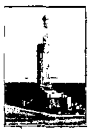
STONE
ENERGY

Focusing on the *Future*

2004 ANNUAL REPORT



Recent Highlights

- **Deepwater Initiative**—Entered into an agreement with Kerr-McGee for exploration in the Deepwater and Deep Shelf of the Gulf of Mexico.

- **GOM Acquisition**—Completed a preferential rights acquisition of additional working interest in South Timbalier Blocks 143, 164, 165, 166 and 171.

- **Debt Offering**—Issued $200 million of 6¾% Senior Subordinated Notes due 2014 through a private placement.

- **Rockies Acquisitions**—Completed exploration acreage acquisitions in the Williston Basin of North Dakota and Montana and a potential coal bed methane play in Utah.

- **New CEO**—The board of directors appointed David H. Welch as President, Chief Executive Officer and director of Stone effective April 1, 2004. Mr. Welch most recently had served as Senior Vice President of BP America, Inc. since 2003, and Vice President of BP, Inc. since 1999. D. Peter Canty retired as President and Chief Executive Officer in April but retained his seat on the board of directors.

- **2005 MMS Lease Sale**—Subject to MMS review and awarding procedures, Stone was apparent high bidder on eight new leases in the Gulf of Mexico, two of which are in the Deepwater.

Summary Financial and Reserve Data

(In thousands, except per share data)

Year Ended December 31,	**2004**	2003	2002	2001	2000
Oil and gas revenues	**$544,201**	$508,305	$337,495	$395,499	$381,938
Income (loss) from operations	**222,015**	226,190	105,012	(80,089)	201,013
Net income (loss)	**134,903**	134,470	55,399	(71,375)	126,457
Basic earnings (loss) per common share	**$5.07**	$5.10	$2.10	$(2.73)	$4.90
Diluted earnings (loss) per common share	**5.01**	5.07	2.09	(2.73)	4.80
Weighted average shares outstanding (basic)	**26,586**	26,353	26,326	26,111	25,804
Weighted average shares outstanding (diluted)	**26,901**	26,546	26,494	26,111	26,335
Net cash provided by operating activities	**$369,499**	$391,539	$222,921	$315,617	$302,082
Net cash used in investing activities	**(474,990)**	(341,908)	(216,600)	(656,847)	(258,637)
Net cash provided by (used in) financing activities	**112,648**	(60,140)	8,133	275,828	17,461
Total assets	**$1,820,895**	$1,434,277	$1,179,371	$1,101,783	$944,104
Long-term debt	**482,000**	370,000	431,000	426,000	148,000
Stockholders' equity	**854,334**	710,277	577,488	530,025	587,577
Oil and condensate reserves (MBbls)	**56,560**	59,162	52,019	55,391	33,625
Gas reserves (MMcf)	**485,590**	461,323	438,652	442,669	398,524
Total proved reserves (MMcfe)	**824,950**	816,295	750,766	775,015	600,274

Dear Fellow Stockholders,

This past year has been one of significant evolution for our Company. After ten years of faithfully following a strategy that drove Stone to become one of the premier independent Gulf Coast acquisition and exploitation players, it became apparent in late 2003 and early 2004 that it was time to update our platforms for growth. Technological advancements, shifting market dynamics, as well as the maturity of the conventional Gulf Coast Basin mandated a fresh approach to growth. On a worldwide stage, production declines in North America and other mature basins and dramatic demand growth, particularly in China and third world countries seeking to develop industrial infrastructures, created a higher-priced commodity environment in which a company such as ours can leverage growth through strategic diversification.

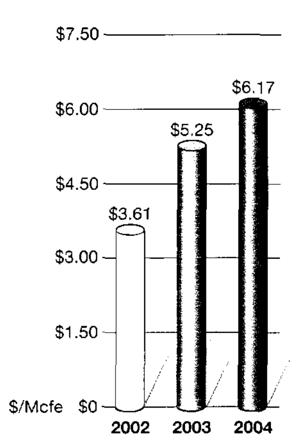
Stone experienced many positive and some negative results during 2004. On the positive side, our financial position is strong, we closed a number of advantageous transactions that added significantly to our acreage positions in the Rocky Mountains and in the Gulf of Mexico Shelf, Deep Shelf and Deepwater, and we improved our organizational capability to implement a more diversified approach to our business. On the negative side, Tropical Storm Bonnie and Hurricane Ivan forced evacuations, production shut-ins and delays in Gulf of Mexico drilling operations. Nonetheless, we did a great job marketing our products and capturing nearly all of the upside in 2004's strong commodity market for record level revenue.

When I came on board in early April 2004 as your new President and CEO, I devoted my time to familiarizing myself with all Stone people, properties and prospects and to the assessment of long-term growth opportunities. For the past decade, Stone has been more than 90% focused on the Conventional Gulf of Mexico Shelf, a mature basin that has been extremely lucrative but is increasingly characterized by high rates of decline and limited ability to sustain growth and provide robust shareholder value. Throughout 2004, we expanded our acreage positions in four primary basins—the Shelf, Deep Shelf and Deepwater of the Gulf of Mexico, and the Rocky Mountains—to diversify, extend our reserve life and take advantage of the strength of the oil and gas market. This effort will build new growth platforms for Stone that will leverage our core strengths and offer both the materiality and diversification needed to flatten out some of the peaks and valleys of the Conventional Gulf of Mexico Shelf's cyclicality.

We believe that entering the Gulf of Mexico Deepwater market now is opportune. In the next two to three years, more than 3,000 Deepwater leases could expire allowing us to participate in partnerships with current owners as they seek to drill their blocks before the acreage reverts back to the federal government. Our advantage is that we already possess the geoscience, engineering expertise and business know-how to analyze and partner on this Deepwater and Deep Shelf acreage. Indeed, in the March 2005 Mineral Management Service (MMS) lease sale, we were the apparent high bidder on eight prospects, two of which are Deepwater leases and the remaining six of which are Conventional and Deep Shelf prospects. And in October 2004, we announced an exploration agreement with Kerr-McGee covering interests in 30 leases in the Gulf of Mexico—a perfect entry vehicle for Stone into the higher potential Deepwater arena (see Deepwater discussion on pages 8–9).

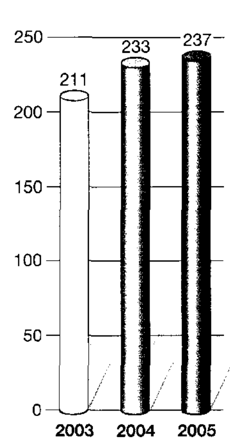
We also made significant changes to our holdings in the Rocky Mountains during 2004, first divesting certain non-core properties (amounting to approximately 1% of our total estimated proved reserves) on various regions of the Rockies. This allowed us to focus our efforts in larger, more material properties. Late in the fourth quarter, we announced the acquisition of leasehold rights to 27,000 net acres in the Uinta Basin in Utah (roughly 40 miles southeast of our Monument Butte field), where we will test for natural gas in 2005 with a three- to five-well program. At the close of the year, we also announced the acquisition of approximately 35,000 net acres in the Williston Basin of North Dakota and Montana. Much of this acreage is located within the Bakken formation fairway with attractive stacked oil pay potential, which will complement our Rocky Mountain gas business. Both of these acquisitions have since closed.

Average Realized Prices*



*Includes hedging.

Employee Growth



In the third quarter, our Gulf of Mexico Shelf operations were disrupted by tropical storms and hurricanes. Twice, we evacuated personnel from our platforms and rigs in the weather's path and shut in production. The more severe of the two events, Hurricane Ivan, significantly damaged a number of Mississippi Canyon and Main Pass area non-operated wells, platforms and downstream facilities including production pipelines. As a result of this damage, certain fields remained shut-in from mid-September through the remainder of the year. A majority of the production volumes were restored by the first quarter of 2005, with our Main Pass Block 288 and Mississippi Canyon Block 109 fields returning to production.

Growth places high demands on an organization. One of the first things I undertook upon coming to Stone was a thorough assessment of our management structure and our technical expertise. During the year, we simplified the organization to create better accountability and facilitate quicker resolution of operational and financial issues, strengthened our technical expertise in targeted growth areas, redeployed several key employees to improve execution, and streamlined a few internal policies and processes to place more focus on the fundamentals of finding and producing oil and gas. To further strengthen our efforts, we've welcomed new employees who bring many years of experience to help achieve our goals.

After years of service with Stone, my predecessor Pete Canty announced his retirement early in the year. As the primary designer of the acquisition and exploitation strategy that drove the Company's first decade of growth as a public company, Pete is to be lauded for his leadership. We are fortunate that he remains engaged with the Company as a director on our board. Another former president of the Company, Joe Klutts, retired from the board this year after more than 30 years service to Stone. Joe was a key player in the Company's transformation from a small private company to a public entity.

With our strengthened organization, we are elevating our deal exposure with more than 40 deals under active evaluation. These include active producing properties, exploratory plays and additional acquisitions in the Gulf of Mexico Shelf, Deep Shelf and Deepwater provinces, and large acreage acquisitions in the Rocky Mountains. Our new risk assessment team rigorously model exploration risks to properly evaluate potential investments. This is especially important in the Gulf of Mexico basins.

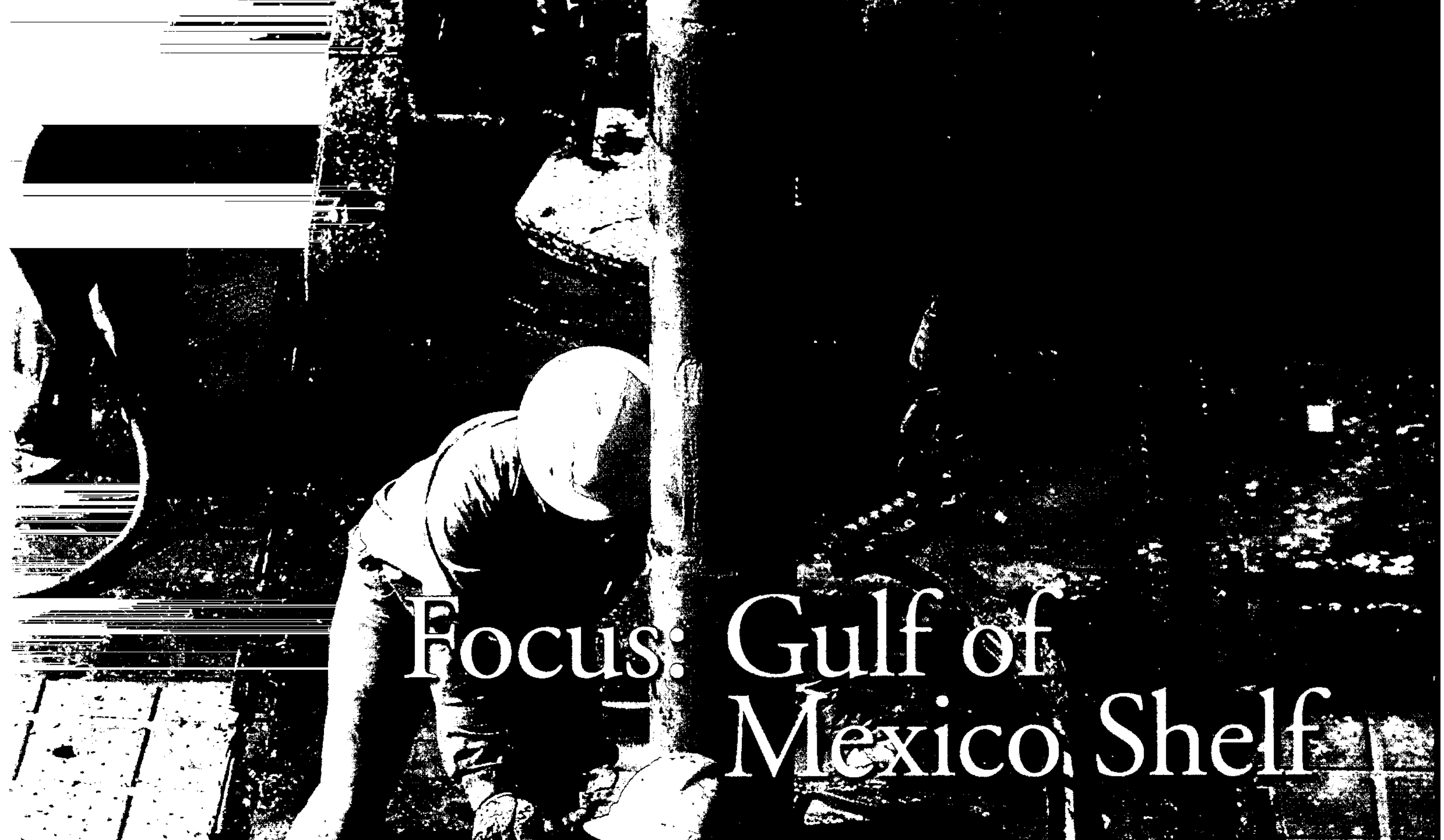
Going forward, we have allocated \$315 million to our 2005 capital expenditures budget to fund our exploration and development drilling program. In line with our broadened growth strategy, approximately 15% of the budget is allocated to Deepwater drilling in the Gulf of Mexico, 20% to the Rocky Mountains, 15% to Deep Shelf drilling in the Gulf and 50% to the Conventional Shelf.

I am confident that the changes we have made will expose us to robust opportunities and added meaningful shareholder returns in the years to come. Not long ago, I was asked what had impressed me the most in my first year at the helm of Stone Energy Corporation. My response was immediate. The most impressive thing about Stone is the people. They are highly skillful with great expertise and are deeply dedicated to the success of our enterprise. The quality of our people is excellent, and I'm proud to be a member of the team.

In closing, we'd like to express our gratitude for your continued confidence in Stone and pledge to deliver added shareholder value in the years ahead.

Sincerely,

David H. Welch
President and Chief Executive Officer



Focus: Gulf of Mexico Shelf

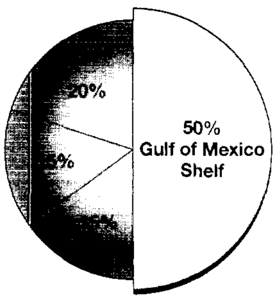
Historically Stone's primary operational focus, Gulf of Mexico Shelf properties' production generated 91% of the Company's total production throughout 2004. More than half of our 2004 capital expenditure budget was allocated to Shelf exploratory and development drilling, and we achieved a drilling success rate of 68%. In addition, with the year's heightened commodity prices, we realized unit prices of $39.40 per barrel of oil and $6.22 per Mcf of natural gas from our Shelf producing properties. Also, in order to more efficiently manage our overall commodity price risk, we began to utilize the zero-premium collar to hedge a portion of our expected 2005 Gulf Coast Basin oil and natural gas production. The zero-premium or "costless" collar requires the counterparty to pay if the price falls below the floor and requires payment to the counterparty if the price rises above the ceiling. We believe that these collars are currently the best instrument for our hedging strategy, which is to ensure a certain level of cash flow from our production necessary to fund our estimated capital spending. Our current 2005 collar contracts cover 70,000 MMBtus of daily natural gas production volumes with floor prices ranging from $4.00–$5.50 per MMBtu and ceiling prices ranging from $10.00–$13.50 per MMBtu. For 2005 oil production, we have hedged 8,000 barrels per day with a floor price of $28.00 per barrel and an average ceiling price of $52.83 per barrel. All of our collar contracts are with reputable financial institutions.

Production Disruption — As mentioned in the Shareholder Letter, the hurricane season in the Gulf of Mexico was particularly

The Conventional Shelf of the Gulf of Mexico is identified by a relatively shallow seafloor descending seaward at a slow gradient from the coastline to a water depth of approximately 650 feet. At this depth, the seafloor begins to rapidly drop off into the Deepwater region, creating a ledge or shelf-like formation. The Shelf includes all geological formations from the seafloor to a depth of 15,000 feet and has undergone exploration and production activity dating back to 1937.

□ 59 GCB Active Properties ▲ 54 GCB Primary Term Leases

Estimated 2005 Capital Spending

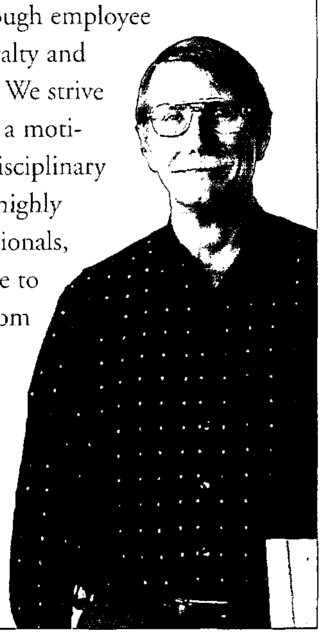


rough this past year. Of the two storms that directly affected our operations, Hurricane Ivan was the more serious, forcing personnel evacuation and production shut-in of all Gulf Coast Basin production, with the exception of Weeks Island. The hurricane's winds damaged many neighboring surface facilities, and the hurricane's surge created landslides or mudslides on the seafloor, toppling nearby platforms and severely damaging buried pipelines. In early 2005, production was restored to a majority of the properties impacted by the hurricane.

Acquisitions — Although we have stated that we are evolving into a more diversely focused exploitation and production company, we remain interested in overlooked or bypassed zones in mature reservoirs of the Conventional Shelf. We apply the latest geophysical interpretation tools to identify underdeveloped properties and the latest production techniques to increase production from these properties as we believe that significant reserves remain to be discovered and exploited. Using our extensive production history and data accumulated on the Shelf, our technical teams construct interpretations of the unique geology of each field to gain a better understanding of the potential location of previously untested or unexploited reserves. In addition, we are frequently able to combine exploratory and development targets in a single well to improve the chance of investment success.

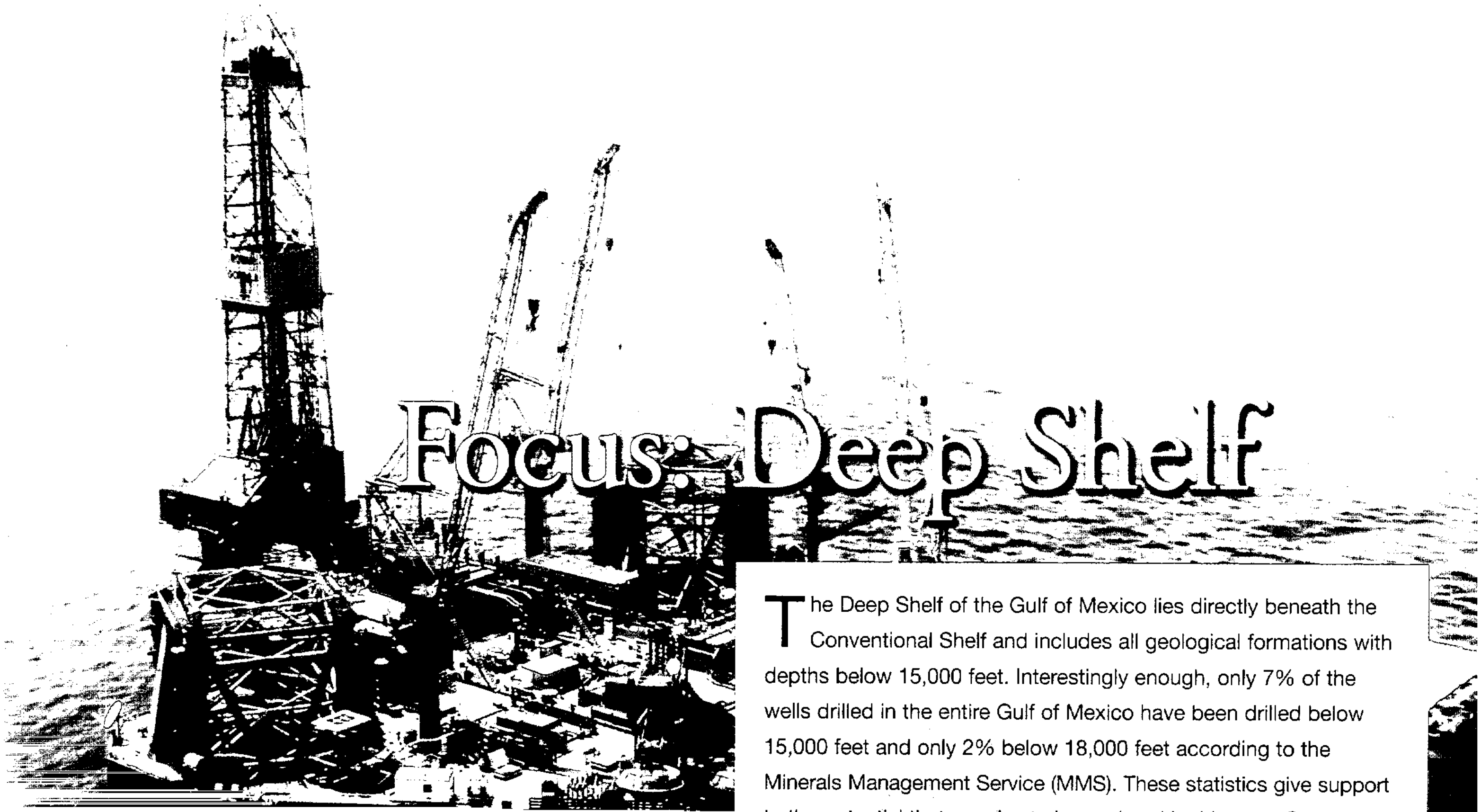
To that end, we completed a number of selective acquisitions of offshore Shelf blocks, which will provide us with ample opportunity for future exploitation and exploration.

"After 23 years, I've seen Stone grow from a small independent to a successful public company through employee allegiance, loyalty and commitment. We strive in developing a motivated multi-disciplinary workforce of highly skilled professionals, allowing Stone to stand apart from other companies in the industry."



Terry Delahoussaye, *Senior Production Foreman*

2005 Outlook — The Shelf of the Gulf, including onshore Louisiana, will continue to be our primary area of operation during 2005. A significant portion of our expected 2005 production growth will be generated by the success of production from our Shelf properties. With previously shut-in production now substantially restored, Stone is striving for total Company production growth of 8–14% during 2005. This production growth combined with our zero-premium collars as price protection should provide outstanding rates of return from our Shelf properties.

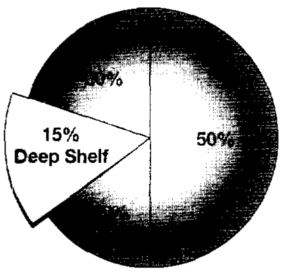


Focus: Deep Shelf

The Deep Shelf of the Gulf of Mexico lies directly beneath the Conventional Shelf and includes all geological formations with depths below 15,000 feet. Interestingly enough, only 7% of the wells drilled in the entire Gulf of Mexico have been drilled below 15,000 feet and only 2% below 18,000 feet according to the Minerals Management Service (MMS). These statistics give support to the potential that remains to be explored in this area. Our current property base contains multiple Deep Shelf exploration opportunities. The Deep Shelf couples higher risk with high potential prospects that already have infrastructure in place, which serves to shorten lead time to production. The exploration agreement with Kerr-McGee (covered in greater detail in the Gulf of Mexico Deepwater discussion on pages 8–9) in combination with our existing property base enables us to venture into Deep Shelf exploration activities. Our exploration venture with Kerr-McGee includes the drilling of two Deep Shelf prospects, both of which are expected to spud during the second quarter of 2005. Our preferential rights acquisition of the South Timbalier Block 172 field from Anadarko in the fourth quarter of 2004 also provides additional opportunity for Deep Shelf drilling. For 2005, we have allocated 15% of our

Using 3-dimensional and 4-component imaging and mapping technology allows us to identify potential prospects at increasingly further depths. The benefits of using advanced technology far exceeds the investment by allowing our technical staff the ability to integrate well, geophysical and engineering data. The result of this technology has been improved drilling success on deep targets.

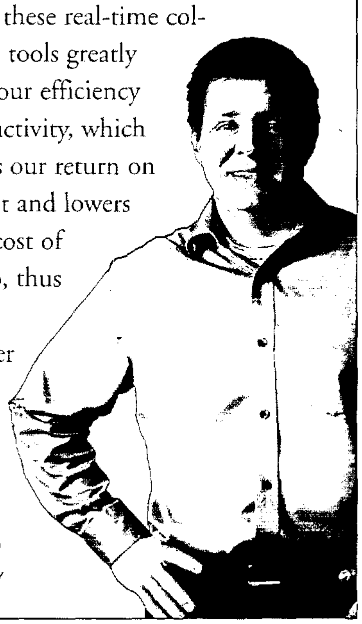
Estimated 2005 Capital Spending



expected capital spending to the Deep Shelf of the Gulf, which currently includes the drilling of seven Deep Shelf wells.

