferred taxes	31,217	23,692	13,731
Total income tax expense	$ 53,749	$ 55,930	$ 15,019

The above taxes from operations are net of alternative fuels credits (Internal Revenue Code Section 29) of $167,000 in 2002. Current federal tax expense does not reflect the tax benefit of $3.8 million in 2004, $1.2 million in 2003 and $719,000 in 2002 for deductions from stock option exercises.

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

	December 31,	
	2004	2003
	(In thousands)	
Deferred tax liabilities:		
Oil and gas properties	$ 146,427	$ 100,103
Interest on Convertible Notes	4,192	2,791
Amounts included in accumulated other comprehensive income	2,246	-
Derivative instruments and other	435	41
Total deferred tax liabilities	153,300	102,935
Deferred tax assets:		
Net Profits Plan liability	11,598	2,358
State tax net operating loss carryforward or carryback	2,981	2,094
Federal net operating loss carryforward or carryback	2,882	2,900
Stock compensation	1,590	-
State and federal income tax benefit	1,100	1,002
Deferred capital loss	758	1,840
Amounts included in accumulated other comprehensive income	1,033	9,222
Other, primarily employee benefits	969	2,286

Total deferred tax assets	22,911	21,702
Valuation allowance	(1,714)	(842)
Net deferred tax assets	21,197	20,860
Total net deferred tax liabilities	132,103	82,075
Less: current deferred income tax liabilities	(2,357)	-
Add: current deferred income tax assets	84	8,872
Non-current net deferred tax liabilities	$ 129,830	$ 90,947
Current federal refundable income tax	$ -	$ 454
Current federal income tax payable	$ 939	$ -
Current state refundable income tax	$ 139	$ -
Current state income tax payable	$ -	$ 1,334

At December 31, 2004, the Company had state net operating loss carryforwards of approximately $42.8 million and state tax credits of $93,000, which expire between 2005 and 2023. The Company's valuation allowance relates to those state net operating loss carryforwards and state tax credits that the Company anticipates will expire before they can be utilized. The Company has concluded that permanent items included in the calculation of income tax for certain states may impact its ability to deduct net operating losses incurred in those states and has adjusted its valuation allowances accordingly.

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

	For the Years Ended December 31,		
	2004	2003	2002
		(In thousands)	
Federal statutory taxes	$ 51,180	$ 49,668	$ 14,477
Increase (reduction) in taxes resulting from:			
State taxes (net of federal benefit)	2,586	5,812	2,092
Statutory depletion	(224)	(224)	(218)
Alternative fuel credits (Section 29)	-	-	(167)
Change in valuation allowance	872	115	(1,202)
Other	(665)	559	37
Income tax expense from operations	$ 53,749	$ 55,930	$ 15,019

Acquisitions, drilling and basis differentials impacting the prices received for crude oil and natural gas impact the apportionment of taxable income to the states where the Company owns properties. As these factors change, the Company's state income tax rate changes. This change applied to the Company's total temporary differences will impact the total income tax reported in the current year and is reflected in state taxes in the table above. These impacts are evaluated upon completion of the prior year income tax return, after significant acquisitions are closed and at the end of the year.

Note 5 - Long-term Debt

Revolving Credit Facility

The Company has a revolving credit facility with a group of banks. The credit facility specifies a maximum loan amount of $300.0 million and has a maturity date of January 27, 2006. Borrowings under the facility are secured by a pledge of collateral that includes the majority of the Company's oil and gas properties and the common stock of the material subsidiaries of the Company. The bank group authorized a borrowing base of $325.0 million in October 2004 under its normal semi-annual redetermination. The borrowing base redetermination process considers the value of St. Mary's oil and gas properties, using oil and gas pricing criteria specified by the bank syndicate, and other assets as determined by the bank syndicate. Although the borrowing base exceeds the maximum loan amount, the most that the Company could borrow under the facility is limited to the maximum loan amount. The Company has elected an aggregate commitment amount of $150.0 million. The Company must comply with certain financial and non-financial covenants including the limitation of our annual dividend rate to no more than $0.20 per share. The Company is in compliance with all of the covenants. Interest and commitment fees are accrued based on the borrowing base utilization percentage table below. Eurodollar loans accrue interest at LIBOR plus the applicable margin from the utilization table, and Alternative Base Rate (ABR) loans accrue interest at Prime plus the applicable margin from the utilization table. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations.

Borrowing base utilization percentage	<50%	=>50%<75%	=>75%<90%	>90%

Eurodollar Loans	1.25%	1.50%	1.75%	2.00%
ABR Loans	0.00%	0.25%	0.50%	0.75%
Commitment Fee Rate	0.30%	0.38%	0.38%	0.50%

At December 31, 2004, the Company's borrowing base utilization percentage as defined under the credit agreement was 24.7 percent. The Company had $10.0 million in ABR borrowings and $27.0 million in LIBOR based loans outstanding under its revolving credit agreement as of December 31, 2004. As of

February 15, 2005, the Company had an outstanding ABR balance of $2 million and an outstanding balance of $44 million under its LIBOR alternative.

5.75% Senior Convertible Notes Due 2022

As of December 31, 2004, the Company also had $100.0 million in outstanding borrowings under the Convertible Notes. The Convertible Notes provide for the payment of contingent interest of up to an additional 0.5 percent during six-month interest periods based on the Convertible Note market price before the beginning of the particular six-month period. Under that provision, interest was accrued at a total rate of 6.25 percent for 2004. Based on the trading price of the Convertible Notes over the determination period, the Company will be subject to the contingent interest payments for the period from September 16, 2004, to March 15, 2005.

