STONE ENERGY CORPORATION

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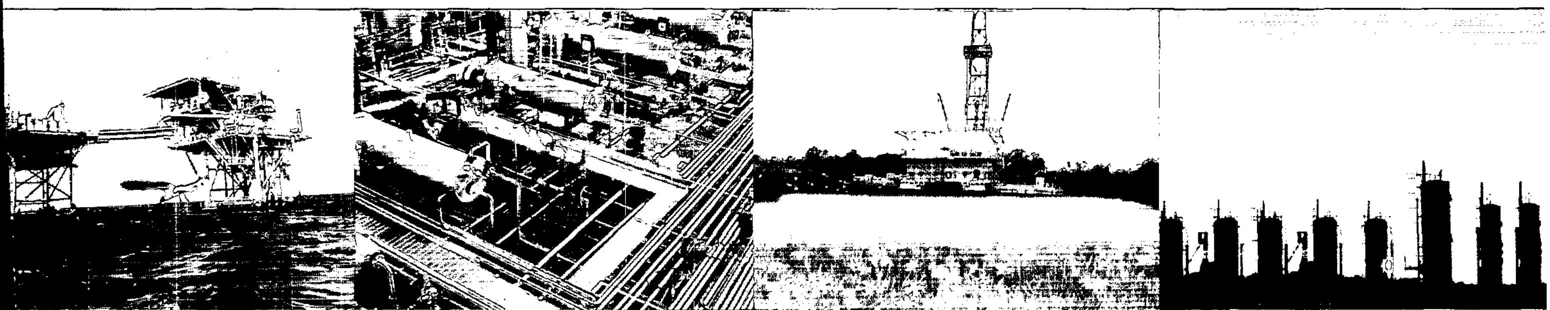
value & commitment

FOR CONTINUED SUCCESS

2002 Annual Report



STONE
ENERGY

Stone Energy Corporation

Stone Energy Corporation is an independent oil and natural gas company active primarily in the Gulf Coast Basin since 1973 having established extensive geological, geophysical, technical and operational expertise in this area. Our business strategy, which has remained consistent since 1990, is to increase reserves, production and cash flow through the acquisition, exploitation and development of mature properties. Our property portfolio consists of 57 active properties and 31 primary term leases in the Gulf Coast Basin, and 32 active properties in the Rocky Mountains.

Operational & Financial Performance

Year Ended December 31,

	2002	2001	2000	1999	1998
Production					
Oil (MBbls)	**6,237**	4,023	4,449	4,324	3,601
Gas (MMcf)	**67,027**	68,236	72,239	65,513	50,897
Oil and Gas (MMcfe)	**104,449**	92,374	98,933	91,457	72,503
Average Sales Prices [1]					
Oil (per Bbl)	**$ 25.00**	$ 25.62	$ 26.66	$ 16.19	$ 13.40
Gas (per Mcf)	**3.31**	4.29	3.64	2.27	2.26
Oil and Gas (per Mcfe)	**3.61**	4.28	3.86	2.39	2.25
Estimated Proved Reserves					
Oil (MBbls)	**52,019**	55,391	33,625	35,213	27,143
Gas (MMcf)	**438,652**	442,669	398,524	385,667	370,772
Oil and Gas (MMcfe)	**750,766**	775,015	600,274	596,945	533,630
Present Value of Estimated Future					
Pre-Tax Net Cash Flows (in thousands)	**$1,784,761**	$1,038,797	$2,941,790	$830,606	$450,583

(amounts in thousands, except per share data)					
Total Oil & Gas Revenue	**$ 377,495**	$ 395,499	$ 381,938	$218,415	$163,217
Net Income (Loss) [2]	**55,399**	(71,375)	126,457	37,066	(66,524)
Per Share [2]	**2.09**	(2.73)	4.80	1.58	(3.23)
Net Cash Flow from Operating Activities	**222,921**	315,617	302,082	123,010	118,014
Oil and Gas Properties, net [2]	**1,047,936**	993,906	747,574	587,661	492,349
Total Assets [2]	**1,179,371**	1,101,783	944,104	706,958	581,134
Long-Term Debt	**431,000**	426,000	148,000	134,000	289,936
Stockholders' Equity [2]	**577,488**	530,025	587,577	452,870	213,131
Weighted Average Shares					
Outstanding—Diluted	**26,494**	26,111	26,335	23,416	20,574

(1) Includes the cash effects of hedging.
(2) Includes $237.7 million and $114.3 million reduction in carrying value of oil and gas properties during 2001 and 1998, respectively.