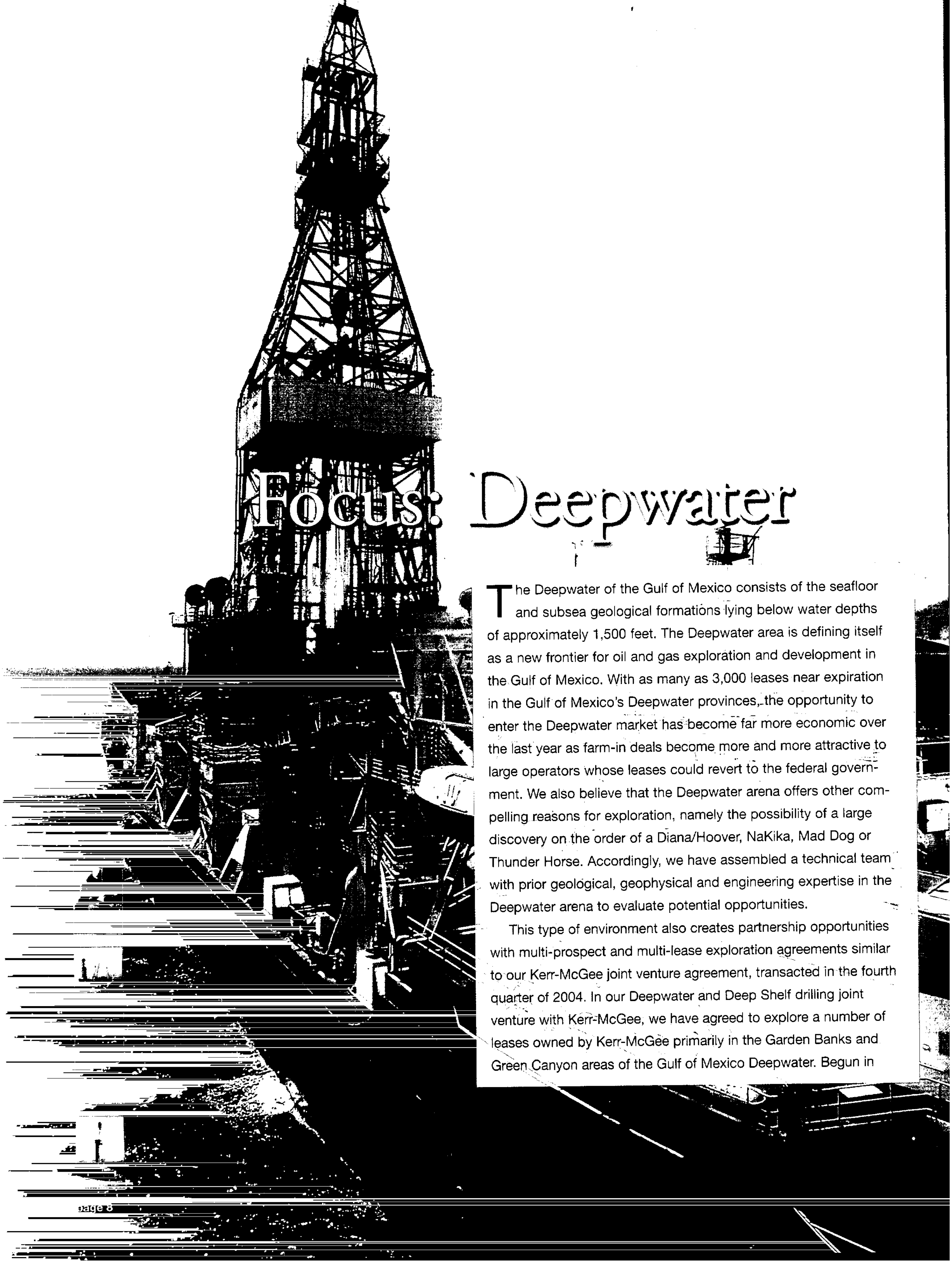
Drilling Update — The first of a multi-well program drilled from an existing platform has been completed at Viosca Knoll Block 817 with a discovery of the Antelope Prospect. First production is anticipated in the first quarter of 2005. We have a 100% working interest and a 70.3% net revenue interest in the wells drilled in this program. At South Marsh Island Block 192, the No. A-2 well was drilled from an existing platform to test the Magic Prospect and encountered commercial hydrocarbons. The facilities on the existing platform will be modified to accommodate added production, with first production anticipated in the fourth quarter of 2005. We have a 50% working interest and a 40.9% net revenue interest in these wells. Drilled earlier in the year, South Marsh Island Block 288 encountered 61 feet of gas pay in two sands below 15,000 feet. The well is currently producing approximately 3 million cubic feet of natural gas and 600 barrels of oil per day.

"By implementing leading-edge technologies, we provide our employees with seamless access to voice, video and data systems through a secure, scalable and reliable corporate network. Facilitating the use of these real-time collaboration tools greatly improves our efficiency and productivity, which maximizes our return on investment and lowers our total cost of ownership, thus increasing shareholder value."



Dave Kennedy,
Director of Information Technology

Acquisitions — In addition to the Deep Shelf opportunities generated through the South Timablier Block 172 field acquisition and exploration our agreement with Kerr-McGee, Stone has been active in acquiring leases in the Gulf of Mexico with Deep Shelf prospects through the MMS's annual lease sales. Over the past few years, Stone has amassed a number of prospects through these lease sales. With a bolstered inventory, our Deep Shelf drilling program can undertake an opportunity approach to prospect evaluation and exploration, which we expect will yield more favorable results.



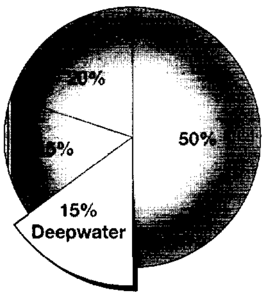
Focus: Deepwater

The Deepwater of the Gulf of Mexico consists of the seafloor and subsea geological formations lying below water depths of approximately 1,500 feet. The Deepwater area is defining itself as a new frontier for oil and gas exploration and development in the Gulf of Mexico. With as many as 3,000 leases near expiration in the Gulf of Mexico's Deepwater provinces, the opportunity to enter the Deepwater market has become far more economic over the last year as farm-in deals become more and more attractive to large operators whose leases could revert to the federal government. We also believe that the Deepwater arena offers other compelling reasons for exploration, namely the possibility of a large discovery on the order of a Diana/Hoover, NaKika, Mad Dog or Thunder Horse. Accordingly, we have assembled a technical team with prior geological, geophysical and engineering expertise in the Deepwater arena to evaluate potential opportunities.

This type of environment also creates partnership opportunities with multi-prospect and multi-lease exploration agreements similar to our Kerr-McGee joint venture agreement, transacted in the fourth quarter of 2004. In our Deepwater and Deep Shelf drilling joint venture with Kerr-McGee, we have agreed to explore a number of leases owned by Kerr-McGee primarily in the Garden Banks and Green Canyon areas of the Gulf of Mexico Deepwater. Begun in

According to the Minerals Management Service (MMS), more than 3,000 Deepwater leases are expiring over the next three years, providing an avenue of opportunity into this rapidly growing arena. The byproduct created by these lease expirations is an increase in opportunities to partner with others and the potential for acquiring additional blocks through lease sales.

Estimated 2005 Capital Spending



Gulf of Mexico Deepwater Lease Expirations 2005–2007

2004 with the drilling of the Essex and Fawkes Prospects, the program covers interests in 30 leases. Stone acquired the right to earn working interests from 16.67% to 50%, while Kerr-McGee remains operator and retains related working interests.

Acquisition — In addition to the varying interests acquired in our Kerr-McGee exploration agreement, we also acquired two Deepwater leases in the March 2004 MMS lease sale and recently were apparent high bidder on an additional two Deepwater leases in the March 2005 MMS lease sale, which are subject to the MMS review and awarding procedures. We plan to drill our first operated Deepwater well during 2005 on a lease acquired during the 2004 lease sale.

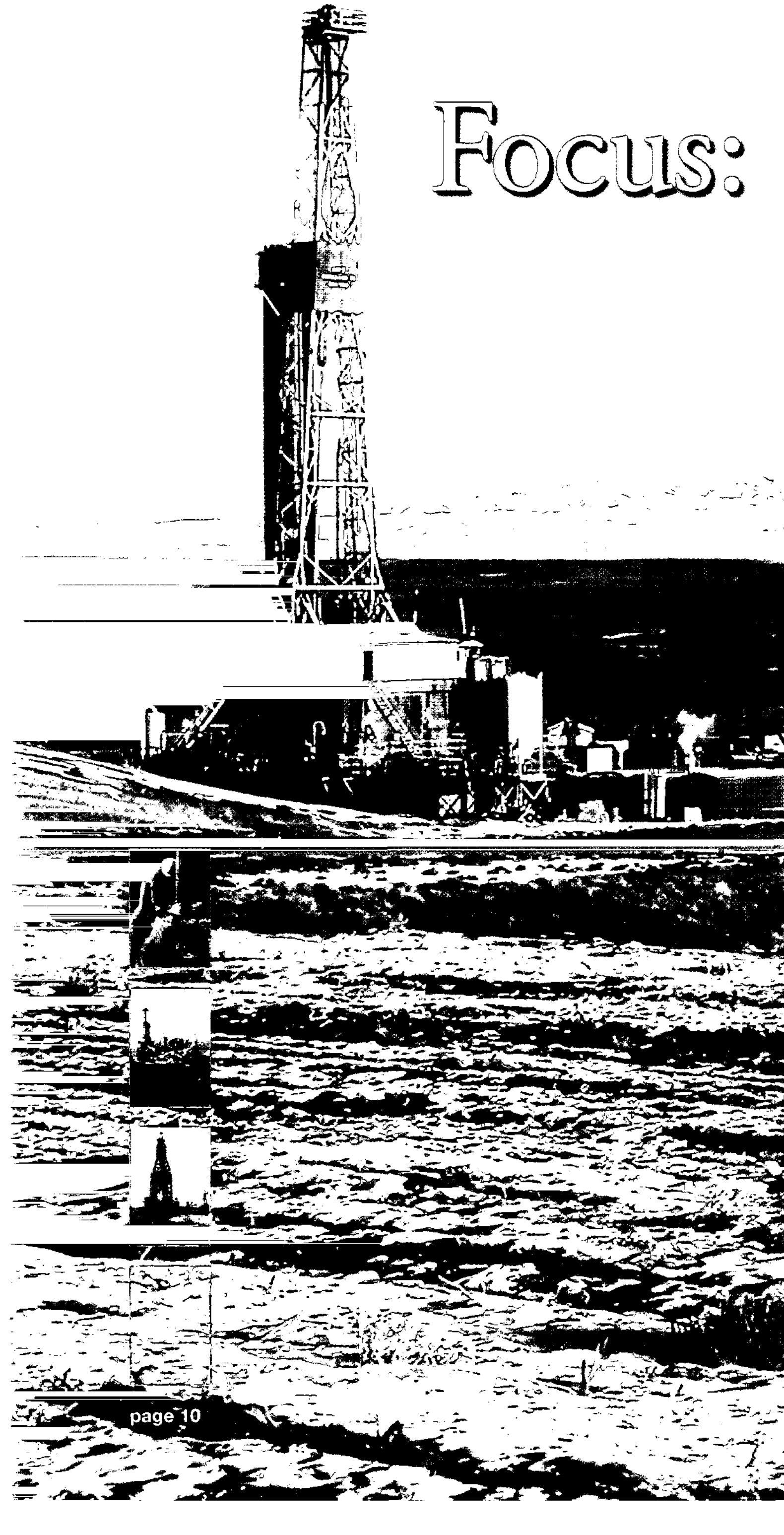
Drilling Update — Mentioned above, the well drilled to test the Essex Prospect at Mississippi Canyon Block 24 was drilled to a total measured depth of 21,887 feet and was subsequently plugged and abandoned after encountering noncommercial amounts of hydrocarbons. Our non-operating working interest was 35%. A second well, drilled to a total measured depth of 18,071 feet to test the Fawkes Prospect at Garden Banks Block 303, also encountered noncommercial amounts of hydrocarbon, although the targeted reservoir was identified by seismic amplitude. The well was then sidetracked to target the main zone updip to the original well. The main zone was "wet" so the well was permanently abandoned. Our non-operating working interest was 16.7%.

While our drilling results in the Deepwater thus far have not been satisfying, we realize that the success of just one of our Deepwater prospects will make the entire project profitable, given the significant exploration potential in each well. For 2005, we plan to spend 15% of our estimated capital budget on exploration in the Deepwater, which currently includes the drilling of six wells.

"Stone is different from other companies in the industry in that we execute a focused development, exploration and acquisition strategy. The Company is financially strong with the ability to make informed decisions quickly. Operating with an experienced technical team, coupled with new technologies, enables us to find new oil and gas reservoirs more accurately and efficiently."

Stacey Frederick,
Acquisitions Manager

Focus: Rocky Mountains



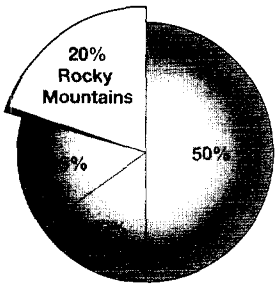
We consider our assets in the Rockies to be an important component of our diversification and continued growth. Currently, our Rocky Mountain assets represent less than 11% of our total production and reserves. For 2005, we expect to increase our investment in this region and are building a foundation for the development of this area through large acreage acquisitions.

We are currently active in the vicinity of the Howard Ranch field in the northern Wind River Basin of Wyoming. This property was acquired by acreage acquisitions in 2002 and 2004. Our 2005 drilling program for this field will be designed pending the completion of our processing and evaluation of a 70-square-mile seismic survey required for the determination of future drilling sites.

In the Greater Green River Basin of Wyoming, we continue to be successful on the Pinedale Anticline. Since our entry into this field in 2002, we have drilled 18 consecutive successes, eight of which were drilled in 2004. We continue to operate the drilling portion of this project with a 50% working interest, while our partner is operating the completion phase, consisting of multiple-stage hydraulic fracturing.

The map at right illustrates our current areas of operation in the Rocky Mountains. With the recent completions of exploratory acreage positions in Utah and in the Williston Basin of North Dakota and Montana, we hold rights to over 240,000 net acres in this region for future exploration and development opportunities.

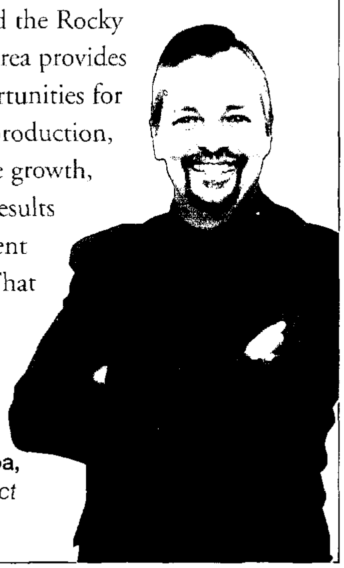
Estimated 2005 Capital Spending



Acquisitions — During 2004, we acquired the leasehold rights to approximately 27,000 net acres in Utah where we intend to test the coal bed methane potential of this acreage at depths of 2,000 to 4,000 feet with an exploratory program of three to five wells during 2005, to be followed by a development program if successful. Located approximately 40 miles southeast of our Monument Butte field, this project represents our first move into a coal bed methane play.

We have also acquired approximately 47,000 net acres of deep rights below the Monument Butte field in the Uinta Basin in Utah, an area characterized by extensive ongoing industry activity. This property is primarily held by shallow production, which provides us with a long-term investment opportunity to exploit tight gas reservoirs in Tertiary and Cretaceous age Wasatch and Mesaverde sandstones.

"Our job in Denver is to execute the vision of our management in diversifying the investment portfolio of Stone. Diversification is critical to any portfolio of assets and the Rocky Mountain area provides many opportunities for long-lived production, solid reserve growth, repeatable results and consistent cash flow. That adds value to shareholders."



Michael Cuba,
Denver District Manager

Announced at year-end 2004 and completed in March 2005, we acquired approximately 35,000 net exploratory acres in the Williston Basin of North Dakota and Montana. The Williston Basin acreage is located within the Bakken formation fairway with potential stacked oil pay sands. The acquisition cost totaled approximately $86 million. We expect to begin exploring the acreage with a multi-well, horizontal drilling program during the second quarter of 2005.

Divestments — During 2004, our management elected to sell certain tail-end properties that were considered non-core or non-essential to the future growth of our business in the Rockies. The properties that were sold represented approximately 1% of Stone's estimated year-end 2003 proved reserves. The proceeds from these divestments were redeployed toward expanding our position in the region.

Board of Directors

James H. Stone
Stone Energy Corporation
Chairman

James H. Stone retired as Chief Executive Officer of Stone Energy on December 31, 2000.

Peter K. Barker [1,3]
Goldman Sachs & Co.
Retired Partner

Peter K. Barker is an Advisory Director of Goldman Sachs & Co. Mr. Barker headed Goldman Sachs' investment banking activities on the West Coast from 1978 to 1998. He is also chairman of Stone's Audit Committee.

Robert A. Bernhard [1,3]
MB Investment Partners

Robert A. Bernhard is currently a partner of MB Investment Partners, an investment advising firm.

D. Peter Canty
Stone Energy Corporation
Former President and Chief Executive Officer

D. Peter Canty was elected Chief Executive Officer of Stone Energy on December 31, 2000, and served in that role until his retirement on April 1, 2004.

Lt. Gen. George R. Christmas (Ret.) [2,3]
Marine Corps Heritage Foundation
President

Lieutenant General George R. Christmas retired from active duty in the U.S. Marine Corps in September 1996 after an exemplary and highly decorated military career. He currently serves as President of the Marine Corps Heritage Foundation.

B.J. Duplantis [3]
Gordon, Arata, McCollam, Duplantis & Eagan
Senior Partner

B.J. Duplantis is the managing partner of the law firm Gordon, Arata, McCollam, Duplantis & Eagan. He is also chairman of Stone's Nominating and Governance Committee.

Raymond B. Gary [1,2,3]
Morgan Stanley & Company, Inc.
Advisory Director

Raymond B. Gary is an Advisory Director of Morgan Stanley Dean Witter and Company, an investment banking firm.

John P. Laborde
Tidewater Inc.
Retired Chairman Emeritus

John P. Laborde is the former Chairman, President and Chief Executive Officer of Tidewater, Inc.

Richard A. Pattarozzi [2,3]
Shell Oil Company
Former Vice President

Richard A. Pattarozzi is the former Vice President of Shell Offshore Inc. and former President and CEO of Shell Deepwater Development Inc. and Shell Deepwater Production Inc. He is also chairman of Stone's Compensation Committee.

David R. Voelker [1,2,3]
Frantzen/Voelker Investments
Owner

David Voelker is a 50% owner of Frantzen/Voelker Investments, L.L.C., which invests in emerging as well as mature companies.

David H. Welch
Stone Energy Corporation
President and Chief Executive Officer

David H. Welch was elected President, Chief Executive Officer and director of Stone Energy effective April 1, 2004. Prior to joining Stone Energy, he had served as Vice President of BP, Inc. since 1999 and, most recently, Senior Vice President of BP America, Inc. since 2003.

[1] Audit Committee Member
[2] Compensation Committee Member
[3] Nominating and Governance Committee Member

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 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

For the transition period from _______ to _______

Commission File Number: 1-12074

STONE ENERGY CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

State of Incorporation: Delaware   I.R.S. Employer Identification No. 72-1235413

625 E. Kaliste Saloom Road
Lafayette, Louisiana   70508
(Address of Principal Executive Offices)   (Zip Code)

Registrant's Telephone Number, Including Area Code: (337) 237-0410

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

Title of each class	Name of each exchange on which registered
Common Stock, Par Value $.01 Per Share	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.

[x] Yes   [ ] 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 the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).

[x] Yes   [ ] No

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $1,107,417,271 as of June 30, 2004 (based on the last reported sale price of such stock on the New York Stock Exchange Composite Tape on that day).

As of March 1, 2005, the registrant had outstanding 26,681,912 shares of Common Stock, par value $.01 per share.

Document incorporated by reference: Portions of the Definitive Proxy Statement of Stone Energy Corporation relating to the Annual Meeting of Stockholders to be held on May 18, 2005 are incorporated by reference into Part III of this Form 10-K.

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PART I

This section highlights information that is discussed in more detail in the remainder of the document. Throughout this document we make statements that are classified as "forward-looking." Please refer to the "Forward-Looking Statements" section beginning on page 8 of this document for an explanation of these types of statements. We use the terms "Stone", "Stone Energy", "company", "we", "us" and "our" to refer to Stone Energy Corporation. Certain terms relating to the oil and gas industry are defined in "Glossary of Certain Industry Terms", which begins on page G-1 of this Form 10-K.

ITEM 1. BUSINESS

The Company

Stone Energy is an independent oil and gas company engaged in the acquisition and subsequent exploration, development, operation and production of oil and gas properties located in the conventional shelf of the Gulf of Mexico (the "GOM"), the deep shelf of the GOM, the deepwater of the GOM and several basins of the Rocky Mountains. Our corporate headquarters are located at 625 E. Kaliste Saloom Road, Lafayette, Louisiana 70508.

Available Information

We make available free of charge on our Internet web site (www.stoneenergy.com) our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the Securities and Exchange Commission (the "SEC"). We also make available on our Internet web site our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation and Nominating and Governance Committee Charters, respectively, which have been approved by our board of directors. We will make immediate disclosure by a current report on Form 8-K and on our web site of any change to, or waiver from, the Code of Business Conduct and Ethics for our principal executive and senior financial officers.

Strategy and Operational Overview

Since our public offering in 1993, we have increased reserves, production and cash flow primarily through the acquisition, exploration and development of mature oil and gas properties in the Gulf Coast Basin, which includes onshore Louisiana and offshore GOM. During this period, we have grown reserves, production and cash flow from operating activities at compounded annual rates of 22%, 21% and 35%, respectively. During 2004, we broadened our conventional shelf acquisition and exploitation strategy in order to diversify, extend reserve life and take advantage of a strong oil and gas market. This broadened growth strategy includes targeting reserves and production in the deep water of the GOM and furthering our position in the Rocky Mountains to complement our existing portfolio of properties in the Gulf Coast Basin (onshore, shelf and deep shelf). Our strategy is driven by increased availability of lease blocks in the deep water of the GOM, 3D seismic technology improvements in the deep shelf of the GOM and fracturing technology improvements in the Rocky Mountains. As of March 1, 2005, our property portfolio consisted of 59 active properties and 53 primary term leases in the Gulf Coast Basin and 13 active properties in the Rocky Mountains.

As of December 31, 2004, we had estimated proved reserves of approximately 825 billion cubic feet of gas equivalent (Bcfe), 73% of which were classified as proved developed and 59% of which were natural gas. For the year ended December 31, 2004, we produced an average of 241 million cubic feet of gas equivalent (MMcfe) per day, which was curtailed due to extended production downtime associated with Hurricane Ivan. During 2004, we generated net cash flow from operating activities of $369.5 million.

Gulf of Mexico — Conventional Shelf

Our conventional shelf strategy is the same acquisition and exploitation combination that we adopted prior to our initial public offering in 1993. We apply the latest geophysical interpretation tools to identify underdeveloped properties and the latest production techniques to increase production attributable to these properties. We believe significant reserves remain to be discovered and exploited on properties that satisfy our acquisition criteria. We also believe that we are well positioned to exploit these reserves by applying our technical expertise in a thorough and consistent approach to the evaluation and acquisition of these properties.

In the Gulf of Mexico, we seek to acquire properties that have the following characteristics:

- mature properties with an established production history and infrastructure;
- multiple productive sands and reservoirs;
- low production levels at acquisition with significant identified proven and potential reserves; and
- opportunity for us to obtain a controlling interest and serve as operator.

Using our extensive production history and data accumulated on properties in the Gulf Coast Basin, our experienced technical teams construct an interpretation of the unique geology of each field to gain a better understanding of the potential location of previously untested or unexploited oil and gas accumulations. Using our interpretations, we are frequently able to combine development and exploratory targets in a single well to improve the chance of investment success. Since 1993, 75% of the wells we drilled were productive.