The Convertible Notes are general unsecured obligations and rank on parity in right of payment with all existing and future unsecured senior indebtedness and other general unsecured obligations. They are senior in right of payment to all future subordinated indebtedness. The Convertible 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 Convertible Notes with cash in whole or in part at a repurchase price of 100 percent of the principal amount plus accrued and unpaid interest (including contingent interest) beginning on March 20, 2007. The note holders have the option of requiring the Company to repurchase the Convertible Notes for cash at 100 percent of the principal amount plus accrued and unpaid interest (including contingent interest) upon (1) a change in control of St. Mary or (2) on March 20, 2007, March 15, 2012, and March 15, 2017. If the note holders require repurchase on March 20, 2007, the Company may elect to pay the repurchase price with cash, shares of its common stock valued at a discount at the time of repurchase, or any combination of cash and its discounted common stock. The shares of common stock used in any repurchase will be discounted at 95 percent of market price if 33 percent or less of the repurchase price is in shares of our common stock; otherwise, the stock will be discounted at 93 percent of market value. St. Mary is not restricted from paying dividends, incurring debt, or issuing or repurchasing its securities under the indenture for the Convertible Notes. There are no financial covenants in the indenture. Based on the market price of the Convertible Notes, the estimated fair value of the Convertible Notes was approximately $171.8 million as of December 31, 2004, and approximately $135.3 million as of December 31, 2003.

Weighted-Average Interest Rate Paid and Capitalized Interest

The weighted-average interest rate paid in 2004 was 7.1 percent including commitment fees paid on the unused portion of the credit facility aggregate commitment, amortization of deferred financing costs, amortization of the contingent interest embedded derivative and the effect of interest rate swaps. The impact of these items over a lower average outstanding loan balance results in a higher weighted-average interest rate despite lower LIBOR interest rates than in previous periods. The company capitalized interest costs of $1.4 million, $780,000, and $427,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

Note 6 - Commitments and Contingencies

The Company leases office space under various operating leases with terms extending as far as May 31, 2012. Rent expense, net of sublease income, was $1.5 million, $1.3 million, and $1.1 million in 2004, 2003 and 2002, respectively. The Company also leases office equipment under various operating leases. The Company has a non-cancelable sublease of approximately $1.3 million through 2012. The annual minimum lease payments for the next five years and thereafter are presented below:

Years Ending December 31,	(In thousands)
2005	$ 2,440
2006	1,814
2007	1,306
2008	1,193
2009	1,065
Thereafter	2,876
Total	$ 10,694

The Company is subject to litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company. Management believes it has sufficiently provided for such items in the consolidated balance sheets.

Note 7 - Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan that normally allows participants to receive up to 50 percent, but in special situations to receive up to 100 percent 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 $2.0 million for cash bonuses in 2004 that will be paid in 2005, and $5.4 million for cash bonuses in 2003 that were paid in 2004.

Net Profits Plan

Under the Company's Net Profits Plan, oil and gas wells that are completed or acquired during a year are designated within a specific pool. Key employees designated as participants by the Company's Compensation Committee of the Board of Directors and employed by the Company on the last day of that year vest and become entitled to bonus payments after the Company has received net cash flows returning 100 percent of all costs and expenses associated with that pool. Thereafter, 10 percent of future cash flows generated by the pool are allocated among the participants and distributed at least annually. The percentage of cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs and expenses for the pool, including payments made under the Net Profits Plan at the 10 percent level.

Expense related to current distributions made under the Net Profits Plan in 2004, 2003 and 2002 were $8.0 million, $8.9 million, and $4.8 million, respectively. These amounts relate to current realized results from oil and gas operations in the respective periods.

The Company records the estimated liability for the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The following table presents the changes in the estimated liability attributable to the Net Profits Plan:

	As of December 31,	
	2004	2003
	(In thousands)	
Beginning liability for Net Profits Plan	$ 6,163	$ 846
Change in liability for accretion and change in estimates	32,410	14,235
Reduction in liability for cash payments made or accrued and recognized as compensation expense under the Net Profits Plan	(8,012)	(8,918)
Ending liability for Net Profits Plan	$ 30,561	$ 6,163

The Company records the expense associated with changes in the present value of estimated future payments under the Net Profits Plan as a separate item in the consolidated statements of operations. The change in the estimated liability is recorded as an increase or decrease to expense in the current period. The amount recorded as an increase or decrease to expense associated with the change in the estimated liability is not allocated to general and administrative costs or exploration costs because the adjustment of the liability is associated with the future net cash flows from oil and gas properties in the respective pools rather than current period performance. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items:

	For the Years Ended December 31,		
	2004	2003	2002
		(In thousands)	
General and administrative expense	$ 14,609	$ 3,982	$ 616
Exploration expense	9,789	1,335	230
Total	$ 24,398	$ 5,317	$ 846

401(k) Plan

The Company has a defined contribution pension plan (the "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 60 percent of their base salaries. The Company matches each employee's contributions up to 6 percent of the employee's base salary and may also make additional contributions at its discretion. The Company's contributions to the 401(k) Plan were $834,000, $746,000, and $621,000 for the years ended December 31, 2004, 2003, and 2002, respectively. No discretionary contributions were made by the Company to the 401(k) Plan in any of these three years.

Employee Stock Purchase Plan

Under the St. Mary Land & Exploration Company Employee Stock Purchase Plan ("the ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP are restricted for a period of 18 months from the date issued. The ESPP 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 ESPP. Shares issued under the ESPP totaled 13,874 in 2004, 16,994 in 2003, and 18,217 in 2002. Total proceeds to the Company for the issuance of these shares were $375,000 in 2004, $375,000 in 2003, and $344,000 in 2002. The Company recorded compensation expense of $21,000 in 2002 due to nonqualified dispositions of stock acquired by employees under the ESPP. No compensation expense has been recorded under the ESPP after 2002 since all shares issued under the ESPP after July 1, 2001 were issued as restricted shares and are not subject to disqualified disposition.