Dear Fellow Shareholders

During 2002, we witnessed the bankruptcy filings of several high profile public companies, the indictments of senior executives and the investing public's loss of confidence in corporate America. Given this economic backdrop, I would like to take this opportunity to communicate to you, our shareholders, our course for Stone Energy and the proven principles upon which we stand. We are committed to increasing shareholder value through ethical and responsible business practices that are focused on high returns on capital. We consistently practice and are further committed to the belief that we have a responsibility to improve the quality of life in our communities and the environment in which we operate. Historically, Stone has applied these principles to a clear and consistent business strategy of searching for large reserves of oil and gas on and around mature properties already established as major producing fields. This strategy requires a level of technical excellence that few possess and a commitment to in-depth geological field studies that even fewer are willing to undertake. We have established our reputation in a risk-taking industry for being fiscally conservative and responsible in all aspects of our business.

Stone Energy has demonstrated that there is solid value in a company with a consistent technical and business strategy and the competence and resources required to execute the plan across turbulent economic cycles. Since our entry into the public market place in 1993, we have fostered a corporate culture of employee loyalty built on the notion that employee incentives should be in direct correlation with growth in shareholder value. I believe that this culture and our approach to finding oil and gas have been key to our success. The search for oil and gas is not an adventure, rather a technical business that requires a proven and practical approach to judge results. Our goal is to increase shareholder value by locating and producing previously bypassed or unrecognized oil and gas reserves. We are proud to have built solid value for our shareholders gradually and consistently, rather than create hollow value quickly and sporadically. Our financial achievements are the result of the application of our strategy, which I believe is as viable today as it was at our inception.

Growth in our property base is critical to our future. Two major transactions during 2001 more than doubled the Gulf Coast Basin producing properties under our management as well as substantially increased our inventory of exploratory leases. Our property base has allowed us to grow production at a compounded annual rate of 28% and reserves at a compounded annual rate of 26% since going public. Additionally, this property base represents our farmland of development opportunities and our hunting preserve for exploratory discoveries. The true value of acquired properties is not the reserves initially booked with the transactions, but the unbooked value we will add in years to come. All of us at Stone are engaged in understanding why these properties have been successful over time, so that we can define and capture the reserves and value that have gone unrecognized.

During 2002, we successfully grew our production stream 13% to a record volume of over 104 Bcfe. For the first time in our history, we did not replace produced volumes with new reserves. In the past, we have relied on a balanced program of drilling and acquisitions to grow reserve volumes on an absolute and per share basis. Following 2001's property acquisitions, which effectively doubled our proved reserves and property base, we relied on our drilling program in 2002 to replace production while we studied and integrated our newly acquired properties. While our proved reserves were down 3% from 2001, our prospect inventory, after considering the prospects drilled during 2002, increased 12% during the year. Although we are certainly not satisfied with 2002's reserve replacement ratio, we understand that exploratory successes are not uniform. Therefore, we are neither discouraged nor dissuaded from our strategy. Replacing future production, which we expect will continue to grow in the long-term, will require us to target both strategic acquisitions and the exploration potential in our growing prospect inventory. For 2003, we have designed a capital expenditures program to invest in a number of deep, high-impact prospects that, when combined with the remainder of our budgeted 2003 operations, should enable us to initiate a new streak of annual reserve replacement.