Prior to acquiring a property, we perform a thorough geological, geophysical and engineering analysis of the property to formulate a comprehensive development plan. We also employ our extensive technical database, which includes both 3-Dimensional and 4-Component seismic data. After we acquire a property, we seek to increase cash flow from existing reserves and establish additional proved reserves through the drilling of new wells, workovers and recompletions of existing wells and the application of other techniques designed to increase production.

Gulf of Mexico — Deep Water

We believe that the deep water of the Gulf of Mexico is a compelling exploration area and have assembled a technical team with prior geological, geophysical and engineering experience in the deep water arena to evaluate potential opportunities. During 2004, we entered into an exploration agreement with Kerr-McGee Oil and Gas Corp. covering several undeveloped leases in the GOM. Under the agreement, we acquired varying interests in these deep water and deep shelf leases and will participate in five commitment wells to be drilled by the end of 2005, two of which have been drilled. In addition, we also intend to evaluate additional drilling opportunities on the respective leases through 2006.

Gulf of Mexico — Deep Shelf

Our current property base also contains multiple deep shelf exploration opportunities in the GOM, which are defined as prospects below 15,000 feet. The deep shelf presents higher risk with high potential opportunities that have existing infrastructure, which shortens the lead time to production. The exploration agreement with Kerr-McGee, noted above, combined with our existing property base creates the opportunity for a portfolio approach to the deep shelf.

Rocky Mountains

Although currently less than 11% of our total production and reserves, we consider the assets in the Rockies to be an important component of our continued growth and expect to increase our investment in this region. We are continuing to build a foundation for this business through large acreage acquisitions.

We are currently active in the vicinity of the Howard Ranch Field in the northern Wind River Basin of Wyoming. This property was acquired by acreage acquisitions in 2002 and 2004. Processing of a 70 square mile seismic survey is currently underway that will allow for interpretation of well locations for our 2005 drilling program in this field. We have also acquired approximately 47,000 net acres of deep rights below the Monument Butte Field in the Uinta Basin of Utah. There is extensive ongoing industry activity in areas around this acreage block. We also operate in the Greater Green River Basin of Wyoming with continued success on the Pinedale Anticline.

During 2004, we acquired the leasehold rights to approximately 27,000 net acres in Utah. We intend to test the coalbed methane potential of this acreage at depths of 2,000 to 4,000 feet with a three to five well exploratory program during 2005 followed by a development program if exploration is successful. This project, which is located approximately 40 miles southeast of our Monument Butte field, represents our first move into a coalbed methane play.

On March 1, 2005, we completed the acquisition of approximately 35,000 net exploratory acres in the Williston Basin of North Dakota and Montana. The acquisition cost, net of purchase price adjustments, totaled approximately $85.7 million, of which $76.0 million was financed with borrowings under Stone's bank credit facility. Approximately 75% of the net purchase price has been allocated to unevaluated costs. We expect to begin exploring the acreage with a multi-well drilling program in 2005.

Oil and Gas Marketing

Our oil and natural gas production is sold at current market prices under short-term contracts providing for variable or market sensitive prices. BP Energy Company, Cinergy Marketing and Trading, Conoco, Inc., Equiva Trading Company and Total Gas & Power North America, Inc. each accounted for between 10%-13% of oil and natural gas revenue generated during the year ended December 31, 2004. No other purchaser accounted for 10% or more of our total oil and natural gas revenue during 2004. We believe that the loss of any of our major purchasers would not result in a material adverse effect on our ability to market future oil and gas production. From time to time, we may enter into transactions that hedge the price of oil and natural gas. See **"Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk."**

Competition and Markets

Competition in the Gulf Coast Basin and the Rocky Mountains is intense, particularly with respect to the acquisition of producing properties and undeveloped acreage. We compete with major oil and gas companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of our competitors have financial resources and exploration and development budgets that are substantially greater than ours, which may adversely affect our ability to compete. See **"Risk Factors – Competition within our industry may adversely affect our operations."**

The availability of a ready market for and the price of any hydrocarbons produced will depend on many factors beyond our control, including but not limited to the amount of domestic production and imports of foreign oil and liquefied natural gas, the marketing of competitive fuels, the proximity and capacity of natural gas pipelines, the availability of transportation and other market facilities, the demand for hydrocarbons, the effect of federal and state regulation of allowable rates of production, taxation and the conduct of drilling operations, and federal regulation of natural gas. In addition, the restructuring of the natural gas pipeline industry virtually eliminated the gas purchasing activity of traditional interstate gas transmission pipeline buyers. Producers of natural gas have therefore been required to develop new markets among gas marketing companies, end users of natural gas and local distribution companies. All of these factors, together with economic factors in the marketing arena, generally may affect the supply of and/or demand for oil and natural gas and thus the prices available for sales of oil and natural gas.

Regulation

Our oil and gas operations are subject to various U.S. federal, state and local laws and regulations.

Various aspects of our oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the Federal government for operations on Federal leases. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions requiring permits for the drilling of wells and maintaining bonding requirements in order to drill or operate wells, and provisions relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the number of wells that may be drilled in an area and the unitization or pooling of oil and natural gas properties. In this regard, some states can order the pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Certain operations that we conduct are on federal oil and gas leases, which are administered by the Bureau of Land Management (the "BLM") and the Minerals Management Service (the "MMS"). These leases contain relatively standardized terms and require compliance with detailed BLM and MMS regulations and orders pursuant to the Outer Continental Shelf Lands Act (the "OCSLA") (which are subject to change by the MMS). Many onshore leases contain stipulations limiting activities that may be conducted on the lease. Some stipulations are unique to particular geographic areas and may limit the times during which activities on the lease may be conducted, the manner in which certain activities may be conducted or, in some cases, may ban any surface activity. For offshore operations, lessees must obtain MMS approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies (such as the Environmental Protection Agency), lessees must obtain a permit from the BLM or the MMS, as applicable, prior to the commencement of drilling, and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on Outer Continental Shelf (the "OCS") of the GOM, 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, unless the MMS exempts the lessee from such obligations. The cost of such bonds or other surety can be substantial, and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. Under certain circumstances, the BLM or MMS, as applicable, may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by Congress, states, the Federal Energy Regulatory Commission (the "FERC") and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. We can give no assurance that the regulatory approach currently pursued by the FERC will continue indefinitely. We do not anticipate, however, that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect on our financial condition, results of operations or competitive position. No portion of our business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the Federal government.

Environmental Regulation

As a lessee and operator of onshore and offshore oil and gas properties in the United States, we are subject to stringent federal, state and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including wastes generated in connection with oil and gas industry operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, limit or prohibit the extent to which exploration and development may be allowed, and require proper closure of wells and restoration of properties that are being abandoned. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, imposition of remedial obligations, incurrence of capital costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production operations or the disposal of substances generated in connection with oil and gas industry operation.

We currently operate or lease, and have in the past operated or leased, a number of properties that for many years have been used for the exploration and production of oil and gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability without regard to fault or the legality of the original conduct that could require us to remove or remediate previously disposed wastes or property contamination, or to perform remedial plugging or pit closure to prevent future contamination. We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards.

We have made, and will continue to make, expenditures in efforts to comply with environmental laws and regulations. While we believe that we are in substantial compliance with applicable environmental laws and regulations in effect and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future.

We have established internal guidelines to be followed in order to comply with environmental laws and regulations in the United States. We employ a safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although we maintain pollution insurance against the costs of cleanup operations, public liability and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future. To date we believe that compliance with existing requirements of such governmental bodies has not had a material effect on our operations.

Employees

On March 1, 2005, we had 236 full time employees. We believe that our relationships with our employees are satisfactory. None of our employees are covered by a collective bargaining agreement. Under our supervision, we utilize the services of independent contractors to perform various daily operational duties for our offshore GOM properties.

Forward-Looking Statements

The information in this Form 10-K includes "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 or present facts, that address activities, events, outcomes and other matters that we plan, expect, intend, assume, believe, budget, predict, forecast, project, estimate or anticipate (and other similar expressions) will, should or may occur in the future are forward-looking statements. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10-K.

Forward-looking statements appear in a number of places and include statements with respect to, among other things:

- any expected results or benefits associated with our acquisitions;
- estimates of our future oil and natural gas production, including estimates of any increases in oil and gas production;
- planned capital expenditures and the availability of capital resources to fund capital expenditures;
- our outlook on oil and gas prices;
- estimates of our oil and gas reserves;
- any estimates of future earnings growth;
- the impact of political and regulatory developments;
- our outlook on the resolution of pending litigation;
- our future financial condition or results of operations and our future revenues and expenses; and
- our business strategy and other plans and objectives for future operations.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and marketing of oil and natural gas. These risks include, but are not limited to, commodity price volatility, third party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures and the other risks described in this Form 10-K.

Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by geological engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, these revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

Risk Factors

Our business is subject to a number of risks including, but not limited to, those described below:

Oil and gas price declines and volatility could adversely affect our revenues, cash flows and profitability.

Our revenues, profitability and future rate of growth depend substantially upon the market prices of oil and natural gas, which fluctuate widely. Factors that can cause this fluctuation include:

- relatively minor changes in the supply of and demand for oil and natural gas;
- market uncertainty;
- the level of consumer product demands;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political and economic conditions in oil producing countries, particularly those in the Middle East;
- the foreign supply of oil and natural gas;
- the price of oil and gas imports; and
- overall domestic and foreign economic conditions.

We cannot predict future oil and natural gas prices. At various times, excess domestic and imported supplies have depressed oil and gas prices. Declines in oil and natural gas prices may adversely affect our financial condition, liquidity and results of operations. Lower prices may reduce the amount of oil and natural gas that we can produce economically and may also create ceiling test write-downs of our oil and gas properties. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices, not long-term fixed price contracts.

In an attempt to reduce our price risk, we periodically enter into hedging transactions with respect to a portion of our expected future production. We cannot assure you that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. Any substantial or extended decline in the prices of or demand for oil or natural gas would have a material adverse effect on our financial condition and results of operations.

The marketability of our production depends mostly upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities.

The marketability of our production depends upon the availability, proximity, operation and capacity of gas gathering systems, pipelines and processing facilities. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal, state and local regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand could adversely affect our ability to produce and market our oil and natural gas. If market factors changed dramatically, the financial impact on us could be substantial. The availability of markets and the volatility of product prices are beyond our control and represent a significant risk.

We may not receive payment for a portion of our future production.

We may not receive payment for a portion of our future production. We have attempted to diversify our sales and obtain credit protections such as parental guarantees from certain of our purchasers. We are unable to predict, however, what impact the financial difficulties of certain purchasers may have on our future results of operations and liquidity.

Estimates of oil and gas reserves are uncertain and inherently imprecise.

This Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon 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 oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Although 100% of our estimated proved reserves as of December 31, 2004 were determined by independent reserve engineers, these estimates are inherently imprecise.

Actual future production, oil and natural 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 set forth in this document and the information incorporated by reference. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2004, approximately 27% of our estimated proved reserves were proved undeveloped and 52% were proved developed non-producing. The increase in proved developed non-producing reserves as of December 31, 2004 is primarily the result of reserves associated with producing fields that were shut-in due to damage to downstream production facilities and pipelines owned by third parties, which impacted our ability to restore production to these fields. Proved undeveloped reserves and proved developed non-producing reserves, by their nature, are less certain than proved developed producing reserves. Estimation of these non-producing categories 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. Recovery of proved developed non-producing reserves requires capital expenditures to recomplete into the zones above producing intervals and is subject to the risk of a successful recompletion. Production revenues from proved non-producing reserves will not be realized until sometime in the future, sometimes not for many years. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our oil and gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated.

You should not assume that the present value of estimated future net cash flow referred to in this Form 10-K is the current fair value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimate of proved reserve volumes and the present value of estimated future net cash flows from proved reserves is based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for Stone.

Lower oil and gas prices may cause us to record ceiling test write-downs.

We use the full cost method of accounting for our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under full cost accounting rules, the net capitalized costs of oil and gas properties (net of related deferred taxes), including estimated capitalized abandonment costs, may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10% and excluding cash flows related to estimated abandonment costs, plus the lower of cost or fair value of unproved properties. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling test write-down." This charge does not impact cash flow from operating activities, but does reduce net income. The risk that we will be required to write down the carrying value of oil and gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. We cannot assure you that we will not experience ceiling test write-downs in the future.

We may not be able to obtain adequate financing to execute our operating strategy.

We have historically addressed our short and long-term liquidity needs through the use of bank credit facilities, the issuance of debt and equity securities and the use of cash flow provided by operating activities. We continue to examine the following alternative sources of capital:

- bank borrowings or the issuance of debt securities;
- the issuance of common stock, preferred stock or other equity securities;
- joint venture financing; and
- production payments.

The availability of these sources of capital will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, oil and natural gas prices and our market value and operating performance. We may be unable to fully execute our operating strategy if we cannot obtain capital from these sources.

We may not be able to fund our planned capital expenditures.

We spend and will continue to spend a substantial amount of capital for the acquisition, exploration, exploitation, development and production of oil and gas reserves. Our capital expenditures, including acquisitions and exclusive of estimated asset retirement costs, were $501.9 million during 2004, $362.6 million during 2003 and $215.6 million during 2002. We have budgeted total capital expenditures in 2005, excluding property acquisitions and capitalized salaries, general and administrative costs and interest, to be approximately $315 million. If low oil and natural gas prices, operating difficulties or other factors, many of which are beyond our control, cause our revenues and cash flows from operating activities to decrease, we may be limited in our ability to fund the capital necessary to complete our capital expenditures program. In addition, if our borrowing base under our credit facility is re-determined to a lower amount, this could adversely affect our ability to fund our planned capital expenditures. After utilizing our available sources of financing, we may be forced to raise additional debt or equity proceeds to fund such capital expenditures. We cannot assure you that additional debt or equity financing will be available or cash flows provided by operations will be sufficient to meet these requirements.

We may not be able to replace production with new reserves.

In general, the volume of production from oil and gas properties declines as reserves are depleted. The decline rates depend on reservoir characteristics. Gulf of Mexico reservoirs tend to be recovered quickly through production with associated steep declines, while declines in other regions after initial flush production tend to be relatively low. During 2004, 91% of our production and 89% of our estimated proved reserves were derived from Gulf of Mexico reservoirs, while the remaining portions of our production and reserves were derived from the Rocky Mountain region. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration drilling activities. Our future natural gas and oil production is highly dependent upon our level of success in finding or acquiring additional reserves.

Our recent growth is due in large part to acquisitions of producing properties. The successful acquisition of producing properties requires an assessment of a number of factors, some of which are beyond our control. These factors include recoverable reserves, future oil and gas prices, operating costs, and potential environmental and other liabilities, title issues and other factors. Such assessments are inexact and their accuracy is inherently uncertain. In connection with such assessments, we perform a review of the subject properties, which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, the review will not permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We cannot assure you that we will be able to acquire properties at acceptable prices because the competition for producing oil and gas properties is intense and many of our competitors have financial and other resources that are substantially greater than those available to us.

Our strategy includes increasing our reserves, production and cash flow by the implementation of a field-wide development plan. These development plans are formulated both prior to and after the acquisition of a property. However, we cannot assure you that our future development and exploration activities on the properties we acquire will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs.

There are uncertainties in successfully integrating our acquisitions.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results.

Our operations are subject to numerous risks of oil and gas drilling and production activities.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be found. The cost of drilling and completing wells is often uncertain. 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;
- weather conditions;
- shortages in experienced labor; and
- shortages or delays in the delivery of equipment.

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

We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may be unprofitable. Drilling activities can result in dry wells and wells that are productive but do not produce sufficient net revenue after operating and other costs to recoup drilling costs.

Our industry experiences numerous operating risks.

The exploration, development and production of oil and gas properties involves a variety of operating risks including the risk of fire, explosions, blowouts, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. If any of these industry-operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Additionally, our offshore operations are subject to the additional hazards of marine operations, such as capsizing, collision and adverse weather and sea conditions. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above.

We have begun to explore for natural gas and oil in the deep waters of the Gulf of Mexico (water depths greater than 2,000 feet) where operations are more difficult than in shallower waters. Our deep water drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. The deep waters of the Gulf of Mexico often lack the physical infrastructure and availability of services present in the shallower waters. As a result, deep water operations may require a significant amount of time between a discovery and the time that we can market the oil and gas, increasing the risks involved with these operations.

We maintain insurance of various types to cover our operations, including maritime employer's liability and comprehensive general liability. Coverage amounts are provided by primary and excess umbrella liability policies with ultimate limits of $100 million. In addition, we maintain up to $100 million in operator's extra expense insurance, which provides coverage for the care, custody and control of wells drilled and/or completed plus re-drill and pollution coverage. The exact amount of coverage for each well is dependent upon its depth and location. We experienced Gulf of Mexico production interruption in 2004 from Hurricane Ivan for which we do not have any loss of production insurance.

We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. No assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse affect on our financial condition and operations.

Terrorist attacks aimed at our facilities could adversely affect our business.

The U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack at our facilities, or those of our purchasers, could have a material adverse affect on our financial condition and operations.

A majority of our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a geographic area.

Approximately 89% of our estimated proved reserves at December 31, 2004 and 91% of our production during 2004 were associated with our Gulf Coast Basin properties. Accordingly, if the level of production from these properties substantially declines, it could have a material adverse effect on our overall production level and our revenue.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations and business prospects.

As of March 1, 2005, we had \$558.0 million in outstanding indebtedness. We have a borrowing base under our bank credit facility of \$400 million with availability of an additional \$228.9 million of borrowings as of March 1, 2005.

The terms of the agreements governing our debt impose significant restrictions on our ability to take a number of actions that we may otherwise desire to take, including:

- incurring additional debt;
- paying dividends on stock, redeeming stock or redeeming subordinated debt;
- making investments;
- creating liens on our assets;
- selling assets;
- guaranteeing other indebtedness;
- entering into agreements that restrict dividends from our subsidiary to us;
- merging, consolidating or transferring all or substantially all of our assets; and
- entering into transactions with affiliates.

Our level of indebtedness, and the covenants contained in the agreements governing our debt, could have important consequences on our operations, including:

- making it more difficult for us to satisfy our obligations under the indentures or other debt and increasing the risk that we may default on our debt obligations;
- requiring us to dedicate a substantial portion of our cash flow from operating activities 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, acquisitions 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;
- detracting from our ability to successfully withstand a downturn in our business or the economy generally;
- placing us at a competitive disadvantage against other less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under our credit facility will be at variable rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Our borrowing base under the credit facility, which is re-determined periodically, is based on an amount established by the bank group after its evaluation of our proved oil and gas reserve values. Upon a re-determination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to repay a portion of our bank debt.

We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that we will be able to generate sufficient cash flow from operating activities to pay the interest on our debt or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt. The terms of our debt, including our credit facility and our indentures, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure you that any such offering, refinancing or sale of assets can be successfully completed.

Competition within our industry may adversely affect our operations.

Competition in the Gulf Coast Basin and the Rocky Mountains is intense, particularly with respect to the acquisition of producing properties and undeveloped acreage. We compete with major oil and gas companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of our competitors have financial resources and exploration and development budgets that are substantially greater than ours, which may adversely affect our ability to compete.

Our oil and gas operations are subject to various U.S. federal, state and local governmental regulations that materially affect our operations.

Our oil and gas operations are subject to various U.S. federal, state and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions. Regulated matters include: permits for exploration, development and production operations; limitations on our drilling activities in environmentally sensitive areas, such as wetlands and restrictions on the way we can release materials in the environment; bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs; reports concerning operations, the spacing of wells and unitization and pooling of properties; and taxation. Failure to comply with these laws and regulations can result in the assessment of administrative, civil, or criminal penalties, the issuance of remedial obligations, and the imposition of injunctions limiting or prohibiting certain of our operations. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies have restricted the rates of flow of oil and gas wells below actual production capacity. In addition, the OPA requires operators of offshore facilities such as us to prove that they have the financial capability to respond to costs that may be incurred in connection with potential oil spills. Under OPA and other federal and state environmental statutes like CERCLA and RCRA, owners and operators of certain defined onshore and offshore facilities are strictly liable for spills of oil and other regulated substances, subject to certain limitations. Consequently, a substantial spill from one of our facilities subject to laws such as OPA, CERCLA and RCRA could require the expenditure of additional, and potentially significant, amounts of capital, or could have a material adverse effect on our earnings, results of operations, competitive position or financial condition. Federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and gas, by-products from oil and gas and other substances, and materials produced or used in connection with oil and gas operations. We cannot predict the ultimate cost of compliance with these requirements or their impact on our earnings, operations or competitive position.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel. We cannot assure you that individuals will remain with us for the immediate or foreseeable future. We do not have employment contracts with any of these individuals. The unexpected loss of the services of one or more of these individuals could have an adverse effect on us.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our oil and natural gas, we periodically enter into oil and gas price hedging arrangements with respect to a portion of our expected production. Our hedging policy provides that, without prior approval of our board of directors, generally not more than 50% of our estimated production quantities may be hedged. These arrangements may include futures contracts on the NYMEX. While intended to reduce the effects of volatile oil and gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and 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;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices.

Ownership of working interests, net profits interests and overriding royalty interests in certain of our properties by certain of our officers and directors may create conflicts of interest.

James H. Stone, our chairman of the board of directors, owns up to 7.5% of the working interest in certain wells drilled on Section 19 on the east flank of the Weeks Island Field. This interest was acquired prior to our initial public offering in 1993. In his capacity as a working interest owner, he is required to pay a proportional share of all costs and is entitled to receive a proportional share of revenue.

D. Peter Canty, a director and our former President and Chief Executive Officer, and James H. Prince, our Executive Vice President and Chief Financial Officer, were granted net profit interests in some of Stone's oil and gas properties acquired prior to our initial public offering in 1993. In addition, Michael E. Madden, our Vice President of Exploration and Production Technology, was granted an overriding royalty interest in some of Stone's properties by an independent third party. At the time he was granted this interest, Mr. Madden was serving Stone as an independent engineering consultant. The recipients of net profits and overriding royalty interests are not required to pay capital costs incurred on the properties burdened by such interests.

As a result of these transactions, a conflict of interest may exist between us and such directors and officers with respect to the drilling of additional wells or other development operations.

We do not pay dividends.

We have never declared or paid any cash dividends on our common stock and have no intention to do so in the near future. The restrictions on our present or future ability to pay dividends are included in the provisions of the Delaware General Corporation Law and in certain restrictive provisions in the indenture executed in connection with our 8¼% senior subordinated notes due 2011 and 6¾% senior subordinated notes due 2014. In addition, we have entered into a credit facility that contains provisions that may have the effect of limiting or prohibiting the payment of dividends.

Our Certificate of Incorporation and Bylaws have provisions that discourage corporate takeovers and could prevent stockholders from realizing a premium on their investment.

Certain provisions of our Certificate of Incorporation, Bylaws and shareholders' rights plan and the provisions of the Delaware General Corporation Law may encourage persons considering unsolicited tender offers or other unilateral takeover proposals to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. Our Bylaws provide for a classified board of directors. Also, our Certificate of Incorporation authorizes our board of directors to issue preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights of those shares, as the board may determine. Additional provisions include restrictions on business combinations and the availability of authorized but unissued common stock. 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 stockholders for their common stock.

During 1998, our board of directors adopted a shareholder rights agreement, pursuant to which uncertificated stock purchase rights were distributed to our stockholders at a rate of one right for each share of common stock held of record as of October 26, 1998. The rights plan is designed to enhance the board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect stockholders against attempts to acquire us by means of unfair or abusive takeover tactics. However, the existence of the rights plan may impede a takeover not supported by our board, including a takeover that may be desired by a majority of our stockholders or involving a premium over the prevailing stock price.

ITEM 2. PROPERTIES

We have grown principally through the acquisition and subsequent development and exploitation of properties purchased from major and independent oil and gas companies. During 2004, we implemented an broadened growth strategy designed to diversify from the conventional shelf of the GOM by exploring opportunities in the deep water environment of the GOM and expanding our Rocky Mountain asset base. See **"Item 1. Business – Strategy and Operational Overview."** As of March 1, 2005, our property portfolio consisted of 59 active properties and 53 primary term leases in the Gulf Coast Basin and 13 active properties in the Rocky Mountains.

As of March 1, 2005, we served as operator on 61% of our active properties, including a 66% operating percentage on our Gulf Coast Basin properties. The properties that we operate accounted for 75% of our year-end 2004 estimated proved reserves. This high operating percentage allows us to better control the timing, selection and costs of our drilling and production activities.