Stock Option Plans

The Company has a Stock Option Plan and an 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. There are 5,600,000 shares of the Company's common stock reserved for issuance under the Option Plans. This number is reduced to the extent that restricted stock or restricted stock units are granted under the Restricted Stock Plan. 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. There were 869,862 shares available for grant under the Option Plans (including the Restricted Stock Plan, as described later) as of December 31, 2004.

A summary of activity associated with the Company's Option Plans during the last three years follows:

	For the Years Ended December 31,					
	2004		2003		2002	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding, start of year	3,525,128	$ 23.10	3,061,566	$ 21.34	2,151,675	$ 19.42
Granted	58,678	37.79	858,431	26.70	1,109,541	23.55
Exercised	(699,526)	20.06	(245,019)	12.88	(177,085)	11.44
Forfeited	(58,605)	24.99	(149,850)	24.00	(22,565)	25.08
Outstanding, end of year	2,825,675	24.12	3,525,128	23.10	3,061,566	21.34
Exercisable, end of year	2,220,681	23.51	2,441,246	22.36	1,944,382	19.79
Weighted-average fair value of options granted granted during the year	$ 16.87		$ 12.28		$ 10.77	

A summary of additional information related to options outstanding as of December 31, 2004, 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 - $ 12.52	389,204	4.4 years	$ 11.50	389,204	$ 11.50
12.53 - 16.69	120,077	6.4 years	15.82	120,077	15.82
16.70 - 20.87	47,209	3.0 years	17.50	47,209	17.50
20.88 - 25.04	1,000,032	7.5 years	23.22	757,885	23.10
25.05 - 29.21	733,671	8.7 years	26.73	413,354	26.65

29.22 - 33.39	482,530	6.0 years	33.31	482,530	33.31
33.40 - 37.56	18,750	9.2 years	33.43	1,875	33.43
37.57 - 41.74	34,202	10 years	41.74	8,547	41.74
Total	2,825,675	7.0 years	24.12	2,220,681	23.51

SFAS No. 123 establishes a fair value method of accounting for stock-based compensation plans through either recognition or disclosure. The Company accounts for stock-based compensation under the intrinsic value method pursuant to 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 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. This pro forma information is prominently disclosed in Note 1-Summary of Significant Accounting Policies.

The fair value of options is measured at the date of grant using the Black-Scholes option-pricing model. The fair values of options granted were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,		
	2004	2003	2002
Risk free interest rate:			
Stock options	4.1%	3.6%	3.8%
Employee stock purchase plan	3.1%	3.7%	3.5%
Dividend yield:			
Stock options	0.3%	0.4%	0.4%
Employee stock purchase plan	0.3%	0.4%	0.4%
Volatility factor of the expected market price of the Company's common stock:			
Stock options	35.9%	39.9%	48.0%
Employee stock purchase plan	23.8%	20.2%	30.1%
Expected life of the options (in years)			
Stock options	9.0	7.0	5.9
Employee stock purchase plan	0.5	0.5	0.5

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. The Company's 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 valuations afforded by the existing models are different from the value that the options would realize if traded in the market.

Restricted Stock Plan

In May 2004 the Restricted Stock Plan was approved by the Company's stockholders, establishing a long-term incentive program whereby grants of restricted stock or restricted stock units may be awarded to eligible employees, consultants, and members of the Board of Directors. Restrictions and vesting periods for the awards are determined at the discretion of the Board of Directors and are set forth in the award agreements. The total number of shares of the Company's common stock reserved for issuance under the Restricted Stock Plan is 5,600,000. This number is reduced to the extent that stock options are granted under the Company's Option Plans.

St. Mary made grants of 232,861 RSUs in June 2004. The total expense associated with these grants was $8.3 million as measured on the date of the grant and has been reduced by $178,000 for forfeitures as of December 31, 2004. The total measured expense was initially recorded as deferred stock-based compensation and is being charged to compensation expense based on the vesting schedule. The RSU grants vest 25 percent immediately upon issuance and 25 percent on each of the first three anniversary dates. The vested shares underlying the RSU grants will be issued on the third anniversary of the grants, at which time the shares carry no further restrictions. As of December 31, 2004, there were 169,616 unvested RSUs, which included the total of the 2004 grants less the vested portion of the grants and units forfeited due to employee terminations prior to vesting. Compensation expense for the year ended December 31, 2004, related to the 2004 grants totaled $3.1 million. In addition, the Company recorded $1.1 million of compensation expense for the year ended December 31, 2004, related to the expected 25 percent immediate vesting of the estimated 2005 RSU grants.

Non -Employee Director Stock Compensation Plan

In May 2003, stockholders approved a Non-Employee Director Stock Compensation Plan to authorize the issuance of up to 30,000 shares of St. Mary common stock to non-employee directors as part of their compensation over an anticipated period of up to five years. The purpose of the plan is to attract, retain, and motivate non-employee directors. As of December 31, 2004, 12,600 shares have been issued under this plan.

Note 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").

Obligations and Funded Status

	For the Years Ended December 31,		
	2004	2003	2002
	(In thousands)		
Change in benefit obligations:			
Projected benefit obligation at beginning of year	$ 8,048	$ 6,330	$ 5,098
Service cost	1,139	963	442
Interest cost	489	428	358
Amendments	-	-	(46)
Actuarial loss	1,236	620	503
Benefits paid	(738)	(293)	(25)
Projected benefit obligation at end of year	$ 10,174	$ 8,048	$ 6,330
Change in plan assets:			
Fair value of plan assets at beginning of year	$ 3,694	$ 2,478	$ 2,042
Actual return on plan assets	434	608	(255)
Employer contribution	1,285	901	716
Benefits paid	(738)	(293)	(25)
Fair value of plan assets at end of year	$ 4,675	$ 3,694	$ 2,478
Funded status:	$ (5,499)	$ (4,354)	$ (3,758)
Unrecognized net loss	3,754	2,874	2,925
Unrecognized prior service cost	-	(15)	(41)
Accrued benefit cost	$ (1,745)	$ (1,495)	$ (874)