The cost of finding new reserves in mature North American basins has increased as we drill prospects that are more subtle and difficult to image and access than earlier discoveries. Offsetting this challenge are improvements in technology including the seismic data we use to identify these prospects, and improvements in the tools we employ to drill and produce them. These improvements have allowed us to test prospects not previously accessible or imagined. A substantial volume of reserves remains to be discovered in mature basins in which we have established a presence. These discoveries will come as the finite supply of and the rising demand for energy resources drive future advancements in technology that promise to lower the risk and cost of drilling. Our industry is capital intensive and to be successful requires financial strength and the ability to move quickly on new opportunities. We benefit from being well capitalized through a consistent discipline of not spending beyond our means and keeping dry powder in the form of market alternatives and approximately $176 million available under our commercial borrowing base.

The Gulf Coast Basin remains our primary focal area with over 90% of our proved reserves and production. During 2002, we began to expand our search for new reserves beyond the coastal and shelf waters of the Gulf of Mexico. Our 2001 acquisitions provided us our first strategic position in the deep-water environment of the Gulf of Mexico. We restructured our technical efforts in the Rocky Mountain property base from a lease and exploration program to an "acquire and exploit" effort that focused on the Green River Basin. With early successes at the Jonah and Pinedale Anticline Fields, this program has doubled our daily production in the Rockies and provided defined drilling locations for the next several years.

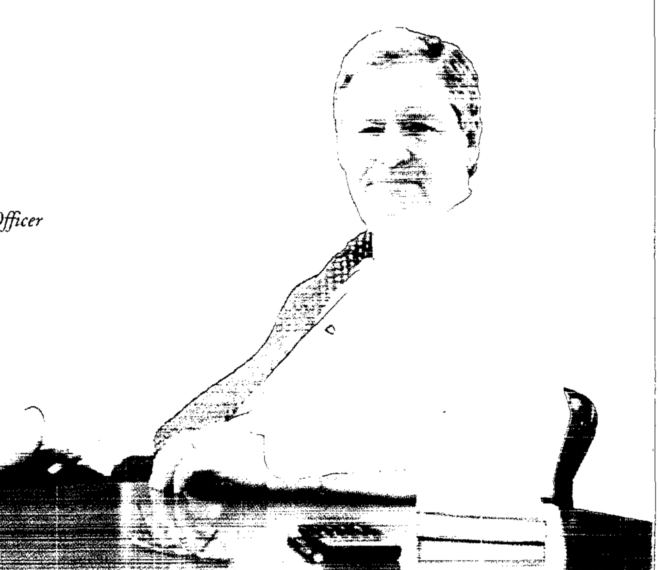
As we continue to grow, we plan to expand our search into new areas of opportunity that fit our strategic profile. We will do this only as we develop the technical expertise to participate at the same high standard for which we are known. As always, our success rests on the creativity of our employees who identify the prospects that are our work product.

As we move into our 10th year as a public company, we are a far stronger enterprise, yet much the same as when we began. We are still grounded in the belief that solid performance with quality and committed employees creates shareholder value. We pursue superior performance in a challenging business through a proven and consistent approach. We applaud and appreciate your confidence in Stone Energy and we pledge to you that we will continue to reward your confidence with uncompromising ethics and strong positive results.