Oil and Natural Gas Reserves

The information in this annual report on Form 10-K relating to Stone's estimated oil and gas reserves and the estimated future net cash flows attributable thereto is based upon the reserve reports (the "Reserve Reports") prepared as of December 31, 2004 by Atwater Consultants, Ltd., Ryder Scott Company, L.P., Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc., all independent petroleum engineers. These independent petroleum engineers determined 100% of our estimated total proved reserves as of December 31, 2004. All product pricing and cost estimates used in the Reserve Reports are in accordance with the rules and regulations of the Securities and Exchange Commission (the "SEC"). The standardized measure of discounted future net cash flows has been calculated using a discount factor of 10%.

You should not assume that the estimated future net cash flows or the present value of estimated future net cash flows, referred to in the table below, represent the fair value of our estimated oil and gas reserves. As required by the SEC, we determine estimated future net cash flows using period-end market prices for oil and gas without considering hedge contracts in place at the end of the period. Using the information contained in the Reserve Reports, the average 2004 year-end product prices for all of our properties were $41.14 per barrel of oil and $6.58 per Mcf of gas. The following table sets forth our estimated net proved oil and natural gas reserves and the present value of estimated future net cash flows related to such reserves as of December 31, 2004.

	Proved Developed	Proved Undeveloped	Total Proved	Percent Proved Developed
Oil (MBbls)	42,152	14,408	56,560	75%
Natural gas (MMcf)	352,748	132,842	485,590	73%
Total oil and natural gas (MMcfe)	605,660	219,290	824,950	73%
Estimated future net cash flows (in thousands)	$2,355,444	$545,970	$2,901,414	81%
Standardized measure of discounted future net cash flows (in thousands)	$1,609,217	$320,514	$1,929,731	83%

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth herein only represents estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment and the existence of development plans. Results of drilling, testing and production subsequent to the date of an estimate may justify a revision of such estimates. Accordingly, reserve estimates are generally different from the quantities of oil and gas that are ultimately produced. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geological success, prices, future production levels, operating costs, development costs and income taxes that may not prove to be correct. Predictions about prices and future production levels are subject to great uncertainty, and the meaningfulness of these estimates depends on the accuracy of the assumptions upon which they are based.

As an operator of domestic oil and gas properties, we have filed Department of Energy Form EIA-23, "Annual Survey of Oil and Gas Reserves," as required by Public Law 93-275. There are differences between the reserves as reported on Form EIA-23 and as reported herein. The differences are attributable to the fact that Form EIA-23 requires that an operator report the total reserves attributable to wells that it operates, without regard to percentage ownership (*i.e.*, reserves are reported on a gross operated basis, rather than on a net interest basis) or non-operated wells in which it owns an interest.

Acquisition, Production and Drilling Activity

Acquisition and Development Costs. The following table sets forth certain information regarding the costs incurred in our acquisition, development and exploratory activities during the periods indicated.

	Year Ended December 31,		
	2004	2003	2002
		(In thousands)	
Acquisition costs, net of sales of unevaluated properties	$201,550	$54,456	$14,071
Development costs	125,161	109,507	96,426
Exploratory costs	151,571	175,864	86,063
Subtotal	478,282	339,827	196,560
Capitalized salaries, general and administrative costs and interest, net of fees and reimbursements	23,656	22,755	19,039
Asset retirement costs (1)	19,951	49,728	-
Total additions to oil and gas properties	$521,889	$412,310	$215,599

(1) Recorded in connection with the application of Statement of Financial Accounting Standards No. 143.

Productive Well and Acreage Data. The following table sets forth certain statistics regarding the number of productive wells and developed and undeveloped acreage as of December 31, 2004.

	Gross	Net
Productive Wells:		
Oil (1):		
Gulf Coast Basin	195.00	105.77
Rocky Mountain Basin	108.00	86.90
	303.00	192.67
Gas (2):		
Gulf Coast Basin	182.00	119.40
Rocky Mountain Basin	48.00	20.02
	230.00	139.42
Total	533.00	332.09
Developed Acres:		
Gulf Coast Basin	158,849.53	54,465.51
Rocky Mountain Basin	17,392.85	14,248.66
Total	176,242.38	68,714.17
Undeveloped Acres (3):		
Gulf Coast Basin	614,138.85	396,335.31
Rocky Mountain Basin	301,413.64	209,908.21
Total	915,552.49	606,243.52

(1) 15 gross wells each have dual completions.
(2) 6 gross wells each have dual completions.
(3) Leases covering approximately 5% of our undeveloped gross acreage will expire in 2005, 3% in 2006, 3% in 2007, 6% in 2008, 6% in 2009, 1% in 2011 and 1% in 2013. Leases covering the remainder of our undeveloped gross acreage (75%) are held by production.

Drilling Activity. The following table sets forth our drilling activity for the periods indicated.

	Year Ended December 31,					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive	17.00	11.02	24.00	20.81	15.00	10.59
Nonproductive	11.00	7.78	7.00	4.50	7.00	5.35
Development Wells:						
Productive	20.00	9.61	20.00	13.64	22.00	10.64
Nonproductive	3.00	2.07	1.00	0.85	4.00	2.66

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we perform a title investigation that is thorough but less vigorous than that conducted prior to drilling, which is consistent with standard practice in the oil and gas industry. Before we commence drilling operations, we conduct a thorough title examination and perform curative work with respect to significant defects before proceeding with operations. We have performed a thorough title examination with respect to substantially all of our active properties.

ITEM 3. LEGAL PROCEEDINGS

We are among the defendants included in a lawsuit filed in 2004 by the State of Louisiana and the Iberia Parish School Board in Case Number 101934, Iberia Parish, Louisiana, alleging contamination and damage to portions of Section 16, Township 12 South, Range 11 East in the Bayou Pigeon Field as a result of past oil and gas exploration and production activities. The Company believes it has been named as a defendant in error and intends to vigorously defend this matter.

We are named as a defendant in certain lawsuits and are a party to certain regulatory proceedings arising in the ordinary course of business. We do not expect these matters, individually or in the aggregate, to have a material adverse effect on our financial condition.

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

No matters were submitted for a vote of our stockholders during the fourth quarter of 2004.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth information regarding the names, ages (as of March 1, 2005) and positions held by each of our executive officers, followed by biographies describing the business experience of our executive officers for at least the past five years. Our executive officers serve at the discretion of the board of directors.

Name	Age	Position
David H. Welch	56	President, Chief Executive Officer and Director
Craig L. Glassinger	56	Executive Vice President – Business Development
James H. Prince	62	Executive Vice President and Chief Financial Officer
Andrew L. Gates, III	57	Senior Vice President, General Counsel and Secretary
E. J. Louviere	56	Senior Vice President – Land
J. Kent Pierret	49	Senior Vice President, Chief Accounting Officer and Treasurer
Gerald G. Yunker	49	Senior Vice President – Exploitation
Michael E. Madden	59	Vice President – Exploration and Production Technology
Jerome F. Wenzel, Jr.	52	Vice President – Production and Drilling
Florence M. Ziegler	44	Vice President – Human Resources

David H. Welch was appointed President, Chief Executive Officer and a director of the Company effective April 1, 2004 upon the resignation of D. Peter Canty. Mr. Welch most recently served as Senior Vice President of BP America, Inc. since 2003, and Vice President of BP, Inc. since 1999.

Craig L. Glassinger was named Executive Vice President of Business Development in April 2004. Previously, Mr. Glassinger served as Senior Vice President – Planning, Acquisitions and Analysis since April 2002. From February 2001 until April 2002, he served as Vice President – Resources and from December 1995 to February 2001 he served as Vice President – Acquisitions.

James H. Prince was named Executive Vice President in April 2004. He has previously served as Chief Financial Officer since August 1999, Chief Accounting Officer and Controller from 1993 to June 1999 and Treasurer from June 1999 to February 2004. In April 2002, he became a Senior Vice President. He has been employed by Stone Energy since its inception in 1993.

Andrew L. Gates, III was named Senior Vice President, General Counsel and Secretary in April 2004. He previously served as Vice President, General Counsel and Secretary since August 1995.

E. J. Louviere was named Senior Vice President – Land in April 2004. Previously, he served as Vice President – Land since June 1995. He has been employed by Stone since its inception in 1993.

J. Kent Pierret was named Senior Vice President in April 2004. Mr. Pierret previously served as Vice President and Chief Accounting Officer since June 1999 and Treasurer since February 2004. Prior to June 1999, he was a partner in the firm of Pierret, Veazey & Co., CPAs (and its predecessors) from May 1988 to May 1999, which performed a substantial amount of our financial reporting, tax compliance and financial advisory services.

Gerald G. Yunker was named Senior Vice President – Exploitation in April 2004 after serving as Vice President – Resources since March 2002. Previously, he served Stone Energy in various capacities as a geologist, a Development Manager, and the Planning, Acquisition & Analysis Manager from October 1994 to March 2002.

Michael E. Madden was named Vice President – Exploration and Production Technology in April 2004 and Vice President – Engineering in March 2002. Previously, he served as the Lafayette District Manager from February 2001 to March 2002. He has been employed by Stone Energy since its inception in 1993 as a reservoir engineer.

Jerome F. Wenzel, Jr. joined Stone in October 2004 as Vice President – Production and Drilling. Prior to joining Stone, Mr. Wenzel held managerial and executive positions with Amoco and BP over a 29 year career. Most recently, Mr. Wenzel was Vice President and Business Unit of INTEC Engineering.

Florence M. Ziegler was named Vice President – Human Resources in April 2004. She has been employed by Stone since its inception in 1993 and has served as the Director of Human Resources since 1997.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Since July 9, 1993, our common stock has been listed on the New York Stock Exchange under the symbol "SGY." The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock.

	High	Low
2003		
First Quarter	$36.20	$30.75
Second Quarter	44.68	33.42
Third Quarter	42.08	34.40
Fourth Quarter	43.00	34.54
2004		
First Quarter	49.57	40.55
Second Quarter	51.35	43.12
Third Quarter	47.72	38.95
Fourth Quarter	48.35	39.80
2005		
First Quarter (through March 1, 2005)	52.21	41.16

On March 1, 2005, the last reported sales price on the New York Stock Exchange Composite Tape was $49.45 per share. As of that date, there were 170 holders of record of our common stock.

Dividend Restrictions

In the past, we have not paid cash dividends on our common stock, and we do not intend to pay cash dividends on our common stock in the foreseeable future. We currently intend to retain earnings, if any, for the future operation and development of our business. The restrictions on our present or future ability to pay dividends are included in the provisions of the Delaware General Corporation Law and in certain restrictive provisions in the indenture executed in connection with our 8¼% Senior Subordinated Notes due 2011 and 6¾% Senior Subordinated Notes due 2014. In addition, our bank credit facility that contains provisions that may have the effect of limiting or prohibiting the payment of dividends.

Issuer Purchases of Equity Securities

There were no purchases of Stone's common stock by us or on our behalf during the quarterly period ended December 31, 2004.

Equity Compensation Plan Information

Please refer to Item 12 of this Annual Report on Form 10-K for information concerning securities authorized under our equity compensation plan.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2004. This information is derived from our Financial Statements and the notes thereto. See **"Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations"** and **"Item 8. Financial Statements and Supplementary Data."**

	Year Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenue:					
Oil production	$214,153	$174,139	$155,913	$103,053	$118,628
Gas production	330,048	334,166	221,582	292,446	263,310
Total operating revenue	544,201	508,305	377,495	395,499	381,938
Operating expenses:					
Lease operating expenses	100,045	72,786	76,673	54,072	48,012
Production taxes	7,408	5,975	5,039	6,408	7,607
Depreciation, depletion and amortization	188,153	170,845	160,762	158,893	110,859
Accretion expense	5,852	6,292	-	-	-
Write-down of oil and gas properties	-	-	-	237,741	-
Derivative expense	4,099	8,711	15,968	2,604	-
Bad debt expense (1)	-	-	-	2,343	-
Salaries, general and administrative expenses	14,311	14,870	13,190	13,004	12,725
Incentive compensation expense	2,318	2,636	851	523	1,722
Total operating expenses	322,186	282,115	272,483	475,588	180,925
Income (loss) from operations	222,015	226,190	105,012	(80,089)	201,013
Other (income) expenses:					
Interest expense	16,104	19,132	23,111	4,895	9,395
Other expense	1,541	538	-	-	-
Early extinguishment of debt	845	4,661	-	-	-
Merger expenses	-	-	-	25,785	1,297
Other income	(4,018)	(3,133)	(3,328)	(2,997)	(4,228)
Total other expenses, net	14,472	21,198	19,783	27,683	6,464
Income (loss) before income taxes	207,543	204,992	85,229	(107,772)	194,549
Income tax provision (benefit)	72,640	71,747	29,830	(36,397)	68,092
Income (loss) before cumulative effects of accounting changes, net of tax	134,903	133,245	55,399	(71,375)	126,457
Cumulative effects of accounting changes, net of tax (2)	-	1,225	-	-	-
Net income (loss)	$134,903	$134,470	$55,399	($71,375)	$126,457
Earnings and dividends per common share:					
Income (loss) before cumulative effects of accounting changes per share	$5.07	$5.05	$2.10	($2.73)	$4.90
Earnings (loss) per common share	$5.07	$5.10	$2.10	($2.73)	$4.90
Income (loss) before cumulative effects of accounting changes per share assuming dilution	$5.01	$5.02	$2.09	($2.73)	$4.80
Earnings (loss) per common share assuming dilution	$5.01	$5.07	$2.09	($2.73)	$4.80
Cash dividends declared	-	-	-	-	-
Cash Flow Data:					
Net cash provided by operating activities	$369,499	$391,539	$222,921	$315,617	$302,082
Net cash used in investing activities	(474,990)	(341,908)	(216,600)	(656,847)	(258,637)
Net cash provided by (used in) financing activities	112,648	(60,140)	8,133	275,828	17,461
Balance Sheet Data (at end of period):					
Working capital (deficit)	($28,598)	($38,474)	($1,213)	($18,097)	$53,065
Oil and gas properties, net	1,642,539	1,317,933	1,047,936	993,906	747,574
Total assets	1,820,895	1,434,277	1,179,371	1,101,783	944,104
Long-term debt, less current portion	482,000	370,000	431,000	426,000	148,000
Stockholders' equity	854,334	710,277	577,488	530,025	587,577

(1) Relates to 100% allowance for production receivable due from Enron North America.

(2) Cumulative effects of accounting changes related to the adoption of SFAS No. 143 and change to the Units of Production method of DD&A.

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

The following discussion is intended to assist in understanding our financial position and results of operations for each of the years in the three-year period ended December 31, 2004. Our financial statements and the notes thereto, which are found elsewhere in this Form 10-K contain detailed information that should be referred to in conjunction with the following discussion. See **"Item 8. – Financial Statements and Supplementary Data."**

Executive Overview

We are an independent oil and gas company engaged in the acquisition, exploration, exploitation, development and operation of oil and gas properties located in the conventional shelf of the Gulf of Mexico (the "GOM"), deep shelf of the GOM, deep water of the GOM and several basins of the Rocky Mountains. Our business strategy, which has remained consistent since 1993, is to increase reserves, production and cash flow through the acquisition, exploitation and development of mature properties located primarily in the Gulf Coast Basin. During 2004, we implemented a broadened growth strategy designed to diversify from the conventional Gulf of Mexico Shelf by exploring opportunities in the deep water environment of the Gulf of Mexico and expanding our Rocky Mountain asset base. See **"Item 1. Business – Strategy and Operational Overview."** Our revenue, profitability and future rate of growth are dependent upon the prices of oil and natural gas. Over the last few years, the prices of oil and gas have been highly volatile. The increased volatility is attributable to a variety of factors impacting supply and demand, including weather conditions, political events and economic events we can neither control nor predict. See **"Item 1. Business – Risk Factors."**

2004 Highlights.

Our primary 2004 goals were to grow production and reserves and lower debt levels. Although our production growth was hampered by Hurricane Ivan, we did achieve other goals indicated below:

- *Deep Water Initiative* – Entered into an agreement with Kerr-McGee for exploration in the deep water and deep shelf of the Gulf of Mexico.
- *GOM Acquisition* – Completed a preferential rights acquisition of additional working interest in South Timbalier Blocks 143, 164, 165, 166 and 171.
- *Debt Offering* – Issued \$200 million of 6¾% Senior Subordinated Notes due 2014 through a private placement.
- *Rockies Acquisitions* – Completed exploration acreage acquisitions in the Williston Basin of North Dakota and Montana and potential coal-bed methane play in Utah.
- *New CEO* – The board of directors appointed David H. Welch as President, Chief Executive Officer and director of Stone effective April 1, 2004. Mr. Welch most recently served as Senior Vice President of BP America, Inc. since 2003, and Vice President of BP, Inc. since 1999. D. Peter Canty retired as President and Chief Executive Officer in April but retained his seat on the board of directors.

2005 Outlook.

Based on our outlook of commodity prices and our estimated production, we expect to finance our 2005 capital program with cash flow from operating activities. We have hedged a portion of our estimated 2005 Gulf Coast Basin oil and natural gas production with zero-premium collars. In addition, we have swap contracts for a portion of our estimated natural gas production from the Rocky Mountains. See **"Item 7A. – Quantitative and Qualitative Disclosures About Market Risk for details of hedges and our hedge strategy."**

Our 2005 capital expenditures budget is approximately \$315 million, excluding acquisitions and capitalized interest and general and administrative expenses. To the extent that our 2005 cash flow from operating activities exceeds our estimated 2005 capital expenditures, we may pay down a portion of our existing debt. If cash flow from operating activities during 2005 is not sufficient to fund estimated 2005 capital expenditures, we believe that our bank credit facility, under which we have \$228.9 million of available borrowings at March 1, 2005, will provide us with adequate liquidity.

Results of Operation

2004 Compared to 2003. The following table sets forth certain operating information with respect to our oil and gas operations and summary information with respect to our estimated proved oil and gas reserves. See **"Item 2. Properties – Oil and Gas Reserves."**

	Year Ended December 31,			
	2004	2003	Variance	% Change
Production:				
Oil (MBbls)	5,438	5,727	(289)	(5%)
Gas (MMcf)	55,544	62,536	(6,992)	(11%)
Oil and gas (MMcfe)	88,172	96,898	(8,726)	(9%)
Average prices: (1)				
Oil (per Bbl)	$39.38	$30.41	$8.97	29%
Gas (per Mcf)	5.94	5.34	0.60	11%
Oil and gas (per Mcfe)	6.17	5.25	0.92	18%
Expenses (per Mcfe):				
Lease operating expenses	$1.13	$0.75	$0.38	51%
Salaries, general and administrative expenses	0.16	0.15	0.01	7%
DD&A expense on oil and gas properties	2.10	1.73	0.37	21%
Proved Reserves at December 31:				
Oil (MBbls)	56,560	59,162	(2,602)	(4%)
Gas (MMcf)	485,590	461,323	24,267	5%
Oil and gas (MMcfe)	824,950	816,295	8,655	1%

(1) Includes the settlement of hedging contracts.

For the year 2004, we reported net income totaling $134.9 million, or $5.01 per share, compared to net income for the year ended December 31, 2003 of $134.5 million, or $5.07 per share. The variance in annual results was due to the following components:

Production. During 2004, total production volumes decreased 9% to 88.2 Bcfe compared to 96.9 Bcfe produced during 2003. Oil production during 2004 totaled approximately 5.4 million barrels compared to 2003 oil production of 5.7 million barrels, while natural gas production during 2004 totaled approximately 55.5 billion cubic feet compared to 62.5 billion cubic feet produced during 2003. The decrease in overall 2004 production, compared to 2003, was primarily the result of extended production downtime from Hurricane Ivan.

Certain fields in the Main Pass and Mississippi Canyon areas remained shut-in as of December 31, 2004 due to damage to downstream pipelines and production facilities sustained during Hurricane Ivan, which hit during the month of September. Production from certain fields previously shut-in was re-established during the first quarter of 2005 and Stone expect the remaining fields to resume production before the end of 2005.

Prices. Prices realized during 2004 averaged $39.38 per barrel of oil and $5.94 per Mcf of gas compared to 2003 average realized prices of $30.41 per barrel of oil and $5.34 per Mcf of gas. On a gas equivalent basis, average 2004 prices were 18% higher than prices realized during 2003. All unit pricing amounts include the settlement of hedging contracts.

We enter into various hedging contracts in order to reduce our exposure to the possibility of declining oil and gas prices. During 2004, hedging transactions decreased the average price we received for natural gas by $0.18 per Mcf compared to a net decrease of $0.03 per Mcf of natural gas realized during 2003. We had no hedges in place for 2003 oil production.

Oil and Gas Revenue. As a result of 18% higher realized prices on a gas equivalent basis, oil and gas revenue increased 7% to $544.2 million in 2004 from $508.3 million during 2003 despite a 9% decline in total production volumes during 2004.

Expenses. During 2004, we incurred lease operating expenses of $100.0 million, compared to $72.8 million incurred during 2003. On a unit of production basis, 2004 lease operating expenses were $1.13 per Mcfe as compared to $0.75 per Mcfe for 2003. The increase in lease operating expenses in 2004 is due to a combination of increases in overall industry service costs, additional costs associated with storm-related shut-ins and evacuations and increases in maintenance costs included in lease operating expenses during 2004. Included in lease operating expenses are maintenance costs, which represent repairs and maintenance costs that vary from year to year. Maintenance costs totaled $29.1 million in 2004 compared to $11.4 million in 2003. The increase in maintenance costs during 2004 is due primarily to $4.2 million for hurricane-related repairs in excess of estimated insurance recoveries and $6.8 million related to three replacement wells drilled during 2004.

DD&A expense on oil and gas properties for 2004 totaled $185.3 million, or $2.10 per Mcfe compared to DD&A expense of $168.0 million, or $1.73 per Mcfe in 2003. The increase in DD&A per Mcfe is attributable to the unit cost of current year reserve additions and related future development costs, exceeding the per unit amortizable base as of the beginning of the year.

During 2004 and 2003, we incurred $5.9 million and $6.3 million, respectively, of accretion expense related to the January 1, 2003 adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." Stone expects accretion expense to total approximately $7.2 million during 2005 as a result of property acquisitions and additional assets placed in service during 2004.

Derivative expenses represent primarily the cost of put contracts charged to earnings as the contracts settle during the respective periods. During 2004, we incurred derivative expenses of $4.1 million compared to $8.7 million in 2003. The decline in derivative expenses in 2004 is the result of lower costs of put contracts for 2004 hedged production volumes. For 2005, Stone currently expects no derivative expense as production hedges are with zero-premium collars and swaps.

Interest expense for 2004 totaled $16.1 million, net of $7.7 million of capitalized interest, compared to interest of $19.1 million, net of $8.6 million of capitalized interest, during 2003. The decrease in interest expense in 2004 is the result of the September 2003 redemption of our 8¾% senior subordinated notes, which lowered the average interest rate on our outstanding debt, combined with lower average borrowings outstanding during 2004.

Reserves. At December 31, 2004, our estimated proved oil and gas reserves totaled 825.0 Bcfe, compared to December 31, 2003 reserves of 816.3 Bcfe. The increase in estimated proved reserves during 2004 was the combined result of drilling results and acquisitions made during the year. Estimated proved natural gas reserves totaled 485.6 Bcf and estimated proved oil reserves totaled 56.6 MMBbls at the end of 2004. The reserve estimates were determined by independent petroleum consultants in accordance with guidelines established by the SEC.

Our standardized measure of discounted future net cash flows was $1.9 billion and $1.8 billion at December 31, 2004 and 2003, respectively. You should not assume that these estimates of future net cash flows represent the fair value of our estimated oil and natural gas reserves. As required by the SEC, we determine these estimates of future net cash flows using market prices for oil and gas on the last day of the fiscal period. The average year-end oil and gas prices on all of our properties used in determining these amounts, excluding the effects of hedges in place at year-end, were $41.14 per barrel and $6.58 per Mcf for 2004 and $31.79 per barrel and $6.30 per Mcf for 2003.

2003 Compared to 2002. The following table sets forth certain operating information with respect to our oil and gas operations and summary information with respect to our estimated proved oil and gas reserves.

	Year Ended December 31,			
	2003	**2002**	**Variance**	**% Change**
Production:				
Oil (MBbls)	5,727	6,237	(510)	(8%)
Gas (MMcf)	62,536	67,027	(4,491)	(7%)
Oil and gas (MMcfe)	96,898	104,449	(7,551)	(7%)
Average prices: (1)				
Oil (per Bbl)	$30.41	$25.00	$5.41	22%
Gas (per Mcf)	5.34	3.31	2.03	61%
Oil and gas (per Mcfe)	5.25	3.61	1.64	45%
Expenses (per Mcfe):				
Lease operating expenses	$0.75	$0.73	$0.02	3%
Salaries, general and administrative expenses	0.15	0.13	0.02	15%
DD&A expense on oil and gas properties	1.73	1.52	0.21	14%
Proved Reserves at December 31:				
Oil (MBbls)	59,162	52,019	7,143	14%
Gas (MMcf)	461,323	438,652	22,671	5%
Oil and gas (MMcfe)	816,295	750,766	65,529	9%

(1) Includes the settlement of hedging contracts.