Amounts Recognized in the Consolidated Balance Sheets

	As of December 31,	
	2004	2003
	(In thousands)	
Accrued benefit cost	$ 1,745	$ 1,495
Accumulated other comprehensive income	746	914
Net amount recognized	$ 2,491	$ 2,409

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets

	As of December 31,	
	2004	2003
	(In thousands)	
Projected benefit obligation	$ 10,174	$ 8,048
Accumulated benefit obligation	$ 7,143	$ 6,058
Fair value of plan assets	$ 4,675	$ 3,694

The Company's accumulated benefit obligation for the Qualified Pension Plan was $5.9 million at December 31, 2004, and $4.8 million at December 31, 2003. The accumulated benefit obligation exceeds plan assets by $1.2 million. The tax-adjusted liability of $463,000 was recorded in other comprehensive income at December 31, 2004.

The Company's accumulated benefit obligation for the Nonqualified Pension Plan was $1.2 million at December 31, 2004, and $1.2 million at December 31, 2003. There are no plan assets in the Nonqualified Pension Plan due to the nature of the plan.

Components of Net Periodic Benefit Cost

For the Years Ended December 31,

	2004	2003	2002
		(In thousands)	
Components of net periodic benefit cost:			
Service cost	$ 1,139	$ 963	$ 442
Interest cost	489	428	358
Expected return on plan assets	(295)	(172)	(146)
Amortization of prior service cost	(16)	(25)	(25)
Amortization of net actuarial loss	218	329	211
Net periodic benefit cost	$ 1,535	$ 1,523	$ 840

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 percent 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.

Additional Information

The minimum liability included in other accumulated comprehensive income, net of taxes, decreased by $101,000 and $197,000 for the years ended December 31, 2004 and 2003, respectively, and increased by $761,000 for the year ended December 31, 2002.

Assumptions

Weighted-average assumptions to measure the Company's projected benefit obligation and net periodic benefit cost are as follows:

	As of December 31,	
	2004	2003
Projected benefit obligation		
Discount rate	5.75%	6.25%
Expected return on plan assets	8.00%	8.00%
Rate of compensation increase	4.00%	3.50%
Net periodic benefit cost		
Discount rate	6.25%	6.50%
Expected return on plan assets	8.00%	8.00%
Rate of compensation increase	3.50%	3.75%

Plan Assets

The Company's weighted-average asset allocation for the Qualified Plan is as follows:

		As of December 31,	
Asset Category	Target 2005	2004	2003
Equity securities	60.0%	63.0%	61.4%
Debt securities	40.0%	34.7%	38.0%
Other	0%	2.3%	0.6%
Total	100.0%	100.0%	100.0%

Equity securities do not include any shares of the Company's common stock for any period presented. There is no asset allocation for the Nonqualified Pension Plan since that plan does not have its own assets. An expected return on plan assets of eight percent was used to calculate the Company's obligation under the Qualified Plan. Factors considered in determining the expected return include the 60 percent equity and 40 percent debt securities mix of investment for plan assets and the long-term historical rate of return provided by the equity and debt securities markets. The estimated rate of return on plan assets was 11.7 percent for 2004 and 24.6 percent for 2003. The difference in investment income using the projected rate of return compared to the actual rates of return for the past two years was not material and will not have a material effect on the statements of operation or on cash flows from operating activities in future years.

Contributions

The Company contributed $1.3 million, $901,000, and $716,000 to the pension plans in the years ended December 31, 2004, 2003, and 2002, respectively. St. Mary expects to contribute approximately $1.1 million to the pension plans in 2005.

Benefit Payments

The Company made actual benefit payments of $738,000, $293,000, and

$25,000 in the years ended December 31, 2004, 2003 and 2002, respectively. Expected benefit payments over the next ten years follows:

Years Ended December 31,	(in thousands)
2005	$ 368
2006	$ 371
2007	$ 469
2008	$ 597
2009	$ 837
2010 through 2014	$ 11,752

Note 9 - Asset Retirement Obligations

As of January 1, 2003, the Company adopted the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and a corresponding increase to the carrying value of the related long-lived asset is recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties on the consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes accretion expense in connection with the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Prior to the adoption of SFAS No. 143, the Company had recognized an abandonment liability for its offshore wells. These offshore liabilities were reversed upon adoption of SFAS No. 143, and the methodology described above was used to determine the liability associated with abandoning all wells, including those offshore.

The estimated liability is based on historical experience in abandoning wells, estimated economic lives, external estimates as to the cost to abandon the wells in the future and federal, and state regulatory requirements. The liability is discounted using a credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company's abandonment liabilities range from 6.50 percent to 7.25 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

Upon adoption of SFAS No. 143, the Company recorded a discounted liability of $21.4 million, reversed the existing offshore abandonment liability of $9.1 million, increased property and equipment by $12.8 million, decreased accumulated DD&A by $8.3 million and recognized a one-time cumulative effect gain of $5.4 million (net of deferred tax benefit of $3.4 million).

A reconciliation of the Company's asset retirement obligation liability is as follows:

	As of December 31,	
	2004	2003
	(In thousands)	
Beginning asset retirement obligation	$ 25,485	$ -
Liability from SFAS 143 adoption	-	21,403
Liabilities incurred	7,187	4,395
Liabilities settled	(620)	(3,169)
Accretion expense	1,984	1,719
Revision to estimated cash flows	6,875	1,137
Ending asset retirement obligation	$ 40,911	$ 25,485

The following tables illustrate the effect on the asset retirement obligation liability, net income and earnings per share if the Company had adopted the provisions of SFAS No. 143 on January 1, 2002. The pro forma amounts are calculated using current information, assumptions and interest rates as of January 1, 2003 (in thousands, except per share amounts).