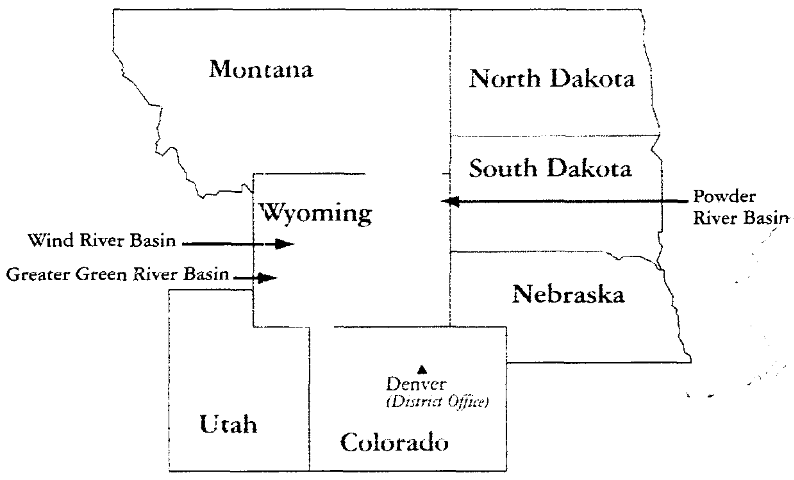
Sincerely,

D. Peter Canty

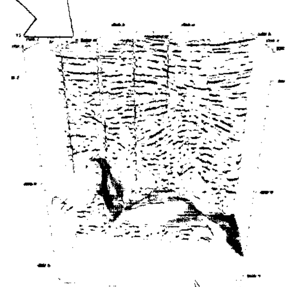
President and Chief Executive Officer



"Stone Energy has demonstrated that there is solid value in a company with a consistent technical and business strategy."



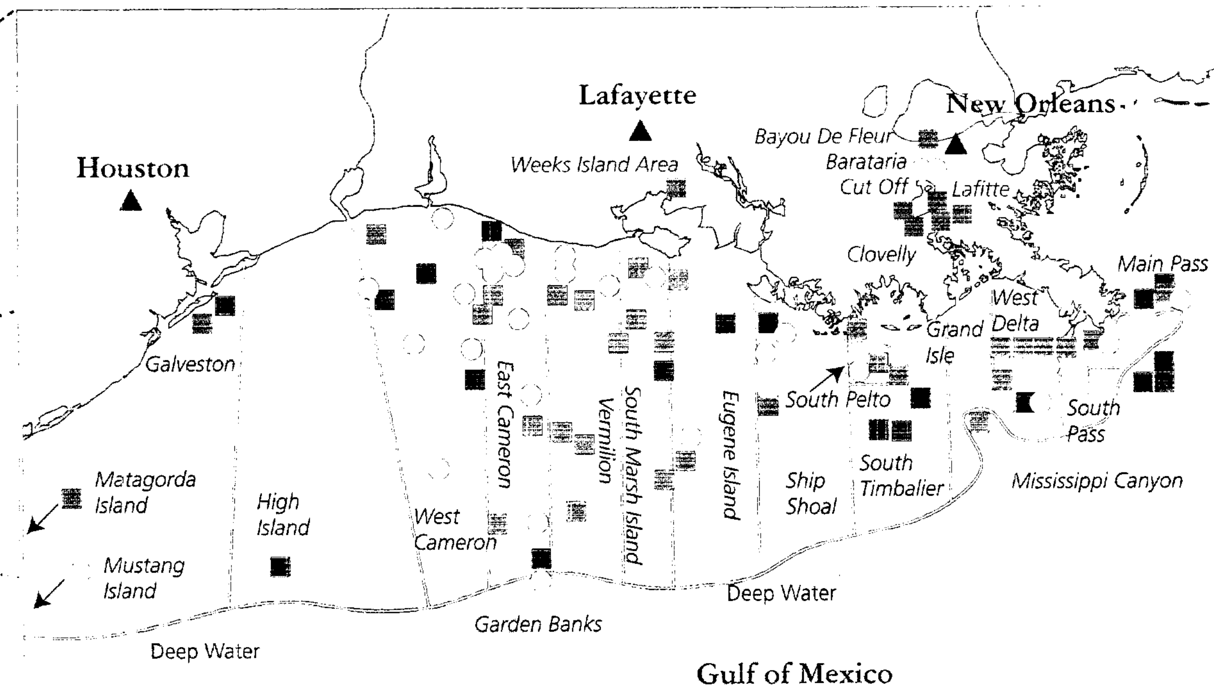
PROSPECT CYCLE:



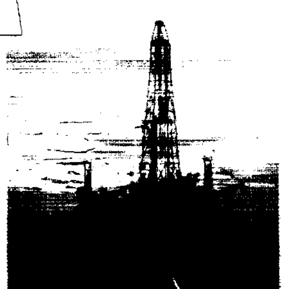
Acquisition Field Analysis
The Prospect Cycle begins with identification of a potential area that meets Stone's strategic profile of established production history, existing infrastructure and low production rate at the time of acquisition.