For the year 2003, we reported net income totaling $134.5 million, or $5.07 per share, compared to net income for the year ended December 31, 2002 of $55.4 million, or $2.09 per share. The variance in annual results was due to the following components:

Production. During 2003, production volumes decreased 7% to 96.9 Bcfe compared to 104.4 Bcfe produced during 2002. Oil production during 2003 totaled approximately 5.7 million barrels compared to 2002 oil production of 6.2 million barrels, while natural gas production during 2003 totaled approximately 62.5 billion cubic feet compared to 67.0 billion cubic feet produced during 2002. The decrease in overall 2003 production, compared to 2002, was primarily the result of delays in initial production from certain discoveries made in 2003 combined with production shut-ins for weather and rig mobilization and from natural production declines.

Prices. Prices realized during 2003 averaged $30.41 per barrel of oil and $5.34 per Mcf of gas compared to 2002 average realized prices of $25.00 per barrel of oil and $3.31 per Mcf of gas. On a gas equivalent basis, average 2003 prices were 45% higher than prices realized during 2002. All unit pricing amounts include the settlement of hedging contracts.

From time to time, we enter into various hedging contracts in order to reduce our exposure to the possibility of declining oil and gas prices. During 2003, hedging transactions decreased the average price we received for natural gas by $0.03 per Mcf, compared to a net increase of $0.13 per barrel and a net increase of $0.08 per Mcf realized during 2002. We had no hedges in place for 2003 oil production.

Oil and Gas Revenue. As a result of 45% higher realized prices on a gas equivalent basis, offset in part by a 7% decline in production, oil and gas revenue increased 35% to $508.3 million in 2003 from $377.5 million during 2002.

Expenses. During 2003, we incurred lease operating expenses, including maintenance costs, of $72.8 million, compared to $76.7 million incurred during 2002. On a unit of production basis, 2003 lease operating expenses were $0.75 per Mcfe as compared to $0.73 per Mcfe for 2002. Maintenance costs, which represent repairs and maintenance costs that vary from year to year, totaled $11.4 million in 2003 compared to $15.7 million in 2002.

Effective January 1, 2003, management elected to change to the Units of Production (UOP) method of amortizing proved oil and gas property costs from the formerly used Future Gross Revenue (FGR) method. Under the UOP method, the quarterly provision for depreciation, depletion and amortization (DD&A) is computed by dividing production volumes for the period by the total proved reserves, and applying the respective rate to the net cost of proved oil and gas properties, including future development costs. Under the FGR method, the DD&A rate was calculated by dividing revenue for the period by future gross revenue. Management believes that this change in method is preferable because it removes fluctuations in DD&A expense caused by product pricing volatility within a reporting period and is a method more widely used in the oil and gas industry. The cumulative effect of the change in accounting principle of $4.0 million, net of tax, was recorded as a charge during 2003.

DD&A expense on oil and gas properties under the UOP method for 2003 totaled $168.0 million, or $1.73 per Mcfe. Under the FGR method, DD&A expense during 2002 was $158.3 million, or $1.52 per Mcfe. DD&A expense, as adjusted for the new method of accounting, would have been $166.9 million, or $1.60 per Mcfe, for 2002. The increase in DD&A per Mcfe is attributable to the unit cost of current year reserve additions, including increases in future development costs, exceeding the per unit amortizable base as of the beginning of the year. DD&A under the FGR method for the year ended December 31, 2002 was positively impacted by higher period-end oil and gas prices for 2002. See **"Accounting Matters and Critical Accounting Policies – Changes in Accounting Principles."**

During 2003, we incurred $6.3 million of accretion expense related to the January 1, 2003 adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations."

Due to our progress in reaching certain of our annual performance goals, incentive compensation expense increased to $2.6 million during 2003 compared to $0.9 million during 2002.

Derivative expenses represent primarily the cost of put contracts charged to earnings as the contracts settle during the respective periods. During 2003, we incurred derivative expenses of $8.7 million compared to $16.0 million in 2002. The decline in derivative expenses in 2003 is the result of no oil put contracts for 2003 production volumes and a lower cost of our natural gas put contracts.

Effective September 30, 2003, we redeemed our outstanding $100 million aggregate principal amount of 8¾% senior subordinated notes due 2007 with cash and borrowings available under our bank credit facility. As a result of the redemption of these Notes and repayments on the bank credit facility of $61.0 million, interest expense during 2003 was 17% lower than 2002. Interest expense for 2003 totaled $19.1 million, net of $8.6 million of capitalized interest, compared to interest of $23.1 million, net of $8.5 million of capitalized interest, during 2002.

Reserves. At December 31, 2003, our estimated proved oil and gas reserves totaled 816.3 Bcfe, compared to December 31, 2002 reserves of 750.8 Bcfe. The 9% increase in estimated proved reserves during 2003 was the combined result of drilling results and acquisitions made during the year. Estimated proved natural gas reserves totaled 461.3 Bcf and estimated proved oil reserves totaled 59.2 MMBbls at the end of 2003. The reserve estimates were prepared by independent petroleum consultants in accordance with guidelines established by the SEC.

Our standardized measure of discounted future net cash flows before income taxes was $1.8 billion and $1.4 billion at December 31, 2003 and 2002, respectively. You should not assume that these estimates of future net cash flows represent the fair value of our estimated oil and natural gas reserves. As required by the SEC, we determine these estimates of future net cash flows using market prices for oil and gas on the last day of the fiscal period. The average year-end oil and gas prices on all of our properties used in determining these amounts, excluding the effects of hedges in place at year-end, were $31.79 per barrel and $6.30 per Mcf for 2003 and $30.41 per barrel and $4.86 per Mcf for 2002.

Liquidity and Capital Resources

Cash Flow and Working Capital. Net cash flow provided by operating activities totaled $369.5 million during 2004 compared to $391.5 million and $222.9 million in 2003 and 2002, respectively. Based on our outlook of commodity prices and our estimated production, we expect to fund our 2005 capital expenditures with cash flow provided by operating activities.

Net cash flow used in investing activities totaled $475.0 million, $341.9 million and $216.6 million during 2004, 2003 and 2002, respectively, which primarily represents our investment in oil and gas properties.

Net cash flow provided by (used in) financing activities totaled $112.6 million, ($60.1) million and $8.1 million for the years ended December 31, 2004, 2003 and 2002, respectively. Net cash flow provided by financing activities generated during 2004 primarily relates to the proceeds from our 6¾% Senior Subordinated Notes offering offset in part by the use of offering proceeds to repay borrowings under our bank credit facility. Net cash flow used in financing activities during 2003 was the result of the $61.0 million of repayments under the amended credit facility. As a result of these activities, cash and cash equivalents increased from $17.1 million as of December 31, 2003 to $24.3 million as of December 31, 2004.

We had a working capital deficit at December 31, 2004 of $28.6 million. Working capital deficits are not unusual at the end of a period, and are usually the result of accounts payable related to ongoing exploration and development activity. We believe that our working capital balance should be viewed in conjunction with availability of borrowings under our bank credit facility when measuring liquidity. "Liquidity" is defined as the ability to obtain cash quickly either through the conversion of assets or incurrence of liabilities. See "***Bank Credit Facility.***"

Capital Expenditures. Capital expenditures during 2004 totaled $521.9 million and included $201.5 million of acquisitions cost, $20.0 million of asset retirement costs and adjustments associated with SFAS No. 143, $16.0 million of capitalized salaries, general and administrative costs, net of overhead reimbursements, and $7.7 million of capitalized interest. These investments were funded by cash flows provided by operating activities, borrowings under our bank credit facility and working capital.

Our 2005 capital expenditures budget, excluding acquisitions and capitalized interest and general and administrative expenses, is approximately $315 million, or 14% higher than our 2004 capital expenditures, excluding acquisitions, asset retirement costs and capitalized interest and general and administrative expenses. Based on our outlook of commodity prices and our estimated production, we expect to fund our 2005 capital program with cash flow provided by operating activities.

To the extent that 2005 cash flow from operating activities exceeds our estimated 2005 capital expenditures, we may pay down a portion of our existing debt. If cash flow from operating activities during 2005 is not sufficient to fund estimated 2005 capital expenditures, we believe that our bank credit facility will provide us with adequate liquidity.

We do not budget acquisitions; however, we are continually evaluating opportunities that fit our specific acquisition profile. See **"Item 1. Business – Strategy and Operational Overview."** Any one or a combination of certain of these possible transactions could fully utilize our existing sources of capital. Although we have no current plans to access the public markets for purposes of capital, if the opportunity arose, we would consider such funding sources to provide capital in excess of what is currently available to us.

Production Marketing Risk. We may not receive payment for a portion of our future production. We have attempted to diversify our sales and obtain credit protections such as parental guarantees from certain of our purchasers. We are unable to predict, however, what impact the financial difficulties of certain purchasers may have on our future results of operations and liquidity. See **"Item 1. Business – Risk Factors."**

Reserve Replacement Risk. In general, the volume of production from oil and gas properties declines as reserves are depleted. The decline rate depends on reservoir characteristics. Our proved reserves are primarily derived from Gulf of Mexico reservoirs. Gulf of Mexico reserves tend to be recovered quickly through production with associated steep declines, while declines in other regions after initial flush production tend to be relatively low. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration drilling activities. Our future natural gas and oil production, and corresponding revenues and cash flows, are highly dependent upon our level of success in finding or acquiring additional reserves. See **"Item 1. Business – Risk Factors."**

Bank Credit Facility. At March 1, 2005, we had $158.0 million of borrowings outstanding under our credit facility and letters of credit totaling $13.1 million had been issued pursuant to the facility. We have a borrowing base under the credit facility of $400 million, with availability of an additional $228.9 million in borrowings as of March 1, 2005. Our borrowing base under the credit facility, which is re-determined periodically, is based on an amount established by the bank group after its evaluation of our estimated proved oil and gas reserves.

Under the financial covenants of our credit facility, we must (i) maintain a ratio of consolidated debt to consolidated EBITDA, as defined in the amended credit agreement, for the preceding four quarterly periods of not greater than 3.25 to 1 and (ii) maintain a consolidated tangible net worth of at least $599 million, which is adjusted for future earnings and cash proceeds from equity offerings after December 31, 2003. In addition, the credit facility places certain customary restrictions or requirements with respect to disposition of properties, incurrence of additional debt, change of ownership and reporting responsibilities. These covenants may limit or prohibit us from paying cash dividends.

Hedging. See **"Item 7A. Quantitative and Qualitative Disclosure About Market Risk – Commodity Price Risk."**

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Contractual Obligations and Other Commitments

The following table summarizes our significant contractual obligations and commitments, other than hedging contracts, by maturity as of December 31, 2004.

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In thousands)		
Contractual Obligations and Commitments:					
8¼% senior subordinated notes due 2011	$200,000	$ -	$ -	$ -	$200,000
6¾% senior subordinated notes due 2014	200,000	-	-	-	200,000
Bank credit facility (1)	82,000	-	-	82,000	-
Asset retirement obligations	293,547	228	5,951	19,606	267,762
Exploration commitment (2)	42,187	42,187	-	-	-
Seismic data commitments (3)	41,646	19,027	22,619	-	-
Operating lease obligations	760	619	141	-	-
Total Contractual Obligations and Commitments	$860,140	$62,061	$28,711	$101,606	$667,762

(1) The bank credit facility matures on April 30, 2008. See **"Bank Credit Facility"** above.

(2) Exploration commitment relates to the joint venture agreement with Kerr-McGee for deep water and deep shelf exploration. See **"Item 1. Business – Strategy and Operational Overview."**

(3) Represents pre-commitments for seismic data purchases in the Gulf of Mexico through 2007.

Forward-Looking Statements

Certain of the statements set forth under this item and elsewhere in this Form 10-K are forward-looking and are based upon assumptions and anticipated results that are subject to numerous risks and uncertainties. See **"Item 1. Business — Forward-Looking Statements"** and **"— Risk Factors."**

Accounting Matters and Critical Accounting Policies

Changes in Accounting Principles. Effective January 1, 2003, management elected to change to the units of production ("UOP") method of amortizing proved oil and gas property costs from the previously used future gross revenue method. Under the UOP method, the quarterly provision for DD&A is computed by dividing production volumes, instead of revenue, for the period by the total proved reserves, instead of future gross revenue, as of the beginning of the period, and similarly applying the respective rate to the net cost of proved oil and gas properties, including future development costs. Management believes that this change in method is preferable because it removes fluctuations in DD&A expense caused by product pricing volatility within a reporting period and is a method more widely used in the oil and gas industry. As a result of the change in accounting principle, we recognized a charge against our 2003 net income for the cumulative transition adjustment of $4.0 million, net of tax.

In addition, management elected to begin recognizing production revenue under the Entitlement method of accounting effective January 1, 2003. Under this method, revenue is deferred for deliveries in excess of our net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. The cumulative effect of adoption of the Entitlement method was immaterial.

Asset Retirement Obligations. In July 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, "Accounting for Asset Retirement Obligations," effective for fiscal years beginning after June 15, 2002. This statement requires us to record our estimate of the fair value of liabilities related to future asset retirement obligations in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of an oil and gas property's useful life. The adoption of SFAS No. 143 requires the use of management's estimates with respect to future abandonment costs, inflation, market risk premiums, useful life and cost of capital. We adopted SFAS No. 143 on January 1, 2003. Upon adoption, we recognized a gain for a cumulative transition adjustment of $5.3 million, net of tax, for existing asset retirement obligation liabilities, asset retirement costs and accumulated depreciation. In addition, we recorded a $32.1 million increase in the capitalized costs of our oil and gas properties, net of accumulated depreciation, and recognized $76.3 million in additional liabilities related to asset retirement obligations. As required by SFAS No. 143, our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

Full Cost Method. We use the full cost method of accounting for our oil and gas properties. Under this method, all acquisition, exploration, development and estimated abandonment costs, including certain related employee costs and general and administrative costs (less any reimbursements for such costs), incurred for the purpose of acquiring and finding oil and gas are capitalized. Unevaluated property costs are excluded from the amortization base until we have made a determination as to the existence of proved reserves on the respective property or impairment. We review our unevaluated properties at the end of each quarter to determine whether the costs should be reclassified to the full cost pool and thereby subject to amortization. Sales of oil and gas properties are accounted for as adjustments to the net full cost pool with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

We amortize our investment in oil and gas properties through DD&A using the UOP method. See **"Changes in Accounting Principles"** above.

We capitalize a portion of the interest costs incurred on our debt that is calculated based upon the balance of our unevaluated property costs and our weighted-average borrowing rate. During 2004, 2003 and 2002, we capitalized interest costs of $7.7 million, $8.6 million, and $8.5 million, respectively. We also capitalize the portion of salaries, general and administrative expenses that are attributable to our acquisition, exploration and development activities. During 2004, 2003 and 2002, we capitalized salaries, general and administrative costs, net of overhead reimbursements, of $16.0 million, $14.2 million, and $10.5 million, respectively.

Generally accepted accounting principles allow the option of two acceptable methods for accounting for oil and gas properties. The successful efforts method is the allowable alternative to the full cost method. The primary differences between the two methods are in the treatment of exploration costs and in the computation of DD&A. Under the full cost method, all exploratory costs are capitalized while under the successful efforts method exploratory costs associated with unsuccessful exploratory wells and all geological and geophysical costs are expensed. Under full cost accounting, DD&A is computed on cost centers represented by entire countries while under successful efforts cost centers are represented by properties, or some reasonable aggregation of properties with common geological structural features or stratigraphic condition, such as fields or reservoirs.

Under the full cost method of accounting, we are required to compare, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (based on period-end commodity prices and excluding cash flows related to estimated abandonment costs), net of related tax effect, to the net capitalized costs of proved oil and gas properties, including estimated capitalized abandonment costs, net of related deferred taxes. We refer to this comparison as a "ceiling test." If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows.

Stock-Based Compensation. On December 16, 2004, the FASB issued SFAS No. 123 (revised 2004), *Share-Based Payment*, which is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*. SFAS No. 123(R) supersedes Accounting Pronouncement Bulletin (APB) No. 25, *Accounting for Stock Issued to Employees*, and amends FASB No. 95, *Statement of Cash Flows*. Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123; however, SFAS No. 123(R) *requires* all share-based payments to employees, including grants of employee stock options, be recognized in the income statement based on their fair values. Pro forma disclosure will no longer be an alternative.

SFAS No. 123(R) permits public companies to adopt its requirements using one of two methods:

1. A "modified prospective" method in which compensation cost is recognized beginning with the effective date (a) based on the requirements of Statement 123(R) for all share-based payments granted after the effective date and (b) based on the requirements of Statement 123 for all awards granted to employees prior to the effective date of Statement 123(R) that remain unvested on the effective date.

2. A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate based on the amounts previously recognized under Statement 123 for purposes of pro forma disclosures either (a) all prior periods presented or (b) prior interim periods of the year of adoption.

SFAS No. 123(R) must be adopted no later than July 1, 2005. We expect to adopt SFAS No. 123(R) on July 1, 2005 using the modified prospective method. The Notes to Consolidated Financial Statement provide pro forma information assuming compensation expense for stock-based compensation plans had been determined consistent with the expense recognition provisions under SFAS No. 123. It is currently not known whether the implementation of this proposed Standard would result in financial results materially different from those presented.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates. Estimates are used primarily when accounting for DD&A, unevaluated property costs, estimated future net cash flow from proved reserves, taxes, costs to abandon oil and gas properties, reserves of accounts receivable, capitalized employee, general and administrative costs, fair value of financial instruments, the purchase price allocation on properties acquired and contingencies.

Derivative Instruments and Hedging Activities. Under SFAS No. 133, as amended, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. We do not use derivative instruments for trading purposes. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in equity through other comprehensive income, net of related taxes, to the extent the hedge is effective. Instruments not qualifying for hedge accounting treatment are recorded in the balance sheet and changes in fair value are recognized in earnings.

Deferred Income Taxes. Deferred income taxes have been determined in accordance with SFAS No. 109, "Accounting for Income Taxes." As of December 31, 2004, we had a net deferred tax liability of $198.1 million, which was calculated based on our assumption that it is more likely than not that we will have sufficient taxable income in future years to utilize certain tax attribute carryforwards.

For a more complete discussion of our accounting policies and procedures see our **Notes to Consolidated Financial Statements** beginning on page F-8.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including adverse changes in commodity prices and operating costs. Assuming a 10% decline in realized oil and natural gas prices, including the effects of hedging contracts, we estimate our diluted net income per share would have declined approximately 26%. Assuming the costs to operate our properties, including lease operating expenses, including maintenance cost, increased 10%, we estimate our diluted earnings per share would have declined approximately 5%. These results indicate our sensitivity to changes in market conditions as it relates to commodity prices and operating costs.

Commodity Price Risk

Our revenues, profitability and future rate of growth depend substantially upon the market prices of oil and natural gas, which fluctuate widely. Oil and gas price declines and volatility could adversely affect our revenues, cash flow provided by operating activities and profitability. In order to manage our exposure to oil and gas price declines, we occasionally enter into oil and gas price hedging arrangements to secure a price for a portion of our expected future production. We do not enter into hedging transactions for trading purposes. While intended to reduce the effects of volatile oil and gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and 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;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our hedging contracts fail to perform the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices.

Our hedging policy provides that not more than 50% of our estimated production quantities can be hedged without the consent of the board of directors.

Hedging. During 2004, we realized a net decrease in revenue from our hedging transactions of $10.1 million. Our contracts totaled 2,513 MBbls of oil and 38,430 BBtus of natural gas, which represented approximately 46% and 73%, respectively, of our total oil and gas production during 2004. We realized a net decrease in revenue during 2003 from our hedging contracts of $1.6 million. During 2003, we hedged 37,775 BBtus of natural gas, which represented approximately 60% of our natural gas production. There were no oil hedges during 2003. During 2002, we realized a net increase in revenue from our hedging transactions of $6.0 million. Our contracts totaled 4,218 MBbls of oil and 24,940 BBtus of natural gas, which represented approximately 68% and 37%, respectively, of our oil and gas production for the year.

In October 2002, we reached an agreement with Enron North America Corp. to purchase the natural gas swap contract settling subsequent to October 2002 for $5.9 million. We amortized $3.6 million of derivative expenses during 2003 related to previously recorded other comprehensive loss from the swap contract.

Derivative expenses incurred during 2004 totaled $4.1 million, which relates to the amortization of the historical cost associated with put contracts that settled during the year. During 2003, we recognized $8.7 million of derivative expenses, of which $5.1 million was associated with the costs of put contracts that settled during the year. The remaining $3.6 million of derivative expense for 2003 related to amortization of other comprehensive loss from the Enron swap.

Because over 90% of our production has historically been derived from the Gulf Coast Basin, we believe that fluctuations in prices will closely match changes in the market prices we receive for our production. Oil contracts typically settle using the average of the daily closing prices for a calendar month. Natural gas contracts typically settle using the average closing prices for near month New York Mercantile Exchange ("NYMEX") futures contracts for the three days prior to the settlement date.

Stone has entered into zero-premium collars with various counterparties for a portion of our expected 2005 oil and natural gas production from the Gulf Coast Basin. The natural gas collar settlements are based on an average of NYMEX prices for the last three days of a respective month. The oil collar settlements are based upon an average of the NYMEX closing price for West Texas Intermediate ("WTI") during the entire calendar month. The contracts require payments to the counterparties if the average price is above the ceiling price or payment from the counterparties if the average price is below the floor price. We utilized fixed-price swaps to hedge a portion of our future gas production from the Rocky Mountains. Swaps typically provide for monthly payments by us if prices rise above the swap price or to us if prices fall below the swap price. Settlements under the collar contracts are realized in oil and gas revenue.

The following tables show our hedging positions as of March 3, 2005:

	Zero-Premium Collars					
	Natural Gas			Oil		
	Daily Volume (MMBtus/d)	Floor Price	Ceiling Price	Daily Volume (Bbls/d)	Floor Price	Ceiling Price
2005	20,000	$4.50	$10.25	4,000	$28.00	$52.90
2005	20,000	4.00	13.50	4,000	28.00	52.75
2005	10,000	5.00	10.00	-	-	-
2005	10,000 (1)	5.00	10.85	-	-	-
2005	10,000 (1)	5.50	10.80	-	-	-

	Fixed Price Gas Swaps	
	Daily Volume (MMBtus/d)	Price(2)
2005	15,000	$3.42

(1) Contract hedges production from April to December 2005.
(2) Based upon Inside FERC published prices for natural gas deliveries at Kern River.

Interest Rate Risk

Stone had long-term debt outstanding of $482.0 million at December 31, 2004, of which $400.0 million, or approximately 83%, bears interest at fixed rates. The $400.0 million of fixed-rate debt is comprised of $200.0 million of 8¼% senior subordinated notes due 2011 and $200.0 million of 6¾% senior subordinated notes due 2014. The remaining $82.0 million of debt outstanding at December 31, 2004 bears interest at a floating rate under our bank credit facility. At December 31, 2004, the weighted average interest rate under our floating-rate debt was approximately 3.8%. At December 31, 2004, we had no interest rate hedge positions in place to reduce our exposure to changes in interest rates. Assuming a 200 basis point increase in market interest rates during 2004, our interest expense, net of capitalization, would have increased approximately $1.9 million, net of taxes, resulting in a $0.02 per diluted share reduction in earnings.

Fair Value of Financial Instruments

The fair value of cash and cash equivalents, net accounts receivable, accounts payable and bank debt approximated book value at December 31, 2004. At December 31, 2004, the fair value of the 8¼% senior subordinated notes due 2011 and 6¾% senior subordinated notes due 2014 totaled $216.5 million and $198.5 million, respectively. The fair value of the Notes has been estimated based on quotes from brokers. Our zero-premium collar and swap contracts are recorded on the balance sheet at fair value, which is obtained from counter-parties to the contracts.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information concerning this Item begins on Page F-1.