	As of December 31,
	2002
Asset retirement obligation liability	$ 21,829

	Year Ended December 31,
	2002

Net income		
As reported	$	27,560
Pro forma	$	26,622
Basic earnings per share		
As reported	$	0.99
Pro forma	$	0.96
Diluted earnings per share		
As reported	$	0.97
Pro forma	$	0.94

Note 10 - Derivative Financial Instruments

The Company realized a net loss of $50.6 million from its derivative contracts for the year ended December 31, 2004, a net loss of $22.7 million for the year ended December 31, 2003, and a net gain of $953,000 for the year ended December 31, 2002.

The following table summarizes derivative instrument gain (loss) activity (in thousands):

	For the Years Ended December 31,		
	2004	2003	2002
Derivative contract settlements included in oil and gas hedge loss	$ (50,299)	$ (22,439)	$ (2,235)
Ineffective portion of hedges qualifying for hedge accounting included in derivative gain (loss)	113	(246)	(32)
Non-qualified derivative contracts included in derivative gain (loss)	(373)	(64)	3,220
Total gain (loss)	$ (50,559)	$ (22,749)	$ 953

Oil and Gas Commodity Hedges

The Company has in place derivative contracts for the sale of oil and natural gas. The Company attempts to qualify these instruments as cash flow hedges for accounting purposes. The table below describes the volumes and average contract prices of hedges currently in place. The Company's oil and natural gas derivative contracts include swap and collar arrangements. Gas contracts are indexed to a variety of regional indexes, and the oil contracts are NYMEX based.

Swaps	Gas (per MMBtu)			Oil (per Bbl)		
Contract Period	Volumes		Weighted-Average Contract Price (Regional Index)	Volumes		Weighted-Average Contract Price (NYMEX)
2005						
Quarter Ending:						
March 31,	2,297,800	$	7.16	242,452	$	40.19
June 30,	2,026,600	$	6.16	184,214	$	42.56
September 30,	1,605,000	$	6.24	188,980	$	41.61
December 31,	1,590,000	$	6.54	138,770	$	40.80
Total 2005	7,519,400	$	6.56	754,416	$	41.24
2006						
Quarter Ending:						
March 31,	720,000	$	6.49	103,366	$	38.93
June 30,	710,000	$	5.51	99,976	$	38.15
September 30,	690,000	$	5.49	100,372	$	37.47
December 31,	270,000	$	5.55	77,686	$	36.42
Total 2006	2,390,000	$	5.80	381,400	$	37.83
2007						
Quarter Ending:						
March 31,	-	$	-	63,410	$	35.63
June 30,	-	$	-	61,072	$	35.35
September 30,	-	$	-	62,684	$	35.10
December 31,	-	$	-	60,620	$	34.79
Total 2007	-	$	-	247,786	$	35.22
All Contracts	9,909,400	$	6.38	1,383,602	$	39.22

Collars	Gas (per MMBtu)			
Contract Period	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Volumes	Index
2005				
Quarter Ending:				
March 31,	$ 6.62	$ 8.08	540,000	IF ANR OK
June 30,	$ 5.73	$ 7.20	540,000	IF ANR OK
September 30,	$ 5.75	$ 7.30	415,000	IF ANR OK
December 31,	$ 6.00	$ 7.63	390,000	IF ANR OK
All Contracts	$ 6.05	$ 7.57	1,885,000	

The Company seeks to minimize basis risk and indexes its oil contracts to NYMEX prices and its gas contracts to various regional index prices associated with pipelines in proximity to the Company's areas of gas production. Swap natural gas volumes associated with specific Inside FERC ("IF") regional indexes are as follows:

Regional Index	MMBtu
IF ANR OK	4,679,400
IF Reliant N/S	2,920,000
IF PEPL	2,310,000
Total	9,909,400

Derivative gain (loss) in the consolidated statements of operations for the year ended December 31, 2004, and 2003, include a net gain of $113,000 and a net loss of $246,000 from ineffectiveness related to oil and natural gas derivative contracts, respectively. On December 31, 2004, the estimated fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net asset of $4.2 million. If prices remain unchanged from year end levels, the Company would reclassify this amount to oil and gas hedge gain included in operating revenue as the hedged production quantity is produced. As of December 31, 2004, the net amount of unrealized gain net of deferred income taxes to be reclassified from accumulated other comprehensive income to oil and gas production operating revenues in the next twelve months was $5.0 million. The Company anticipates that all original forecasted transactions will occur by the end of their originally specified periods.

Interest Rate Derivative Contracts

In October 2003 the Company entered into fixed-to-floating interest rate swaps for a total notional amount of $50.0 million through March 20, 2007. Under the swaps, St. Mary will be paid a fixed interest rate of 5.75 percent and will pay a variable interest rate of 235 basis points above the six-month LIBOR rate as determined on the semi-annual settlement date. The payment dates of the swaps match the interest payment dates of the Convertible Notes. The six-month LIBOR rate on December 31, 2004, was 2.78 percent. Realized gains included in interest expense on these swaps were $795,000 in 2004. Derivative gain (loss) in the consolidated statements of operations for the year ended December 31, 2004, and 2003, includes a $328,000 and $104,000 net loss, respectively, from mark-to-market adjustments for this derivative. The fair value of the swaps was a liability of $432,000 and $104,000 as of December 31, 2004, and 2003, respectively.

Included in the consolidated statements of operations in 2002 is a net realized gain of $3.6 million included in derivative gain. This gain was generated from the settlement of a fixed-to-floating interest rate swap contract entered into in March 2002 on $50.0 million of the Convertible Notes. This swap did not qualify for fair value hedge treatment under SFAS No. 133 and related pronouncements. This contract was closed out on December 3, 2002.