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

There have been no disagreements with our independent registered public accounting firm on our accounting or financial reporting that would require our independent registered public accounting firm to qualify or disclaim their report on our financial statements, or otherwise require disclosure in this annual report on Form 10-K.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and our Chief Financial Officer, with the participation of other members of our senior management, reviewed and evaluated the effectiveness of Stone's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, our chief executive officer and chief financial officer believe:

- Stone's disclosure controls and procedures were effective to ensure that information required to be disclosed by Stone in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and

- Stone's disclosure controls and procedures were effective to ensure that information required to be disclosed by Stone in the reports that it files or submits under the Securities Exchange Act of 1934 was accumulated and communicated to Stone's management, including Stone's chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control – Integrated Framework,* our management concluded that our internal control over financial reporting was effective as of December 31, 2004. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders of
Stone Energy Corporation:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Stone Energy Corporation 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 COSO criteria). Stone Energy Corporation'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 opinion.

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

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

In our opinion, management's assessment that Stone Energy Corporation maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Stone Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Stone Energy Corporation as of December 31, 2004 and 2003, and the related consolidated statement of income, cash flows, changes in stockholders' equity and comprehensive income for each of the three years in the period ended December 31, 2004 of Stone Energy Corporation and our report dated March 4, 2005, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 4, 2005

Internal Controls Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during our year ended December 31, 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

There was no information required to be reported on a current report on Form 8-K during the quarterly period ended December 31, 2004 that was not reported on a Form 8-K and otherwise required by this annual report on Form 10-K.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

See **Item 4A – Executive Officers of the Registrant** for information regarding our executive officers.

Additional information required by Item 10, including information regarding our audit committee financial experts, is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders to be held on May 18, 2005. The Company has made available free of charge on its Internet Web Site (www.StoneEnergy.com) the Code of Business Conduct and Ethics applicable to all employees of the Company including the chief executive officer, chief financial officer and principal accounting officer.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders to be held on May 18, 2005.

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

The information required by Item 12 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders to be held on May 18, 2005.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by Item 13 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders to be held on May 18, 2005.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders to be held on May 18, 2005.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) **1. Financial Statements:**

The following consolidated financial statements, notes to the consolidated financial statements and the Report of Independent Registered Public Accounting Firm thereon are included beginning on pages F-1 of this Form 10-K:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheet as of December 31, 2004 and 2003

Consolidated Statement of Income for the three years in the period ended December 31, 2004

Consolidated Statement of Cash Flows for the three years in the period ended December 31, 2004

Consolidated Statement of Changes in Stockholders' Equity for the three years in the period ended December 31, 2004

Consolidated Statement of Comprehensive Income for the three years in the period ended December 31, 2004

Notes to the Consolidated Financial Statements

2. Financial Statement Schedules:

All schedules are omitted because the required information is inapplicable or the information is presented in the Financial Statements or the notes thereto.

3. Exhibits:

3.1 -- Certificate of Incorporation of the Registrant, as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).

3.2 -- Restated Bylaws of the Registrant (incorporated by reference to Exhibit 3.2 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).

3.3 -- Certificate of Amendment of the Certificate of Incorporation of Stone Energy Corporation, dated February 1, 2001 (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K, filed February 7, 2001).

3.4 -- Amendment to restated Bylaws of the Registrant (incorporated by reference to Exhibit 3.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 001-12074)).

4.1 -- Rights Agreement, with exhibits A, B and C thereto, dated as of October 15, 1998, between Stone Energy Corporation and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A (File No. 001-12074)).

4.2 -- Amendment No. 1, dated as of October 28, 2000, to Rights Agreement dated as of October 15, 1998, between Stone Energy Corporation and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-4 (Registration No. 333-51968)).

4.3 -- Indenture between Stone Energy Corporation and JPMorgan Chase Bank dated December 10, 2001 (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-4 (Registration No. 333-81380)).

4.4 -- Indenture between Stone Energy Corporation and JPMorgan Chase Bank, National Association, as trustee, dated December 15, 2004 (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on December 15, 2004.)

†*4.5 -- Stone Energy Corporation Deferred Compensation Plan

†*4.6 -- Adoption Agreement between Fidelity Management Trust Company and Stone Energy Corporation for the Stone Energy Corporation Deferred Compensation Plan dated December 1, 2004.

†10.1 -- Deferred Compensation and Disability Agreements between TSPC and D. Peter Canty dated July 16, 1981, and between TSPC and James H. Prince dated August 23, 1981 and September 20, 1981, respectively (incorporated by reference to Exhibit 10.8 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).

†10.2 -- Conveyances of Net Profits Interests in certain properties to D. Peter Canty and James H. Prince (incorporated by reference to Exhibit 10.9 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).

†10.3 -- Deferred Compensation and Disability Agreement between TSPC and E. J. Louviere dated July 16, 1981 (incorporated by reference to Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1995 (File No. 001-12074)).

†10.4 -- Stone Energy Corporation Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.14 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1993 (File No. 001-12074)).

†10.5 -- Stone Energy Corporation Amendment to the Annual Incentive Compensation Plan dated January 15, 1997 (incorporated by reference to Exhibit 10.9 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 001-12074)).

†10.6 -- Stone Energy Corporation Revised Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 001-12074)).

†10.7 -- Stone Energy Corporation 2001 Amended and Restated Stock Option Plan (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-8 (Registration No. 333-107440)).

10.8 -- Credit Agreement between the Registrant, the financial institutions named therein and Bank of America, N.A., as administrative agent, dated April 30, 2004. (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q, filed August 9, 2004 (File No. 001-12074)).

*10.9 -- Amendment No. 1 to the Credit Agreement between the Registrant, the financial institutions named therein and Bank of America, N.A., as administrative agent, dated December 14, 2004.

†10.10 -- Stone Energy Corporation 2004 Amended and Restated Stock Incentive Plan (incorporated by reference to the Registrant's Registration Statement on Form S-8 (Registration No. 333-107440)).

†*10.11 -- Stone Energy Corporation Revised (2005) Annual Incentive Compensation Plan.

16.1 -- Letter of Arthur Andersen LLP, dated June 26, 2002, regarding change in certifying accountant (incorporated by reference to Exhibit 16.1 to the Registrant's Form 8-K, filed June 27, 2002 (File No. 001-12074)).

18.1 -- Letter of Ernst & Young LLP, dated May 13, 2003, regarding change in accounting principles (incorporated by reference to Exhibit 18.1 to the Registrant's Quarterly Report on Form 10-Q, for the period ended March 31, 2003 (File No. 001-12074)).

*21.1 -- Subsidiaries of the Registrant.

*23.1 -- Consent of Independent Registered Public Accounting Firm.

*23.2 -- Consent of Atwater Consultants, Ltd.

*23.3 -- Consent of Cawley, Gillespie & Associates, Inc.

*23.4 -- Consent of Netherland, Sewell & Associates, Inc.

*23.5 -- Consent of Ryder Scott Company, L.P.

*31.1 -- Certification of Principal Executive Officer of Stone Energy Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.

*31.2 -- Certification of Principal Financial Officer of Stone Energy Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.

*#32.1 -- Certification of Chief Executive Officer and Chief Financial Officer of Stone Energy Corporation pursuant to 18 U.S.C. § 1350.

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* Filed herewith.

† Identifies management contracts and compensatory plans or arrangements.

\# Not considered to be "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

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.

STONE ENERGY CORPORATION

Date: March 9, 2005

By: /s/ David H. Welch
David H. Welch
President and
Chief Executive Officer

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

Signature	Title	Date
/s/ James H. Stone James H. Stone	Chairman of the Board	March 9, 2005
/s/ David H. Welch David H. Welch	President, Chief Executive Officer and Director (principal executive officer)	March 9, 2005
/s/ James H. Prince James H. Prince	Executive Vice President and Chief Financial Officer (principal financial officer)	March 9, 2005
/s/ J. Kent Pierret J. Kent Pierret	Senior Vice President, Chief Accounting Officer and Treasurer (principal accounting officer)	March 9, 2005
/s/ Peter K. Barker Peter K. Barker	Director	March 9, 2005
/s/ Robert A. Bernhard Robert A. Bernhard	Director	March 9, 2005
/s/ D. Peter Canty D. Peter Canty	Director	March 9, 2005
/s/ George R. Christmas George R. Christmas	Director	March 9, 2005
/s/ B.J. Duplantis B.J. Duplantis	Director	March 9, 2005
/s/ Raymond B. Gary Raymond B. Gary	Director	March 9, 2005
/s/ John P. Laborde John P. Laborde	Director	March 9, 2005
/s/ Richard A. Pattarozzi Richard A. Pattarozzi	Director	March 9, 2005
/s/ David R. Voelker David R. Voelker	Director	March 9, 2005

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders of
Stone Energy Corporation:

We have audited the accompanying consolidated balance sheet of Stone Energy Corporation (a Delaware corporation) as of December 31, 2004 and 2003, and the related consolidated statement of income, cash flows, changes in stockholders' equity and comprehensive income 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, the financial statements referred to above present fairly, in all material respects, the financial position of Stone Energy Corporation as of December 31, 2004 and 2003, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." As also discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company elected to change to the units of production method of amortizing proved oil and gas property costs and elected to begin recognizing production revenue under the entitlement method.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Stone Energy Corporation's 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 and our report dated March 4, 2005, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 4, 2005

STONE ENERGY CORPORATION
CONSOLIDATED BALANCE SHEET
(Amounts in thousands of dollars, except per share amounts)

	December 31,	
ASSETS	**2004**	**2003**
Current assets:		
Cash and cash equivalents	$24,257	$17,100
Accounts receivable	111,398	75,066
Other current assets	9,368	5,914
Total current assets	145,023	98,080
Oil and gas properties—full cost method of accounting:		
Proved, net of accumulated depreciation, depletion and amortization of $1,516,620 and $1,319,337, respectively	1,489,498	1,210,333
Unevaluated	153,041	107,600
Building and land, net of accumulated depreciation of $1,016 and $874, respectively	5,416	5,202
Fixed assets, net of accumulated depreciation of $14,567 and $13,029, respectively	4,761	5,269
Other assets, net of accumulated depreciation and amortization of $1,539 and $2,806, respectively	23,156	7,793
Total assets	$1,820,895	$1,434,277
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$110,845	$87,646
Undistributed oil and gas proceeds	36,457	30,793
Fair value of hedging contracts	14,346	7,336
Other accrued liabilities	11,973	10,779
Total current liabilities	173,621	136,554
Long-term debt	482,000	370,000
Deferred taxes	205,331	130,935
Asset retirement obligations	103,179	78,877
Fair value of hedging contracts	-	4,770
Other long-term liabilities	2,430	2,864
Total liabilities	966,561	724,000
Commitments and contingencies		
Common stock, $.01 par value; authorized 100,000,000 shares; issued 26,709,094 and 26,432,422 shares, respectively	267	264
Treasury stock (28,182 and 29,882 shares, respectively, at cost)	(1,462)	(1,550)
Additional paid-in capital	466,478	455,391
Unearned compensation	(1,486)	-
Retained earnings	399,825	264,935
Accumulated other comprehensive loss	(9,288)	(8,763)
Total stockholders' equity	854,334	710,277
Total liabilities and stockholders' equity	$1,820,895	$1,434,277

The accompanying notes are an integral part of this balance sheet.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF INCOME
(Amounts in thousands of dollars, except per share amounts)

	Year Ended December 31,		
	2004	**2003**	**2002**
Operating revenue:			
Oil production	$214,153	$174,139	$155,913
Gas production	330,048	334,166	221,582
Total operating revenue	544,201	508,305	377,495
Operating expenses:			
Lease operating expenses	100,045	72,786	76,673
Production taxes	7,408	5,975	5,039
Depreciation, depletion and amortization	188,153	170,845	160,762
Accretion expense	5,852	6,292	-
Salaries, general and administrative expenses	14,311	14,870	13,190
Incentive compensation expense	2,318	2,636	851
Derivative expense	4,099	8,711	15,968
Total operating expenses	322,186	282,115	272,483
Income from operations	222,015	226,190	105,012
Other (income) expenses:			
Interest	16,104	19,132	23,111
Other income	(4,018)	(3,133)	(3,328)
Other expense	1,541	538	-
Early extinguishment of debt	845	4,661	-
Total other expenses, net	14,472	21,198	19,783
Net income before income taxes	207,543	204,992	85,229
Income tax provision:			
Current	-	-	-
Deferred	72,640	71,747	29,830
Total income taxes	72,640	71,747	29,830
Income before cumulative effects of accounting changes, net of tax	134,903	133,245	55,399
Cumulative effect of accounting changes, net of tax of $659	-	1,225	-
Net income	$134,903	$134,470	$55,399
Earnings per common share:			
Income before cumulative effects of accounting changes	$5.07	$5.05	$2.10
Cumulative effects of accounting changes	-	0.05	-
Earnings per common share	$5.07	$5.10	$2.10
Earnings per common share assuming dilution:			
Income before cumulative effects of accounting changes	$5.01	$5.02	$2.09
Cumulative effects of accounting changes	-	0.05	-
Earnings per common share assuming dilution	$5.01	$5.07	$2.09
Average shares outstanding	26,586	26,353	26,326
Average shares outstanding assuming dilution	26,901	26,546	26,494

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS
(Amounts in thousands of dollars)

	Year Ended December 31,		
	2004	**2003**	**2002**
Cash flows from operating activities:			
Net income	$134,903	$134,470	$55,399
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	188,153	170,845	160,762
Accretion expense	5,852	6,292	-
Deferred income tax provision	72,640	71,747	29,830
Cumulative effect of accounting changes	-	(1,225)	-
Early extinguishment of debt	845	1,744	-
Derivative expenses	4,099	8,711	15,968
Other non-cash expenses	489	522	(2,282)
Increase in accounts receivable	(36,333)	(266)	(27,813)
(Increase) decrease in other current assets	(600)	538	(253)
Increase in other accrued liabilities	5,404	4,091	6,495
Investment in derivative contracts	(1,683)	(2,932)	(15,301)
Payments on asset retirement obligations	(4,159)	(2,965)	-
Other	(111)	(33)	116
Net cash provided by operating activities	369,499	391,539	222,921
Cash flows from investing activities:			
Investment in oil and gas properties	(484,767)	(340,516)	(213,566)
Sale of proved properties	11,948	475	3,304
Sale of unevaluated properties	-	-	600
Increase in other assets	(2,171)	(1,867)	(6,938)
Net cash used in investing activities	(474,990)	(341,908)	(216,600)
Cash flows from financing activities:			
Proceeds from bank borrowings	128,000	100,000	22,000
Repayment of bank borrowings	(216,000)	(61,000)	(17,000)
Issuance of 6¾% senior subordinated notes	200,000	-	-
Redemption of 8¾% senior subordinated notes	-	(100,000)	-
Deferred financing costs	(7,107)	(582)	(287)
Proceeds from exercise of stock options	7,755	1,442	3,420
Net cash provided by (used in) financing activities	112,648	(60,140)	8,133
Net increase (decrease) in cash and cash equivalents	7,157	(10,509)	14,454
Cash and cash equivalents, beginning of year	17,100	27,609	13,155
Cash and cash equivalents, end of year	$24,257	$17,100	$27,609
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$15,214	$22,898	$22,495
Income taxes	-	-	-

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(Amounts in thousands of dollars)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholde[rs'] Equity
Balance, December 31, 2001	$262	($2,057)	$449,111	$ -	$75,213	$7,496	$530,02
Net income	-	-	-	-	55,399	-	55,39
Net change in fair value of derivatives, net of tax benefit	-	-	-	-	-	(14,012)	(14,01
Effect of accounting treatment for swaps, net of taxes	-	-	-	-	-	1,748	1,74
Exercise of stock options	1	-	3,332	-	-	-	3,33
Tax benefit from stock option exercises	-	-	733	-	-	-	73
Issuance of treasury stock	-	351	-	-	(89)	-	26
Balance, December 31, 2002	263	(1,706)	453,176	-	130,523	(4,768)	577,4
Net income	-	-	-	-	134,470	-	134,4
Net change in fair value of derivatives, net of tax benefit	-	-	-	-	-	(6,356)	(6,35
Effect of accounting treatment for swaps, net of taxes	-	-	-	-	-	2,361	2,3
Exercise of stock options	1	-	1,441	-	-	-	1,4
Tax benefit from stock option exercises	-	-	774	-	-	-	7
Issuance of treasury stock	-	156	-	-	(58)	-	
Balance, December 31, 2003	264	(1,550)	455,391	-	264,935	(8,763)	710,2
Net income	-	-	-	-	134,903	-	134,9
Net change in fair value of derivatives, net of tax benefit	-	-	-	-	-	(525)	(52
Exercise of stock options	3	-	7,752	-	-	-	7,75
Tax benefit from stock option exercises	-	-	1,821	-	-	-	1,82
Issuance of restricted stock	-	-	1,514	(1,514)	-	-	-
Amortization of stock compensation expense	-	-	-	28	-	-	2
Issuance of treasury stock	-	88	-	-	(13)	-	7
Balance, December 31, 2004	$267	($1,462)	$466,478	($1,486)	$399,825	($9,288)	$854,33

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(Amounts in thousands of dollars)

	Year Ended December 31,		
	2004	**2003**	**2002**
Net income	$134,903	$134,470	$55,399
Other comprehensive income (loss):			
Net change in fair value of derivatives, net of taxes	(525)	(6,356)	(14,012)
Effect of change in accounting treatment for swaps, net of taxes	-	2,361	1,748
Other comprehensive loss	(525)	(3,995)	(12,264)
Comprehensive income	$134,378	$130,475	$43,135

The accompanying notes are an integral part of this statement.

NOTE 1 — ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Stone Energy is an independent oil and gas company engaged in the acquisition and subsequent exploration, development, and operation of oil and gas properties located in the conventional Gulf of Mexico (the "GOM") shelf, the deep shelf of the GOM, deepwater of the GOM and the Rocky Mountains. Our corporate headquarters are located at 625 E. Kaliste Saloom Road, Lafayette, Louisiana 70508. We have additional offices in New Orleans, Houston, and Denver.

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below.

Basis of Presentation:

The financial statements include our accounts and the accounts of our wholly owned subsidiary. All intercompany balances have been eliminated. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates:

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the 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. Estimates are used primarily when accounting for depreciation, depletion and amortization, unevaluated property costs, estimated future net cash flows from proved reserves, cost to abandon oil and gas properties, taxes, reserves of accounts receivable, accruals of capitalized costs, operating costs and production revenue, capitalized employee, general and administrative expenses, effectiveness of financial instruments, the purchase price allocation on properties acquired and contingencies.

Fair Value of Financial Instruments:

The fair value of cash and cash equivalents, accounts receivable, accounts payable to vendors and our variable-rate bank debt approximated book value at December 31, 2004 and 2003. Our hedging contracts, including puts, swaps and zero-premium collars, are recorded in the financial statements at fair value in accordance with the Financial Accounting Standards Board's ("FASB") Statement of Financial Accounting Standard ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." The carrying amount of our bank debt approximated fair value because the interest rate is variable and reflective of market rates. As of December 31, 2004 and 2003, the fair value of our $200,000 8¼% senior subordinated notes due 2011 was $216,500 and $218,000, respectively. As of December 31, 2004, the fair value of our $200,000 6¾% senior subordinated notes due 2014 was $198,500. The fair values of our outstanding notes were determined based upon quotes obtained from brokers.

Cash and Cash Equivalents:

We consider all money market funds and highly liquid investments in overnight securities through our commercial bank accounts, which result in available funds on the next business day, to be cash and cash equivalents.

Oil and Gas Properties:

We follow the full cost method of accounting for oil and gas properties. Under this method, all acquisition, exploration, development and estimated abandonment costs, including certain related employee and general and administrative costs (less any reimbursements for such costs) and interest incurred for the purpose of finding oil and gas are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Employee, general and administrative costs that are capitalized include salaries and all related fringe benefits paid to employees directly engaged in the acquisition, exploration and development of oil and gas properties, as well as all other directly identifiable general and administrative costs associated with such activities, such as rentals, utilities and insurance. Fees received from managed partnerships for providing such services are accounted for as a reduction of capitalized costs. During 2004, 2003 and 2002, we capitalized salaries, general and administrative costs (net of reimbursements) in the amount of $15,968, $14,179 and $10,520, respectively. Employee, general and administrative costs associated with production operations and general corporate activities are expensed in the period incurred. Additionally, workover and maintenance costs incurred solely to maintain or increase levels of production from an existing completion interval are charged to lease operating expense in the period incurred.

Generally accepted accounting principles allow the option of two acceptable methods for accounting for oil and gas properties. The successful efforts method is the allowable alternative to the full cost method. The primary differences between the two methods are in the treatment of exploration costs and in the computation of depreciation, depletion and amortization ("DD&A"). Under the full cost method, all exploratory costs are capitalized while under the successful efforts method exploratory costs associated with unsuccessful exploratory wells and all geological and geophysical costs are expensed. Under full cost accounting, DD&A is computed on cost centers represented by entire countries while under successful efforts cost centers are represented by properties, or some reasonable aggregation of properties with common geological structural features or stratigraphic condition, such as fields or reservoirs.

Under the full cost method of accounting, we are required to compare, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (based on period-end commodity prices and excluding cash flows related to estimated abandonment costs), net of related tax effect, to the net capitalized costs of proved oil and gas properties, including estimated capitalized abandonment costs, net of related deferred taxes. We refer to this comparison as a "ceiling test." If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows.

Transactions involving sales of unevaluated properties are recorded as adjustments to oil and gas properties and sales of reserves in place, unless extraordinarily large portions of reserves are involved, are recorded as adjustments to accumulated depreciation, depletion and amortization.

Effective January 1, 2003, management elected to change to the units of production ("UOP") method of amortizing proved oil and gas property costs from the previously used future gross revenue method. Under the UOP method, the quarterly provision for DD&A is computed by dividing production volumes, instead of revenues, for the period by the total proved reserves, instead of future gross revenues, as of the beginning of the period, and similarly applying the respective rate to the net cost of proved oil and gas properties, including future development costs. Management believes that this change in method is preferable because it removes fluctuations in DD&A expense caused by product pricing volatility within a reporting period and is a method more widely used in the oil and gas industry. As a result of the change in accounting principle, we recognized a cumulative transition adjustment of $4,031, net of tax, as a charge against our 2003 net income.

During the year ended December 31, 2002, our investment in oil and gas properties was amortized through DD&A using the future gross revenue method. The following table illustrates the effects that the change in accounting for DD&A would have had on our financial results for the year ended December 31, 2002 assuming adoption of the UOP method as of the beginning of the period:

	As Reported	Pro Forma (Unaudited)
Net income	$55,399	$49,768
Earnings per common share assuming dilution	$2.09	$1.88
DD&A per Mcfe	$1.52	$1.60

Oil and gas properties included $153,041 and $107,600 of unevaluated property and related costs that were not being amortized at December 31, 2004 and 2003, respectively. We believe that a majority of unevaluated properties at December 31, 2004 will be evaluated within 48 months. The excluded costs will be included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. Interest costs capitalized on unevaluated properties during the years ended December 31, 2004, 2003 and 2002 totaled $7,688, $8,577 and $8,519, respectively.

Asset Retirement Obligations:

On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." An asset retirement obligation (ARO) relates to the removal of facilities and tangible equipment at the end of a properties useful life. SFAS No. 143 requires that the fair value of a liability to retire an asset be recorded on the balance sheet and that the corresponding cost is capitalized in oil and gas properties. The ARO liability is accreted to its future value and the capitalized cost is depreciated consistent with the UOP method. See **Note 5 – Asset Retirement Obligations.**

Building and Land:

Building and land are recorded at cost. Our Lafayette office building is being depreciated on the straight-line method over its estimated useful life of 39 years.

NOTE 1 — ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Fixed Assets:

Fixed assets at December 31, 2004 and 2003 included approximately $3,467 and $3,603, respectively, of computer hardware and software costs, net of accumulated depreciation. These costs are being depreciated on the straight-line method over an estimated useful life of five years.

Other Assets:

Other assets at December 31, 2004 and 2003 included approximately $11,004 and $5,796, respectively, of deferred financing costs, net of accumulated amortization, related primarily to the issuance of the 8¼% notes, the 6¾% notes and the new credit facility (see **Note 7 – Long-Term Debt**). The costs associated with the 8¼% notes and 6¾% notes are being amortized over the life of the notes using a method that applies effective interest rates of 8.6% and 7.1%, respectively. The costs associated with the credit facility are being amortized on the straight-line method over the term of the facility.

Earnings Per Common Share:

Earnings per common share were calculated by dividing net income applicable to common stock by the weighted-average number of common shares outstanding during the year. Earnings per common share assuming dilution were calculated by dividing net income applicable to common stock by the weighted-average number of common shares outstanding during the year plus the weighted-average number of outstanding dilutive stock options and restricted stock granted to outside directors, officers and employees. There were approximately 315,000, 193,000 and 168,000 weighted-average dilutive shares for the years ending December 31, 2004, 2003 and 2002, respectively. Options that were considered antidilutive because the exercise price of the stock exceeded the average price for the applicable period totaled approximately 786,000, 1,021,000 and 1,064,000 shares during 2004, 2003 and 2002, respectively. During the years ended December 31, 2004, 2003 and 2002, approximately 278,000, 98,000 and 156,000 shares of common stock, respectively, were issued, from either authorized share or shares held in treasury, upon the exercise of stock options by employees and non-employee directors and awarding of employee bonus stock under the 2004 Amended and Restated Stock Incentive Plan.

Production Revenue:

Effective January 1, 2003, management elected to begin recognizing production revenue under the Entitlement method of accounting. Under this method, revenue is deferred for deliveries in excess of the company's net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. The cumulative effect of the adoption of the Entitlement method recognized in 2003 was immaterial.

Prior to adopting the Entitlement method, we recorded as revenue only that portion of production sold and allocable to our ownership interest in the related well. Any production proceeds received in excess of our ownership interest were reflected as a liability in the accompanying balance sheet. Revenue relating to net undelivered production to which we are entitled but for which we had not received payment were not recorded in the financial statements until such amounts were received. These amounts at December 31, 2002 were immaterial.

Income Taxes:

Income taxes are accounted for in accordance with the SFAS No. 109, "Accounting for Income Taxes." Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and gas properties for financial reporting purposes and income tax purposes. For financial reporting purposes, all exploratory and development expenditures, including future abandonment costs, related to evaluated projects are capitalized and depreciated, depleted and amortized on the UOP method. For income tax purposes, only the equipment and leasehold costs relative to successful wells are capitalized and recovered through depreciation or depletion. Generally, most other exploratory and development costs are charged to expense as incurred; however, we follow certain provisions of the Internal Revenue Code that allow capitalization of intangible drilling costs where management deems appropriate. Other financial and income tax reporting differences occur as a result of statutory depletion, different reporting methods for sales of oil and gas reserves in place, and different reporting methods used in the capitalization of employee, general and administrative and interest expenses.

New Accounting Standard:

On September 28, 2004, the SEC adopted Staff Accounting Bulletin ("SAB") No. 106, which expressed the its views regarding the application of SFAS No. 143 by oil and gas companies following the full cost accounting method. SAB No. 106 indicates that estimated dismantlement and abandonment costs that will be incurred as a result of future development activities on proved reserves are to be included in the estimated future cash flows in the full cost ceiling test. SAB No. 106 also indicates that these estimated costs are to be included in the costs to be amortized. We began applying SAB No. 106 prospectively in the third quarter of 2004.

NOTE 1 — ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Derivative Instruments and Hedging Activities:

Under SFAS No. 133, as amended, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in equity through other comprehensive income, net of related taxes, to the extent the hedge is effective. The cash settlement of effective cash flow hedges is recorded in oil and gas revenue. Instruments not qualifying for hedge accounting treatment are recorded in the balance sheet and changes in fair value are recognized in earnings as derivative expense (income). At December 31, 2004, our collar and swap contracts were considered effective cash flow hedges. (See **Note 9 – Hedging Activities**)

Stock-Based Compensation:

In October 1995, the FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation," which became effective with respect to us in 1996. Under SFAS No. 123, companies can either record expense based on the fair value of stock-based compensation upon issuance or elect to remain under the current Accounting Principles Board Opinion No. 25 ("APB 25") method whereby no compensation cost is recognized upon grant if certain requirements are met. We have continued to account for our stock-based compensation under APB 25.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure, an amendment of FASB Statement No. 123," to amend the disclosure requirements of SFAS No. 123 to require prominent disclosure in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effects of the method used on reported results. If the compensation expense for stock-based compensation plans had been determined consistent with the expense recognition provisions under SFAS No. 123, our net income and earnings per common share and earnings per common share assuming dilution for the years presented would have approximated the pro forma amounts below:

	Year Ended December 31,		
	2004	2003	2002
	(In thousands, except per share amounts) (Unaudited)		
Net income, as reported	$134,903	$134,470	$55,399
Add: Stock-based compensation expense included in net income, net of tax	67	-	-
Less: Stock-based compensation expense using fair value method, net of tax	(5,596)	(5,287)	(5,407)
Pro forma net income	$129,374	$129,183	$49,992
Earnings per common share	$5.07	$5.10	$2.10
Pro forma earnings per common share	4.87	4.90	1.90
Earnings per common share assuming dilution	$5.01	$5.07	$2.09
Pro forma earnings per common share assuming dilution	4.81	4.87	1.89

On December 16, 2004, the FASB issued SFAS No. 123 (revised 2004), *Share-Based Payment*, which is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*. SFAS No. 123(R) supersedes APB No. 25, *Accounting for Stock Issued to Employees*, and amends SFAS No. 95, *Statement of Cash Flows*. Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123; however, SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, be recognized in the income statement based on their fair values. Pro forma disclosure will no longer be an alternative.

SFAS No. 123(R) permits public companies to adopt its requirements using one of two methods:

1. the "modified prospective" method in which compensation cost is recognized beginning with the effective date (a) based on the requirements of Statement 123(R) for all share-based payments granted after the effective date and (b) based on the requirements of Statement 123 for all awards granted to employees prior to the effective date of Statement 123(R) that remain unvested on the effective date; or

2. the "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate based on the amounts previously recognized under Statement 123 for purposes of pro forma disclosures either (a) all prior periods presented or (b) prior interim periods of the year of adoption.

NOTE 1 — ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

SFAS No. 123(R) must be adopted no later than July 1, 2005. We expect to adopt SFAS No. 123(R) on July 1, 2005 using the modified prospective method. The Notes to Consolidated Financial Statement provide pro forma information assuming compensation expense for stock-based compensation plans had been determined consistent with the expense recognition provisions under SFAS No. 123. It is currently not known whether the implementation of this proposed Standard would result in financial results materially different from those presented above.

NOTE 2 — ACCOUNTS RECEIVABLE:

In our capacity as operator for our co-venturers, we incur drilling and other costs that we bill to the respective parties based on their working interests. We also receive payments for these billings and, in some cases, for billings in advance of incurring costs. Our accounts receivable are comprised of the following amounts:

	As of December 31,	
	2004	**2003**
Accounts Receivable:		
Other co-venturers	$11,187	$6,004
Trade	99,791	68,796
Officers and employees	12	4
Unbilled accounts receivable	408	262
	$111,398	$75,066

NOTE 3 — CONCENTRATIONS:

Sales to Major Customers

Our production is sold on month-to-month contracts at prevailing prices. We have attempted to diversify our sales and obtain credit protections such as parental guarantees from certain of our purchasers. The following table identifies customers from whom we derived 10% or more of our total oil and gas revenue during the following years ended:

	December 31,		
	2004	**2003**	**2002**
BP Energy Company	12%	(a)	(a)
Cinergy Marketing and Trading	11%	12%	-
Conoco, Inc.	13%	(a)	10%
Duke Energy Trading and Marketing LLC	(a)	13%	24%
Equiva Trading Company	11%	10%	(a)
Reliant Services, Inc.	-	-	11%
Total Gas & Power North America, Inc.	12%	-	-

(a) Less than 10 percent

We believe that the loss of any of these purchasers would not result in a material adverse effect on our ability to market future oil and gas production.

Production and Reserve Volumes

Approximately 89% (unaudited) of our estimated proved reserves at December 31, 2004 and 91% of our production during 2004 were associated with our Gulf Coast Basin properties.

Cash Deposits

Substantially all of our cash balances are in excess of federally insured limits.

NOTE 4 — INVESTMENT IN OIL AND GAS PROPERTIES:

The following table discloses certain financial data relative to our oil and gas producing activities located onshore and offshore the continental United States, which represents our only operating segment:

	Year Ended December 31,		
	2004	**2003**	**2002**
Oil and gas properties—			
Balance, beginning of year	$2,637,270	$2,224,960	$2,009,361
Costs incurred during the year:			
Capitalized—			
Acquisition costs, net of sales of unevaluated properties	201,550	54,456	14,071
Exploratory costs	151,571	175,864	86,063
Development costs	125,161	109,507	96,426
Salaries, general and administrative costs and interest	24,125	23,002	19,603
Less: overhead reimbursements	(469)	(247)	(564)
Asset retirement costs (1)	19,951	49,728	-
Total costs incurred during year	521,889	412,310	215,599
Balance, end of year	$3,159,159	$2,637,270	$2,224,960
Charged to expense—			
Lease operating expenses	$100,045	$72,786	$76,673
Production taxes	7,408	5,975	5,039
Accretion expense (1)	5,852	6,292	-
	$113,305	$85,053	$81,712
Unevaluated oil and gas properties—			
Costs incurred during year:			
Acquisition costs	$49,227	$25,891	$11,872
Exploration costs	23,438	3,843	6,238
	$72,665	$29,734	$18,110
Accumulated depreciation, depletion and amortization—			
Balance, beginning of year	($1,319,337)	($1,177,024)	($1,015,455)
Provision for DD&A (2)	(185,335)	(167,990)	(158,265)
Asset retirement costs (1)	-	32,354	-
Cumulative effect of change in accounting	-	(6,202)	-
Sale of proved properties	(11,948)	(475)	(3,304)
Balance, end of year	($1,516,620)	($1,319,337)	($1,177,024)
Net capitalized costs (proved and unevaluated)	$1,642,539	$1,317,933	$1,047,936
DD&A per Mcfe (2)	$2.10	$1.73	$1.52

(1) Recorded in accordance with SFAS No. 143. See **Note 5 – Asset Retirement Obligations**.
(2) DD&A during 2002 was computed on a method different than 2004 and 2003. See **Note 1 – Oil and Gas Properties**.

NOTE 4 — INVESTMENT IN OIL AND GAS PROPERTIES: (Continued)

The following table discloses financial data associated with unevaluated costs at December 31, 2004:

	Balance as of December 31, 2004	Costs incurred during the year ended December 31, 2004	2003	2002	2001 and prior
Acquisition costs	$129,603	$49,227	$14,654	$4,732	$60,990
Exploration costs	23,438	23,438	-	-	-
Total unevaluated costs	$153,041	$72,665	$14,654	$4,732	$60,990

We believe that substantially all of the costs not currently subject to amortization will be evaluated within four years.

NOTE 5 – ASSET RETIREMENT OBLIGATIONS:

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," effective for fiscal years beginning after June 15, 2002. This statement requires us to record the fair value of liabilities related to future asset retirement obligations ("ARO") in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of a property's useful life. We adopted SFAS No. 143 on January 1, 2003, which requires that the fair value of a liability to retire an asset be recorded on the balance sheet and that the corresponding cost is capitalized in oil and gas properties. The ARO liability is accreted to its future value and the capitalized cost is depreciated consistent with the UOP method. Upon adoption, we recognized a gain for a cumulative transition adjustment of $5,256, net of tax, computed from the components below:

Initial ARO as a liability on our consolidated balance sheet, including accumulated accretion	($76,270)
Increase in oil and gas properties for the cost to abandon our oil and gas properties	52,002
Accumulated depreciation on the additional capitalized costs included in oil and gas properties at adoption date	(19,922)
Reversal of accumulated depreciation previously recorded related to abandonment costs	52,276
Cumulative effect of adoption	8,086
Tax effect	(2,830)
Cumulative effect of adoption, net of tax effect	$5,256

In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO will be accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs will be depreciated on a UOP basis. As required by SFAS No. 143, our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

The change in our ARO during 2004 and 2003 is set forth below:

	2004	2003
Asset retirement obligation as of the beginning of the year	$80,288	$76,270
Liabilities incurred	27,173	7,017
Liabilities settled	(2,719)	(3,068)
Accretion expense	5,852	6,292
Revision of estimates	(4,503)	(6,223)
Asset retirement obligation as of the end of the year, including current portion	$106,091	$80,288

NOTE 5 – ASSET RETIREMENT OBLIGATIONS: (Continued)

Assuming adoption of SFAS No. 143 at the earliest period presented, our net income, diluted earnings per share and liability for asset retirement obligations as of the end of the year, without any cumulative effect of change in accounting principle, would have approximated the pro forma amounts below for the year ended and as of December 31, 2002:

	As Reported	Pro Forma (Unaudited)
Net income	$55,399	$54,881
Diluted earnings per share	$2.09	$2.07
Asset retirement obligations	$ -	$76,270

NOTE 6 — INCOME TAXES:

An analysis of our deferred taxes follows:

	As of December 31,	
	2004	2003
Net operating loss carryforward	$38,800	$33,312
Statutory depletion carryforward	5,302	5,000
Contribution carryforward	351	328
Capital loss carryforward	7	63
Alternative minimum tax credit carryforward	812	812
Temporary differences:		
Oil and gas properties — full cost	(248,020)	(170,218)
Hedges	5,001	4,719
Other	41	(1,152)
Valuation allowance	(358)	(391)
	($198,064)	($127,527)

For tax reporting purposes, operating loss carryforwards totaled approximately $110,857 at December 31, 2004. If not utilized, such carryforwards would begin expiring in 2009 and would completely expire by the year 2024. In addition, we had approximately $15,225 in statutory depletion deductions available for tax reporting purposes that may be carried forward indefinitely. Recognition of a deferred tax asset associated with these carryforwards is dependent upon our evaluation that it is more likely than not that the asset will ultimately be realized.

As of December 31, 2004 and 2003, a deferred tax asset of $7,267 and $3,408, respectively was included in other current assets.

Reconciliation between the statutory federal income tax rate and our effective income tax rate as a percentage of income before income taxes follows:

	Year Ended December 31,		
	2004	2003	2002
Income tax expense computed at the statutory federal income tax rate	35%	35%	35%
Other	-	-	-
Effective income tax rate	35%	35%	35%

Income tax expense allocated to accumulated other comprehensive income related to oil and gas hedges amounted to $282, $2,151 and $6,604 for the years ended December 31, 2004, 2003 and 2002, respectively.

In October 2004, the American Jobs Creation Act of 2004 ("the Act") was signed into law. The centerpiece of the Act is the domestic production incentive, which provides a tax deduction of up to nine percent (when fully phased-in) of the lesser of (1) qualified production activities income, or (2) taxable income (after the deduction for the utilization of net operating loss carryforwards). Effective January 1, 2005, the deduction is available to all taxpayers deriving income from qualified domestic production activities, including producers of oil and gas. In December 2004, the FASB issued FSP FAS 109-1, which provided guidance on the application of SFAS No. 109, Accounting for Income Taxes, to the provision within the Act that provides a tax deduction on qualified production activities. In FSP FAS 109-1, the FASB staff determined that because the qualified production activities deduction was contingent upon the future performance of specific activities, the deduction should be accounted for as a special deduction in accordance with SFAS No. 109.

NOTE 7 — LONG-TERM DEBT:

Long-term debt consisted of the following:

	As of December 31,	
	2004	2003
8¼% senior subordinated notes due 2011	$200,000	$200,000
6¾% senior subordinated notes due 2014	200,000	-
Bank debt	82,000	170,000
Total long-term debt	$482,000	$370,000

On April 30, 2004, we entered into a four-year $500,000 senior unsecured credit facility with a syndicated bank group. The new facility had an initial borrowing base of $425,000 and replaced the previous $350,000 credit facility. As a result, we recognized a charge for the early extinguishment of debt in the amount of $845, which relates to previously deferred financing costs associated with the old credit facility. The credit facility was amended on December 15, 2004 to allow for the issuance of the 6¾% senior subordinated notes and to adjust the borrowing base to $400,000. At December 31, 2004, we had $82,000 of borrowings outstanding with a weighted average interest rate of 3.8% under our bank credit facility. As of December 31, 2004, letters of credited totaling $13,084 had been issued under the credit facility, which reduce our availability for additional borrowings. These letters of credit have been issued in order to guarantee funding of plugging and abandonment obligations that were assumed through prior acquisitions of developed oil and gas properties.

The credit facility matures on April 30, 2008. At December 31, 2004, we had a borrowing base under the credit facility of $400,000, with availability of an additional $304,916 of borrowings. Interest rates are tied to LIBOR rates plus a margin that fluctuates based upon the ratio of aggregate outstanding borrowings and letters of credit exposure to the total borrowing base. Commitment fees are computed and payable quarterly at the rate of 50 basis points of borrowing availability. The borrowing base limitation is re-determined periodically and is based on a borrowing base amount established by the banks for our oil and gas properties.

Under the financial covenants of our credit facility, we must (i) maintain a ratio of consolidated debt to consolidated EBITDA, as defined in the amended credit agreement, for the preceding four quarterly periods of not greater than 3.25 to 1 and (ii) maintain a consolidated tangible net worth of a least $599,000 as of December 31, 2003, which is adjusted for future earnings and cash proceeds from equity offerings. In addition, the credit facility places certain customary restrictions or requirements with respect to disposition of properties, incurrence of additional debt, change of ownership and reporting responsibilities. These covenants may limit or prohibit us from paying cash dividends.

On December 15, 2004, we issued $200,000 6¾% senior subordinated notes due 2014. The notes were sold at par value and we received net proceeds of $195,500 and are subordinated to our senior unsecured credit facility and rank *pari passu* with our 8¼% senior subordinated notes. There is no sinking fund requirement and the notes are redeemable at our option, in whole but not in part, at any time before December 15, 2009 at a Make-Whole Amount. Beginning December 15, 2009, the notes are redeemable at our option, in whole or in part, at 103.375% of their principal amount and thereafter at prices declining annually to 100% on and after December 15, 2012. In addition, before December 15, 2007, we may redeem up to 35% of the aggregate principal amount of the notes issued with net proceeds from an equity offering at 106.75%. The notes provide for certain covenants, which include, without limitation, restrictions on liens, indebtedness, asset sales, dividend payments and other restricted payments. At December 31, 2004, $592 had been accrued in connection with the June 15, 2005 interest payment.

On December 5, 2001, we issued $200,000 8¼% senior subordinated notes due 2011. The notes were sold at par value and we received net proceeds of $195,500 and are subordinated to our senior unsecured credit facility and rank *pari passu* with our 6¾% senior subordinated notes. There is no sinking fund requirement and the notes are redeemable at our option, in whole but not in part, at any time before December 15, 2006 at a Make-Whole Amount. Beginning December 15, 2006, the notes are redeemable at our option, in whole or in part, at 104.125% of their principal amount and thereafter at prices declining annually to 100% on and after December 15, 2009. In addition, before December 15, 2004, we may redeem up to 35% of the aggregate principal amount of the notes issued with net proceeds from an equity offering at 108.25%. The notes provide for certain covenants, which include, without limitation, restrictions on liens, indebtedness, asset sales, dividend payments and other restricted payments. At December 31, 2004, $721 had been accrued in connection with the June 15, 2005 interest payment.

On September 30, 2003, we redeemed our $100,000 outstanding 8¾% senior subordinated notes due 2007 at a call premium of 102.917%. The cash redemption payment was funded through a combination of available cash and $90,000 of borrowings under our bank credit facility. We recorded a pre-tax charge of $4,661 during 2003 for the early extinguishment of debt, which related to the call premium of $2,917 and the recognition of previously deferred financing costs and unamortized discounts associated with the issuance of the notes in 1997.

NOTE 8 — TRANSACTIONS WITH RELATED PARTIES:

James H. Stone, our chairman of the board of directors, owns up to 7.5% of the working interest in certain wells drilled on Section 19 on the east flank of the Weeks Island Field. This interest was acquired prior to our initial public offering in 1993. In his capacity as a working interest owner, he is required to pay his proportional share of all costs and is entitled to receive his proportional share of revenue.

Our interests in certain oil and gas properties are burdened by net profits interests and overriding royalty interests granted at the time of acquisition to certain of our officers. Such net profit interest owners do not receive any cash distributions until we have recovered all acquisition, development, financing and operating costs. D. Peter Canty, a director and former President and Chief Executive Officer, and James H. Prince, Executive Vice President and Chief Financial Officer, remain net profit interest owners. Amounts paid to these officers under the remaining net profits arrangement amounted to $727, $1,169 and $934 in 2004, 2003 and 2002, respectively. In addition, Michael E. Madden, our Vice President of Exploration and Production Technology, was granted an overriding royalty interest in some of our properties by an independent third party. At the time he was granted this interest, he was serving Stone as an independent engineering consultant. The amount paid to Michael E. Madden during 2004, 2003 and 2002 under the overriding royalty arrangement totaled $101, $94 and $61, respectively.

Pursuant to his retirement, we agreed to a consulting arrangement with Mr. Canty whereby he was paid $235 for consulting services for the period from April 1, 2004 through December 31, 2004. There is no agreement for consulting service with Mr. Canty for the year ended December 31, 2005.

The son of John P. Laborde, one of our directors, has an interest in several marine service companies, which provided services to us during 2004, 2003 and 2002 in the amount of $1,534, $2,978 and $1,717, respectively. As of December 31, 2004 and 2003, we had accrued $293 and $155, respectively, in accounts payable to vendors for invoices received from these companies but not yet paid. John P. Laborde has no interest in these companies.

The law firm of Gordon, Arata, McCollam, Duplantis and Eagan, of which B.J. Duplantis, one of our directors, is a senior partner, provided legal services for us during 2002. The value of these services totaled approximately $14 during 2002.

NOTE 9 — HEDGING ACTIVITIES:

We enter into hedging transactions to secure a price for a portion of future production that is acceptable at the time at which the transaction is entered. The primary objective of these activities is to reduce our exposure to the possibility of declining oil and gas prices during the term of the hedge. These hedges are designated as cash flow hedges upon entered into the contract. We do not enter into hedging transactions for trading purposes. Monthly settlements of these contracts are reflected in revenue from oil and gas production. Under generally accepted accounting principles, in order to consider these futures contracts as hedges, (i) we must designate the futures contract as a hedge of future production and (ii) the contract must be effective at reducing our exposure to the risk of changes in prices. Changes in the market values of futures contracts treated as hedges are not recognized in income until the hedged item is also recognized in income. If the above criteria are not met, we will record the market value of the contract at the end of each month and recognize a related increase or decrease in derivative expenses (income).

Stone has entered into zero-premium collars with various counterparties for a portion of our expected 2005 oil and natural gas production from the Gulf Coast Basin. The natural gas collar settlements are based on an average of New York Mercantile Exchange ("NYMEX") prices for the last three days of a respective month. The oil collar settlements are based upon an average of the NYMEX closing price for West Texas Intermediate ("WTI") during the entire calendar month. The contracts require payments to the counterparties if the average price is above the ceiling price or payment from the counterparties if the average price is below the floor price. At December 31, 2004, our open gas collars were reflected as an asset at fair value of $58 and our oil collars were reflected as liabilities at a fair value of $2,694. Our collars are with Bank of America, N.A., Bank of Montreal, Goldman Sachs and JP Morgan. Our collar contracts are considered effective hedges under SFAS No. 133 and all changes in fair value are recorded, net of taxes, in other comprehensive income prior to settlement.

In addition to collar contracts, we utilized fixed-price swaps to hedge a portion of our future gas production from our Rocky Mountains properties. Our swap contracts are with Bank of America and are based upon Inside FERC published prices for natural gas deliveries at Kern River. Swaps typically provide for monthly payments by us if prices rise above the swap price or to us if prices fall below the swap price. At December 31, 2004, our swap contracts were considered effective hedges and reflected as liabilities at fair value of $11,652.

During 2004 and 2003, a portion of our oil and natural gas production from the Gulf Coast Basin was hedged with put contracts. Put contracts are purchased at a rate per unit of hedged production that fluctuates with the commodity futures market. The historical cost of the put contracts represents our maximum cash exposure. We are not obligated to make any further payments under the put contracts regardless of future commodity price fluctuations. Under put contracts, monthly payments are made to us if NYMEX prices fall below the agreed upon floor price, while allowing us to fully participate in commodity prices above that floor.

NOTE 9 — HEDGING ACTIVITIES: (Continued)

At December 31, 2004, we had an accumulated other comprehensive loss of $9,288, net of tax, of which $7,574 related to our gas swap contracts and the remainder related to our collar contracts.

In October 2002, we reached an agreement with Enron North America Corp. to purchase the portion of our fixed price natural gas swap contract settling subsequent to October 2002 for $5,917. We amortized $3,632 of derivative expenses during 2003 related to the balance of previously recorded other comprehensive loss from the swap contract.