Convertible Note Derivative Instrument

The Company's Convertible Notes contain a provision for payment of contingent interest if certain conditions are met. Under SFAS No. 133 this provision is considered an embedded equity-related derivative that is not clearly and closely related to the fair value of an equity interest and therefore must be treated as a separate derivative instrument. The value of the derivative at issuance of the Convertible Notes in March 2002 was $474,000. This amount was recorded as a decrease to the Convertible Notes payable in the consolidated balance sheets. Of this amount, $95,000, $95,000 and $75,000 have been amortized through interest expense for the years ended December 31, 2004, 2003, and 2002, respectively. Derivative gain (loss) in the consolidated statements of operations for the years ended December 31, 2004, 2003, and 2002, includes a $45,000 net loss, a $40,000 net gain and a $341,000 net loss, respectively, from mark-to-market adjustments for this derivative. The fair value of this derivative at December 31, 2004 and 2003, was a liability of $820,000 and $775,000, respectively.

Note 11 - Repurchase of St. Mary Common Stock

Flying J Repurchase Transaction

On February 9, 2004, the Company repurchased from Flying J 3,380,818 restricted shares of St. Mary common stock for a total of $91.0 million. These shares were originally issued by St. Mary to Flying J on January 29, 2003, in connection with St. Mary's acquisition of oil and gas properties. In addition to issuing the shares in the acquisition, St. Mary loaned Flying J $71.6 million. Flying J used the proceeds to repay their outstanding loan balance to St. Mary of $71.6 million. Accrued interest, which was not recorded by the Company for financial reporting purposes due to the non-recourse nature of the loan, was forgiven. The net $19.4 million cash outlay was funded from the Company's existing cash balances and borrowings under its credit facility.

Stock Repurchase Program

In August 2004 the Company's Board of Directors approved an increase in the number of shares that may be repurchased under the original authorization approved in August of 1998 to 3,000,000 as of the effective date of the resolution. St. Mary had not made any repurchases under the program since 2001. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of St. Mary's existing credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow and borrowings under the credit facility. The stock repurchase program may be suspended or discontinued at any time. As of December 31, 2004, a total of 1,499,200 shares of the Company's common stock had been repurchased under the plan. The company repurchased 489,300 and -0- shares in 2004 and 2003, respectively. In September 2004 the Company retired from treasury the 489,300 shares repurchased in 2004 together with 740,100 shares repurchased in prior years.

Note 12 - 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. The 2004 and 2003 amounts include $14.1 million and $5.5 million, respectively, of capitalized costs associated with asset retirement obligations.

	For the Years Ended December 31,		
	2004	2003	2002
		(In thousands)	
Development costs	$ 190,829	$ 111,908	$ 74,376
Exploration	37,977	33,296	22,548
Acquisitions:			
Proved	69,054	73,989	85,559
Unproved	7,646	8,942	2,147
Leasing activity	7,877	7,480	8,128
Total	$ 313,383	$ 235,615	$ 192,758

Oil and Gas Reserve Quantities (Unaudited):

For all years presented the reserve information for greater than 80 percent of the PV-10 value was prepared by Ryder Scott Company L.P. and/or Netherland, Sewell and Associates, Inc. ("NSAI"). The Company engaged NSAI for the first time in 2004. St. Mary prepared the reserve estimates for the remainder of all properties. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established 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 that 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. All of the Company's proved reserves are located in the United States.

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

	2004		2003		2002	
	Oil or Condensate	Gas	Oil or Condensate	Gas	Oil or Condensate	Gas
	(MBbl)	(MMcf)	(MBbl)	(MMcf)	(MBbl)	(MMcf)
Developed and undeveloped:						
Beginning of year	47,787	307,024	36,119	274,172	23,669	241,231
Revisions of previous estimate	1,994	(21,885)	2,856	3,904	3,611	4,696
Discoveries and extensions	6,306	63,185	3,681	69,189	1,250	32,813
Purchases of minerals in place	5,773	17,635	11,952	41,335	10,578	38,118
Sales of reserves	(487)	(165)	(2,280)	(31,913)	(174)	(4,522)
Production	(4,799)	(46,598)	(4,541)	(49,663)	(2,815)	(38,164)
End of year (a)	56,574	319,196	47,787	307,024	36,119	274,172
Proved developed reserves:						
Beginning of year	43,693	264,140	33,580	228,973	20,679	205,637
End of year	47,992	272,295	43,693	264,140	33,580	228,973

For the Years Ended December 31,

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(a) At December 31, 2004, 2003, and 2002 amounts include approximately 480, 1,119, and 1,151 MMcf, respectively, representing the Company's net 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, quality and basis differentials, in effect at year-end to the year-end estimated quantities of oil and gas to be produced in the future. Each property the Company operates is also charged with field-level overhead in the estimated reserve calculation. Estimated future income taxes are computed using current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a 10 percent annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the proved oil and gas reserves in place at the end of the period, using year-end costs and assuming continuation of existing economic conditions, plus Company overhead incurred by the central administrative office attributable to operating activities.

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 value. 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, quality and basis differentials, were used in the calculation of the standardized measure:

	2004	2003	2002
Gas (per Mcf)	$ 5.80	$ 5.70	$ 4.21
Oil (per Bbl)	$ 40.06	$ 31.01	$ 29.31

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:

	As of December 31,		
	2004	2003	2002
		(In thousands)	
Future cash inflows	$ 4,118,188	$ 3,232,605	$ 2,238,513
Future production costs	(1,349,380)	(963,226)	(696,132)
Future development costs	(164,797)	(101,935)	(87,859)
Future income taxes	(827,368)	(735,947)	(429,618)
Future net cash flows	1,776,643	1,431,497	1,024,904
10 percent annual discount	(742,705)	(571,541)	(443,042)
Standardized measure of discounted future net cash flows	$ 1,033,938	$ 859,956	$ 581,862

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

	For the Years Ended December 31,		
	2004	2003	2002
		(In thousands)	
Standard measure, beginning of year	$ 859,956	$ 581,862	$ 281,877
Sales of oil and gas produced, net of production costs and hedging	(368,099)	(299,044)	(137,066)
Net changes in prices and production costs	166,826	168,661	298,079
Extensions, discoveries and other, net of production costs	279,763	226,181	92,227
Purchase of minerals in place	73,875	178,264	160,089
Development costs incurred during the year	46,156	22,763	23,802
Changes in estimated future development costs	(17,489)	11,175	4,265
Revisions of previous quantity estimates	(24,271)	45,551	49,892
Accretion of discount	125,175	78,869	34,749
Sales of reserves in place	(3,906)	(47,270)	(708)
Net change in income taxes	(75,389)	(211,381)	(177,335)
Changes in timing and other	(28,659)	104,325	(48,009)
Standardized measure, end of year	$ 1,033,938	$ 859,956	$ 581,862

Note 13 - Quarterly Financial Information (Unaudited)

The Company's quarterly financial information for fiscal 2004 and 2003 is as follows (in thousands, except per share amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2004				
Total revenue	$ 96,482	$ 102,151	$ 108,078	$ 126,388
Less: costs and expenses	60,603	65,566	71,575	83,440
Income from operations	$ 35,879	$ 36,585	$ 36,503	$ 42,948
Income before income taxes	$ 34,535	$ 35,262	$ 35,125	$ 41,306
Net income	$ 21,449	$ 21,836	$ 22,565	$ 26,629
Basic net income per common share	$ 0.72	$ 0.76	$ 0.79	$ 0.94
Diluted net income per common share	$ 0.66	$ 0.69	$ 0.71	$ 0.83
Dividends declared per common share	$ -	$ 0.05	$ 0.05	-
Year Ended December 31, 2003				
Total revenue	$ 101,155	$ 103,628	$ 90,935	$ 97,990
Less: costs and expenses	54,736	61,619	66,624	57,418
Income from operations	$ 46,419	$ 42,009	$ 24,311	$ 40,572
Income before income taxes and cumulative effect of accounting principle	$ 44,433	$ 39,986	$ 22,551	$ 39,100
Net income	$ 32,797	$ 24,317	$ 13,786	$ 24,675
Basic earnings per common share:				
Income before cumulative effect of change in accounting principle	$ 0.90	$ 0.77	$ 0.44	$ 0.78
Cumulative effect of change in accounting principle	0.18	-	-	-
Basic net income per common share	$ 1.08	$ 0.77	$ 0.44	$ 0.78
Diluted earnings per common share:				
Income before cumulative effect of change in accounting principle	$ 0.81	$ 0.71	$ 0.41	$ 0.72
Cumulative effect of change in accounting principle	0.16	-	-	-
Diluted net income per common share	$ 0.97	$ 0.71	$ 0.41	$ 0.72
Dividends declared per common share	$ -	$ 0.05	$ -	$ 0.05

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: February 25, 2005

By: /S/ MARK A HELLERSTEIN
Mark A. Hellerstein
Chairman of the Board of Directors, President and Chief Executive Officer

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Mark A. Hellerstein and David W. Honeyfield his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2004, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

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/ MARK A. HELLERSTEIN Mark A. Hellerstein	Chairman of the Board of Directors, President and Chief Executive Officer	February 25, 2005
/S/ DAVID W. HONEYFIELD David W. Honeyfield	Vice President-Finance, Secretary and Treasurer	February 25, 2005
/S/ GARRY A. WILKENING Garry A. Wilkening	Vice President-Administration and Controller	February 25, 2005

Signature	Title	Date
/S/BARBARA M. BAUMANN Barbara M. Baumann	Director	February 25, 2005
/S/ LARRY W. BICKLE Larry W. Bickle	Director	February 25, 2005
/S/ RONALD D. BOONE Ronald D. Boone	Director	February 25, 2005
/S/ THOMAS E. CONGDON Thomas E. Congdon	Director	February 25, 2005
/S/ WILLIAM J. GARDINER William J. Gardiner	Director	February 25, 2005
/S/ WILLIAM D. SULLIVAN William D. Sullivan	Director	February 25, 2005

/S/ JOHN M. SEIDL
- -----------------
John M. Seidl Director February 25, 2005

EXHIBIT 10.47

EXPLANATORY NOTE:

The following Attachment A to Form of Change of Control Executive Severance Agreement shall supersede the prior Attachment A previously filed on November 13, 2001 as Exhibit 10.1 (the "Exhibit") to the Quarterly Report on Form 10-Q by St. Mary Land & Exploration Company for the quarterly period ended September 30, 2001. The text of the Form of Change of Control Executive Severance Agreement preceding the prior Attachment A in the Exhibit is not changed hereby.

Attachment A
to
Form of
Change of Control Executive Severance Agreement

Executives with Change of Control Executive Severance Agreements:

All employees of St. Mary Land & Exploration Company who have an officer title of Vice President or an officer title which is senior to a Vice President.

Exhibit 10.48

SECOND AMENDMENT TO

ST. MARY LAND & EXPLORATION COMPANY

EMPLOYEE STOCK PURCHASE PLAN

This Second Amendment (the "Amendment") to the St. Mary Land & Exploration Company Employee Stock Purchase Plan (the "Plan") is adopted by the Board of Directors of St. Mary Land & Exploration Company on February 18, 2005.