The following table shows our hedging positions as of March 3, 2005:

	Zero-Premium Collars					
	Natural Gas			Oil		
	Daily Volume (MMBtus/d)	Floor Price	Ceiling Price	Daily Volume (Bbls/d)	Floor Price	Ceiling Price
2005	20,000	$4.50	$10.25	4,000	$28.00	$52.90
2005	20,000	4.00	13.50	4,000	28.00	52.75
2005	10,000	5.00	10.00	-	-	-
2005	10,000 (1)	5.00	10.85	-	-	-
2005	10,000 (1)	5.50	10.80	-	-	-

	Fixed Price Gas Swaps	
	Daily Volume (MMBtus/d)	Price (2)
2005	15,000	$3.42

(1) Contract hedges production from April to December 2005.
(2) Based upon Inside FERC published prices for natural gas deliveries at Kern River.

During 2004, 2003 and 2002, we recognized $4,099, $8,711 and $15,968, respectively, of derivative expenses. The components of derivative expenses were as follows:

	Year Ended December 31,		
	2004	2003	2002
Cost of put contracts settled	$4,099	$5,079	$13,175
Change in fair value of ineffective swap	-	-	104
Amortization of other comprehensive loss for ineffective swap	-	3,632	2,689
Total derivative expense	$4,099	$8,711	$15,968

For the years ended December 31, 2004, 2003 and 2002, we realized net increases (decreases) in oil and gas revenue related to hedging transactions of ($10,122), ($1,576) and $5,953, respectively.

NOTE 11 — COMMITMENTS AND CONTINGENCIES:

We lease office facilities in New Orleans, Louisiana, Houston, Texas and two locations in Denver, Colorado under the terms of long-term, non-cancelable leases expiring on various dates through 2006. We also lease automobiles under the terms of non-cancelable leases expiring at various dates through 2006. The minimum net annual commitments under all leases, subleases and contracts noted above at December 31, 2004 were as follows:

2005	619
2006	141

Payments related to our lease obligations for the years ended December 31, 2004, 2003 and 2002 were approximately $1,122, $1,140 and $889, respectively. We sublease office space to third parties, and for the years ended 2004, 2003 and 2002, we recorded related receipts of $832, $816 and $239, respectively. A minimum lease rental to be received from the sublease of office space is $77 for the year ended December 31, 2005.

NOTE 11 — COMMITMENTS AND CONTINGENCIES: *(Continued)*

We are contingently liable to surety insurance companies in the aggregate amount of $73,795 relative to bonds issued on our behalf to the United States Department of the Interior Minerals Management Service (MMS), federal and state agencies and certain third parties from which we purchased oil and gas working interests. The bonds represent guarantees by the surety insurance companies that we will operate in accordance with applicable rules and regulations and perform certain plugging and abandonment obligations as specified by applicable working interest purchase and sale agreements.

We are also named as a defendant in certain lawsuits and are a party to certain regulatory proceedings arising in the ordinary course of business. We do not expect these matters, individually or in the aggregate, will have a material adverse effect on our financial condition.

OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. Under OPA and a final rule adopted by the MMS in August 1998, responsible parties of covered offshore facilities that have a worst case oil spill of more than 1,000 barrels must demonstrate financial responsibility in amounts ranging from at least $10,000 in specified state waters to at least $35,000 in OCS waters, with higher amounts of up to $150,000 in certain limited circumstances where the MMS believes such a level is justified by the risks posed by the operations, or if the worst case oil-spill discharge volume possible at the facility may exceed the applicable threshold volumes specified under the MMS's final rule. We do not anticipate that we will experience any difficulty in continuing to satisfy the MMS's requirements for demonstrating financial responsibility under OPA and the MMS's regulations.

We have recently entered into an exploration agreement with Kerr-McGee Oil and Gas Corp. covering several undeveloped leases in the Gulf of Mexico. Under the agreement, we acquired varying interests in these deep water and deep shelf leases and have agreed to participate in five commitment wells to be drilled by the end of 2005. As of December 31, 2004, we estimate our portion of cost associated with this agreement to be $42,187 for 2005. In addition, we also intend to evaluate additional drilling opportunities on the respective leases through 2006.

In connection with our exploration efforts, specifically in the deep water of the Gulf of Mexico, we have committed to acquire seismic data from certain providers on multiple offshore blocks over the next three years. As of December 31, 2004, our seismic data purchase commitments totaled $41,646 to be incurred over the next three years.

NOTE 12 — EMPLOYEE BENEFIT PLANS:

We have entered into deferred compensation and disability agreements with certain of our officers whereby we have purchased split-dollar life insurance policies to provide certain retirement and death benefits for certain of our officers and death benefits payable to us. The aggregate death benefit of the policies was $3,221 at December 31, 2004, of which $1,678 was payable to certain officers or their beneficiaries and $1,543 was payable to us. Total cash surrender value of the policies, net of related surrender charges at December 31, 2004, was approximately $1,085 and is recorded in other long-term assets. Additionally, the benefits under the deferred compensation agreements vest after certain periods of employment, and at December 31, 2004, the liability for such vested benefits was approximately $790 and is recorded in other long-term liabilities.

The following is a brief description of each incentive compensation plans applicable to our employees:

i. The Annual Incentive Compensation Plan provided for an annual cash incentive bonus that ties incentives to the annual return on our common stock, to a comparison of the price performance of our common stock to the average quarterly returns on the shares of stock of a peer group of companies with which we compete and to the growth in our net earnings per share, net cash flows and net asset value. Incentive bonuses are awarded to participants based upon individual performance factors. Stone incurred expense of $851, net of amounts capitalized, for the year ended December 31, 2002 related to incentive compensation bonuses paid under this plan. This plan was terminated upon the approval and adoption of the Revised Annual Incentive Compensation Plan, discussed below.

   In February 2003, our board of directors approved and adopted the Revised Annual Incentive Compensation Plan. The revised plan provides for annual cash incentive bonuses that are tied to the achievement of certain strategic objectives as defined by our board of directors on an annual basis. Stone incurred expense of $2,318 and $2,636, net of amounts capitalized, for each of the years ended December 31, 2004 and 2003, respectively, related to incentive compensation bonuses to be paid under the revised plan.

NOTE 12 — EMPLOYEE BENEFIT PLANS: (Continued)

ii. At the 2004 Annual Meeting of Stockholders, the stockholders approved the 2004 Amended and Restated Stock Incentive Plan (the "Plan"), which provides for the granting of incentive stock options, restricted stock awards, bonus stock awards, or any combination as is best suited to the circumstances of the particular employee or nonemployee director. The Plan provides for 4,225,000 shares of common stock to be reserved for issuance pursuant to this plan. At the 2003 Annual Meeting of Stockholders, the stockholders approved, through proxy voting, an amendment that increased the aggregate number of shares of Common Stock reserved for issuance by 1,000,000 shares. Under the Plan, we may grant both incentive stock options qualifying under Section 422 of the Internal Revenue Code and options that are not qualified as incentive stock options to all employees and directors. All such options must have an exercise price of not less than the fair market value of the common stock on the date of grant and may not be re-priced without stockholder approval. Stock options to all employees vest ratably over a five-year service-vesting period and expire ten years subsequent to award. Stock options issued to non-employee directors vest ratably over a three-year service-vesting period and expire ten years subsequent to award. In addition, the Plan provides that shares available under the Plan may be granted as restricted stock.

iii. The Stone Energy 401(k) Profit Sharing Plan provides eligible employees with the option to defer receipt of a portion of their compensation and we may, at our discretion, match a portion or all of the employee's deferral. The amounts held under the plan are invested in various investment funds maintained by a third party in accordance with the directions of each employee. An employee is 20% vested in matching contributions (if any) for each year of service and is fully vested upon five years of service. For the years ended December 31, 2004, 2003 and 2002, Stone contributed $850, $677 and $645, respectively, to the plan.

iv. The Stone Energy Corporation Deferred Compensation Plan provides eligible executives with the option to defer up to 100% of their compensation for a calendar year and we may, at our discretion, match a portion or all of the participant's deferral based upon a percentage determined by the board of directors. The amounts held under the plan are invested in various investment funds maintained by a third party in accordance with the direction of each participant. During the year ended December 31, 2004, there were no matching contributions made by Stone as the Plan became effective December 1, 2004.

Stock Options. A summary of stock options as of December 31, 2004, 2003 and 2002 and changes during the years ended on those dates is presented below.

	Year Ended December 31,					
	2004		2003		2002	
	Number of Options	Wgtd. Avg. Exer. Price	Number of Options	Wgtd. Avg. Exer. Price	Number of Options	Wgtd. Avg. Exer. Price
Outstanding at beginning of year....	2,735,559	$37.92	2,419,557	$37.68	2,058,531	$38.04
Granted	282,250	46.16	571,600	36.63	625,500	34.23
Exercised	(296,107)	29.34	(127,600)	21.20	(160,582)	24.55
Forfeited	(180,567)	42.97	(127,998)	44.42	(103,892)	44.35
Expired	-	-	-	-	-	-
Outstanding at end of year.............	2,541,135	$39.47	2,735,559	$37.92	2,419,557	$37.68
Options exercisable at year-end......	1,372,416	38.79	1,292,239	36.39	1,082,536	32.77
Weighted average fair value of options granted during the year ...	$20.12		$16.57		$16.12	

The fair value of each stock option granted was estimated as of the date of grant the Black-Scholes option-pricing model with the following assumptions:

	2004	2003	2002
Dividend yield	-	-	-
Expected volatility..........	39.92%	41.89%	45.10%
Risk-free interest rate	3.90%	3.66%	3.11%
Expected option life (1)..........	6.0 Years	6.0 Years	6.0 Years

(1) The expected life of options granted to nonemployee directors was assumed to be four years.

NOTE 12 — EMPLOYEE BENEFIT PLANS: (Continued)

The following table summarizes information regarding stock options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Options Outstanding at 12/31/04	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable at 12/31/04	Wgtd. Avg. Exercise Price
$9 – $20	71,000	0.7 years	$12.09	71,000	$12.09
20 – 30	268,500	2.3 years	23.90	268,500	23.90
30 – 40	1,271,778	7.5 years	35.54	528,658	35.55
40 – 50	436,183	7.1 years	45.55	120,364	44.79
50 – 70	493,674	4.8 years	56.63	383,894	56.74
	2,541,135	6.2 years	39.47	1,372,416	38.79

Common stock issued upon the exercise of non-qualified stock options results in a tax deduction for us equivalent to the compensation income recognized by the option holder. For financial reporting purposes, the tax effect of this deduction is accounted for as a credit to additional paid-in capital rather than as a reduction of income tax expense. The exercise of stock options during 2004, 2003 and 2002 resulted in a tax benefit to us of approximately $1,821, $774 and $733, respectively.

At December 31, 2004, we had approximately 766,607 additional shares available for issuance pursuant to the 2004 Amended and Restated Stock Incentive Plan (the "Plan"). As discussed below, the Plan provide for the issuance of restricted shares. Any such issuance would reduce the number of shares available for future grants of stock options, restricted stock and stock bonus awards.

Restricted Stock. In addition, the Plan provides that shares available for issuance may be granted as restricted stock. In accordance with APB No. 25, we record unearned compensation in connection with the granting of restricted stock equal to the fair value of our common stock on the date of grant. As the restrictions lapse, we reduce unearned compensation and recognize compensation expense. During 2004, the Company granted 33,710 shares of restricted stock with a weighted average grant date fair value of $44.91 per share, and recognized compensation expense of $28 related to these shares. There were no shares of restricted stock granted during 2003 and 2002 under the Plan.

NOTE 13 — SUBSEQUENT EVENTS:

On March 1, 2005, we completed the acquisition of approximately 35,000 net exploratory acres in the Williston Basin of North Dakota and Montana. The acquisition cost, net of purchase price adjustments, totaled approximately $85,707, of which $9,000 was funded in cash as a prepayment during December 2004 and is included in other assets as of December 31, 2004. The remaining purchase price was financed with borrowings under Stone's bank credit facility. Approximately 75% of the net purchase price has been allocated to unevaluated costs. We expect to begin exploring the acreage with a multi-well drilling program beginning in 2005.

NOTE 14 — OIL AND GAS RESERVE INFORMATION – UNAUDITED:

Our net proved oil and gas reserves at December 31, 2004 have been estimated by independent petroleum consultants in accordance with guidelines established by the SEC. Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. In addition, the present values should not be construed as the market value of the oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

The following table sets forth an analysis of the estimated quantities of net proved and proved developed oil (including condensate) and natural gas reserves, all of which are located onshore and offshore the continental United States:

	Oil in MBbls	Natural Gas in MMcf
Proved reserves as of December 31, 2001	55,391	442,669
Revisions of previous estimates	905	2,378
Extensions, discoveries and other additions	2,101	59,785
Purchase of producing properties	188	240
Sale of reserves	(329)	(726)
Production (1)	(6,237)	(65,694)
Proved reserves as of December 31, 2002	52,019	438,652
Revisions of previous estimates	317	(12,233)
Extensions, discoveries and other additions	8,893	86,821
Purchase of producing properties	3,731	10,647
Sale of reserves	(71)	(28)
Production	(5,727)	(62,536)
Proved reserves as of December 31, 2003	59,162	461,323
Revisions of previous estimates	(2,297)	(37,077)
Extensions, discoveries and other additions	3,988	74,024
Purchase of producing properties	1,854	48,590
Sale of reserves	(709)	(5,726)
Production	(5,438)	(55,544)
Proved reserves as of December 31, 2004	56,560	485,590
Proved developed reserves:		
as of December 31, 2002	39,772	334,692
as of December 31, 2003	45,128	339,664
as of December 31, 2004	42,152	352,748

(1) Excludes gas production volumes related to the volumetric production payment.

NOTE 14 — OIL AND GAS RESERVE INFORMATION – UNAUDITED: (Continued)

The following tables present the standardized measure of future net cash flows related to proved oil and gas reserves together with changes therein, as defined by the FASB, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2004 in accordance with SFAS No. 143. You should not assume that the future net cash flows or the discounted future net cash flows, referred to in the table below, represent the fair value of our estimated oil and gas reserves. As required by the SEC, we determine estimated future net cash flows using period-end market prices for oil and gas without considering hedge contracts in place at the end of the period. The average 2004 year-end product prices for all of our properties were $41.14 per barrel of oil and $6.58 per Mcf of gas. Future production and development costs are based on current costs with no escalations. Estimated future cash flows net of future income taxes have been discounted to their present values based on a 10% annual discount rate.

	Standardized Measure Year Ended December 31,		
	2004	2003	2002
Future cash inflows	$5,520,235	$4,788,471	$3,713,318
Future production costs	(965,488)	(682,970)	(581,539)
Future development costs	(608,824)	(472,193)	(414,518)
Future income taxes	(1,044,509)	(969,394)	(645,160)
Future net cash flows	2,901,414	2,663,914	2,072,101
10% annual discount	(971,683)	(867,991)	(697,391)
Standardized measure of discounted future net cash flows	$1,929,731	$1,795,923	$1,374,710

	Changes in Standardized Measure Year Ended December 31,		
	2004	2003	2002
Standardized measure at beginning of year	$1,795,923	$1,374,710	$908,576
Sales and transfers of oil and gas produced, net of production costs	(436,748)	(429,544)	(289,830)
Changes in price, net of future production costs	235,626	380,812	862,253
Extensions and discoveries, net of future production and development costs	263,479	505,213	240,056
Changes in estimated future development costs, net of development costs incurred during the period	13,596	11,477	(43,607)
Revisions of quantity estimates	(183,973)	(59,663)	22,146
Accretion of discount	238,026	178,476	103,880
Net change in income taxes	(41,027)	(174,286)	(279,829)
Purchases of reserves in-place	247,208	104,957	3,374
Sales of reserves in-place	(19,558)	(622)	(1,403)
Changes in production rates due to timing and other	(182,821)	(95,607)	(150,906)
Net increase (decrease) in standardized measure	133,808	421,213	466,134
Standardized measure at end of year	$1,929,731	$1,795,923	$1,374,710

NOTE 15 — SUMMARIZED QUARTERLY FINANCIAL INFORMATION – UNAUDITED:

	Three Months Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
	(amounts in thousands, except per share amounts)			
2004				
Operating revenue	$133,580	$142,224	$128,306	$140,091
Income from operations	58,335	60,899	42,744	60,037
Net income	35,773	35,903	25,565	37,662
Earnings common per share	$1.35	$1.35	$0.96	$1.41
Earnings common per share assuming dilution	1.33	1.33	0.95	1.40
2003				
Operating revenue	$157,546	$117,212	$115,993	$117,554
Income from operations	88,901	48,512	44,289	44,488
Income before cumulative effects of accounting changes	54,633	28,627	22,767	27,218
Net income	55,858	28,627	22,767	27,218
Income before cumulative effects of accounting changes	$2.07	$1.09	$0.86	$1.03
Cumulative effects of accounting changes	0.05	-	-	-
Earnings common per share	$2.12	$1.09	$0.86	$1.03
Income before cumulative effects of accounting changes	$2.06	$1.08	$0.86	$1.02
Cumulative effects of accounting changes	0.05	-	-	-
Earnings common per share assuming dilution	$2.11	$1.08	$0.86	$1.02

GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below shall apply to the indicated terms as used in this Form 10-K. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Active property. An oil and gas property with existing production.

BBtu. One billion Btus.

Bcf. One billion cubic feet of gas.

Bcfe. One billion cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six mcf of natural gas.

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

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

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.

Exploratory well. A well drilled to find and produce oil or gas reserves not classified as proved, 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.

Gross acreage or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

LIBOR. Represents the London Inter-Bank Offering Rate of interest.

Liquidity. The ability to obtain cash quickly either through the conversion of assets or the incurrence of liabilities.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of gas.

Mcfe. One thousand cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six mcf of natural gas.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million Btus.

MMcf. One million cubic feet of gas.

MMcfe. One million cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six mcf of natural gas.

MMcfe/d. One million cubic feet of gas equivalent per day.

Make-Whole Amount. The greater of 104.125% of the principal amount of the 8¼% Notes and the sum of the present values of the remaining scheduled payments of principal and interest discounted to the date of redemption on a semiannual basis at the applicable treasury rate plus 50 basis points.

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

Net profits interest. An interest in an oil and gas property entitling the owner to a share of oil or gas production subject to production costs.

GLOSSARY OF CERTAIN INDUSTRY TERMS: (Continued)

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

Pari Passu. The term is Latin and translates to "without partiality." Commonly refers to two securities or obligations having equal rights to payment.

Primary term lease. An oil and gas property with no existing production, in which Stone has a specific time frame to establish production without losing the rights to explore the property.

Production payment. An obligation of the purchaser of a property to pay a specified portion of future gross revenues, less related production taxes and transportation costs, to the seller of the property.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

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

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

Proved 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.

Standardized measure of discounted future net cash flows. The standardized measure represents value-based information about an enterprise's proved oil and gas reserves based on estimates of future cash flows, including income taxes, from production of proved reserves assuming continuation of year-end economic and operating conditions.

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 whether such acreage contains proved reserves.

Volumetric production payment. An obligation of the purchaser of a property to deliver a specific volume of production, free and clear of all costs, to the seller of the property.

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

EXHIBIT INDEX

Exhibit Number		Description
3.1	--	Certificate of Incorporation of the Registrant, as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).
3.2	--	Restated Bylaws of the Registrant (incorporated by reference to Exhibit 3.2 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).
3.3	--	Certificate of Amendment of the Certificate of Incorporation of Stone Energy Corporation, dated February 1, 2001 (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K, filed February 7, 2001).
3.4	--	Amendment to restated Bylaws of the Registrant (incorporated by reference to Exhibit 3.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 001-12074)).
4.1	--	Rights Agreement, with exhibits A, B and C thereto, dated as of October 15, 1998, between Stone Energy Corporation and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A (File No. 001-12074)).
4.2	--	Amendment No. 1, dated as of October 28, 2000, to Rights Agreement dated as of October 15, 1998, between Stone Energy Corporation and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-4 (Registration No. 333-51968)).
4.3	--	Indenture between Stone Energy Corporation and JPMorgan Chase Bank dated December 10, 2001 (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-4 (Registration No. 333-81380)).
4.4	--	Indenture between Stone Energy Corporation and JPMorgan Chase Bank, National Association, as trustee, dated December 15, 2004 (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on December 15, 2004.)
†*4.5	--	Stone Energy Corporation Deferred Compensation Plan
†*4.6	--	Adoption Agreement between Fidelity Management Trust Company and Stone Energy Corporation for the Stone Energy Corporation Deferred Compensation Plan dated December 1, 2004.
†10.1	--	Deferred Compensation and Disability Agreements between TSPC and D. Peter Canty dated July 16, 1981, and between TSPC and James H. Prince dated August 23, 1981 and September 20, 1981, respectively (incorporated by reference to Exhibit 10.8 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).
†10.2	--	Conveyances of Net Profits Interests in certain properties to D. Peter Canty and James H. Prince (incorporated by reference to Exhibit 10.9 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).
†10.3	--	Deferred Compensation and Disability Agreement between TSPC and E. J. Louviere dated July 16, 1981 (incorporated by reference to Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1995 (File No. 001-12074)).
†10.4	--	Stone Energy Corporation Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.14 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1993 (File No. 001-12074)).

†10.5 -- Stone Energy Corporation Amendment to the Annual Incentive Compensation Plan dated January 15, 1997 (incorporated by reference to Exhibit 10.9 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 001-12074)).

†10.6 -- Stone Energy Corporation Revised Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 001-12074)).

†10.7 -- Stone Energy Corporation 2001 Amended and Restated Stock Option Plan (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-8 (Registration No. 333-107440)).

10.8 -- Credit Agreement between the Registrant, the financial institutions named therein and Bank of America, N.A., as administrative agent, dated April 30, 2004. (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q, filed August 9, 2004 (File No. 001-12074)).

*10.9-- Amendment No. 1 to the Credit Agreement between the Registrant, the financial institutions named therein and Bank of America, N.A., as administrative agent, dated December 14, 2004.

†10.10 -- Stone Energy Corporation 2004 Amended and Restated Stock Incentive Plan (incorporated by reference to the Registrant's Registration Statement on Form S-8 (Registration No. 333-107440)).

†*10.11 -- Stone Energy Corporation Revised (2005) Incentive Compensation Plan.

16.1 -- Letter of Arthur Andersen LLP, dated June 26, 2002, regarding change in certifying accountant (incorporated by reference to Exhibit 16.1 to the Registrant's Form 8-K, filed June 27, 2002 (File No. 001-12074)).

18.1 -- Letter of Ernst & Young LLP, dated May 13, 2003, regarding change in accounting principles (incorporated by reference to Exhibit 18.1 to the Registrant's Quarterly Report on Form 10-Q, for the period ended March 31, 2003 (File No. 001-12074)).

*21.1 -- Subsidiaries of the Registrant.

*23.1 -- Consent of Independent Registered Public Accounting Firm.

*23.2 -- Consent of Atwater Consultants, Ltd.

*23.3 -- Consent of Cawley, Gillespie & Associates, Inc.

*23.4 -- Consent of Netherland, Sewell & Associates, Inc.

*23.5 -- Consent of Ryder Scott Company, L.P.

*31.1 -- Certification of Principal Executive Officer of Stone Energy Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.

*31.2 -- Certification of Principal Financial Officer of Stone Energy Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.

*#32.1 -- Certification of Chief Executive Officer and Chief Financial Officer of Stone Energy Corporation pursuant to 18 U.S.C. § 1350.

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* Filed herewith.

† Identifies management contracts and compensatory plans or arrangements.

\# Not considered to be "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

Senior Management

Andrew L. Gates, III
Senior Vice President, General Counsel and Secretary

Craig L. Glassinger
Executive Vice President—Business Development

E. J. Louviere
Senior Vice President—Land

Michael E. Madden
Vice President—Exploration and Production Technology

J. Kent Pierret
Senior Vice President, Chief Accounting Officer and Treasurer

James H. Prince
Executive Vice President and Chief Financial Officer

Jerome F. Wenzel
Vice President—Production and Drilling

Gerald G. Yunker
Senior Vice President—Exploitation

Florence M. Ziegler
Vice President—Human Resources

Corporate Information

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New Orleans, Louisiana
70139-9869

Annual Meeting
The Company's Annual Meeting of Stockholders will be held at 10:00 a.m. on May 18, 2005, in the Denechaud Room of the Le Pavillion Hotel, New Orleans, Louisiana.

Form 10-K
Copies of the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained upon request to Investor Relations or through the Company's website at www.StoneEnergy.com. Quarterly reports and press release information also may be accessed through the website.

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