Pursuant to Article XIII of the Plan, the Board of Directors may at any time and from time to time amend or modify the Plan, provided that such amendment or modification does not adversely affect any outstanding Option under the Plan. The Board of Directors hereby amends the Plan as follows:

1. Section 3.1 of the Plan shall be amended in its entirety to read as follows:

> 3.1 Initial Eligibility. Any Employee shall be eligible to participate in Offerings under the Plan which commence on or after the first Offering Commencement Date occurring after the Employee's commencement of employment with the Company or a Subsidiary Corporation.

2. This Amendment shall be effective with respect to all Offerings under the Plan commencing on or after January 1, 2005.

3. In all other respects, the Plan is republished and reaffirmed. Capitalized terms used but not defined herein shall have the meanings ascribed to such terms in the Plan.

This Second Amendment to the St. Mary Land & Exploration Company Employee Stock Purchase Plan was adopted by the Compensation Committee of the Board of Directors and approved by the Board of Directors of St. Mary Land & Exploration Company on February 18, 2005.

ST. MARY LAND & EXPLORATION COMPANY

By: /S/ MARK A. HELLERSTEIN

Mark A. Hellerstein
Chairman of the Board, President and
Chief Executive Officer

ST. MARY LAND & EXPLORATION COMPANY EXHIBIT 12.1

RATIO OF EARNINGS TO FIXED CHARGES

Years Ended December 31,				
2004	2003	2002	2001	2000
18.7%	17.3%	9.9%	69.4%	86.1%

The ratio of earnings to fixed charges has been computed by dividing earnings available for fixed charges (earnings from continuing operations before income taxes) by fixed charges (interest expense plus capitalized interest).

EXHIBIT 21.1

SUBSIDIARIES
OF
ST. MARY LAND & EXPLORATION COMPANY

A. Wholly-owned subsidiaries of St. Mary Land & Exploration Company, a Delaware corporation:

1. Nance Petroleum Corporation, a Montana corporation
2. St. Mary Energy Company, a Delaware corporation
3. Four Winds Marketing LLC, a Colorado limited liability company
4. Agate Petroleum, Inc., a Delaware corporation
5. SMT Texas LLC, a Colorado limited liability company

B. Other subsidiaries of St. Mary Land & Exploration Company:

1. Box Church Gas Gathering LLC, a Colorado limited liability company (58.6754%)
2. Trinity River Services LLC, a Texas limited liability company (25%)

C. Wholly-owned subsidiaries of Nance Petroleum Corporation:

1. NPC Inc., a Colorado corporation

D. Wholly-owned subsidiaries of St. Mary Energy Company:

1. SMEC Texas LLC, a Colorado limited liability company

E. Partnership interests held by St. Mary Land & Exploration Company:

1. Hilltop Investments, a Colorado general partnership (50%)
2. Parish Ventures, a Colorado general partnership (100%)

F. Partnership interests held by SMT Texas LLC:

1. St. Mary East Texas LP, a Texas limited partnership (99%) (the remaining 1% interest is held by St. Mary Land & Exploration Company)

G. Partnership interests held by SMEC Texas LLC:

1. St. Mary Energy Texas LP, a Texas limited partnership (99%) (the remaining 1% interest is held by St. Mary Energy Company)

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-35352, 333-88780, and 333-106438 on Form S-8 and Registration Statement Nos. 333-61850 and 333-58273 on Form S-8, and Registration Statement No. 333-88712 on Form S-3 of our reports dated February 21, 2005, relating to the financial statements (which report expresses an unqualified opinion and includes an explanatory paragraph for the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations"), of St. Mary Land & Exploration Company and to management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10-K of St. Mary Land & Exploration Company for the year ended December 31, 2004.

/S/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2005

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 of St. Mary Land & Exploration Company for the year ended December 31, 2004. We hereby further consent to the use of information contained in our reports, as of January 1, 2005, 2004 and 2003 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 Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-35352, 333-88780, and 333-106438 on Form S-8 and Registration Statement Nos. 033-61850 and 333-58273 on Form S-8, and Registration Statement No. 333-88712 on Form S-3.

Very truly yours,

/S/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.

Denver, Colorado,
February 23, 2005

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

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 of St. Mary Land and Exploration Company for the year ended December 31, 2004. We hereby further consent to the use of information contained in our reports, as of December 31, 2004 setting forth the estimates of revenues from St. Mary Land and Exploration Company's oil and gas reserves. We further consent to the incorporation by reference thereof into St. Mary Land and Exploration Company's Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-35352, 333-88780, and 333-106438 on Form S-8 and Registration Statement Nos. 033-61850 and 333-58273 on Form S-8, and Registration Statement No. 333-88712 on Form S-3.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /S/ G. LANCE BINDER

G. Lance Binder
Executive Vice President

Dallas, Texas
February 23, 2005

EXHIBIT 31.1

CERTIFICATION

I, Mark A. Hellerstein, certify that:

1. I have reviewed this annual report on Form 10-K of St. Mary Land & Exploration Company;

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

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

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

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

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

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

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

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

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

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

Date: February 24, 2005

/S/ MARK A. HELLERSTEIN

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Mark A. Hellerstein
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, David W. Honeyfield, certify that:

1. I have reviewed this annual report on Form 10-K of St. Mary Land & Exploration Company;

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

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

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

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

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

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

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

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

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

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

Date: February 24, 2005

/S/ DAVID W. HONEYFIELD

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David W. Honeyfield
Vice President - Finance

EXHIBIT 32.1

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

In connection with the Annual Report on Form 10-K of St. Mary Land & Exploration Company (the "Company") for the fiscal year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Mark A. Hellerstein, as Chief Executive Officer of the Company, and David W. Honeyfield, as Vice President - Finance of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

/S/ MARK A. HELLERSTEIN
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Mark A. Hellerstein
Chief Executive Officer
February 24, 2005

/S/ DAVID W. HONEYFIELD
- -----------------------
David W. Honeyfield
Vice President - Finance
(principal financial officer)
February 24, 2005