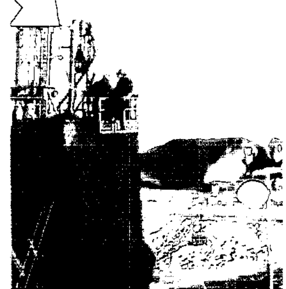
Integrated Mapping
We employ detailed mapping techniques on all fields in an effort to identify bypassed or unmapped potential prospects utilizing well, geophysical and engineering information.

Investment Committee
With a flat management structure, Stone is able to analyze prospects and commence operations in a relatively short period of time.



Active Properties—Operated   Active Properties—Non-Operated   Exploratory Leases





Drill Prospect
Stone contracts experienced and skillful drilling companies to test our objective sands on land or offshore prospects.

Post-Drill Analysis
We analyze the results of drilling to identify future opportunities and to optimize the impact on production and reserves.

Production
The ultimate goal of the Prospect Cycle is to bring our production to market with high margins generating solid returns for our shareholders.

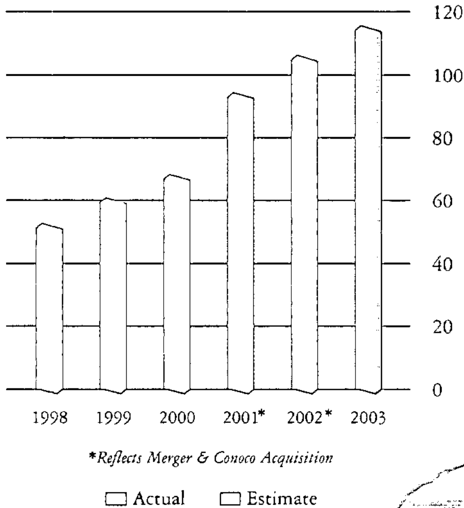
Field Review
Our technical analysis integrates geology, geophysics, engineering and field operations for the purpose of understanding and exploiting the economic potential of the property.

Building Upon Core Values

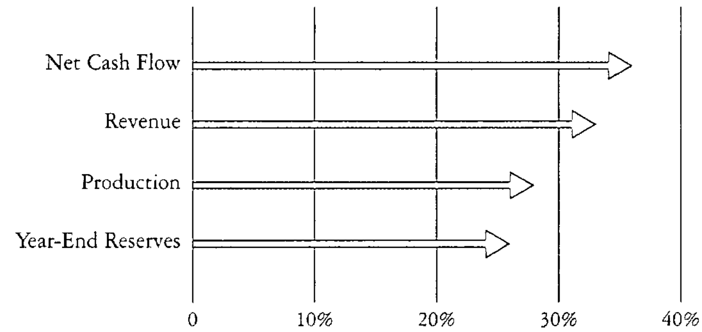
During 2002, we committed significant resources to the evaluation of properties acquired through 2001's merger and acquisition activity. We pride ourselves on the thorough evaluation and mapping of all properties and prospects to the uncompromising Stone standard in search of unidentified or unmapped potential. In mapping our newly acquired properties, we identified additional prospects and began exploiting these reserves with drilling successes in the West Cameron Block 45 and Main Pass Block 288 fields. Experience tells us that there is significant value to be gained from the detailed evaluation and analysis process.

The growth in our Company required a significant commitment to our human resources. Over the last five years, our employee base has more than doubled as we have grown and expanded our geographic reach. Stone employs individuals who are committed to achieving a common goal in a work environment that fosters creativity and innovation. Our employees' belief in the corporate strategy and our foundation of core values are the driving forces behind Stone's continued growth and success. Stone is committed to the needs of our employees, equipping them with the tools necessary to generate the prospects to secure our future.

Production Growth
(Bcfe)



Compound Annual Growth Rate
(1993–2002)



"We are committed to increasing shareholder value through ethical and responsible business practices that are focused on high returns on capital."

104 Bcfe

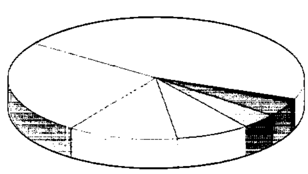
PRODUCTION, 13% GROWTH FROM 2001

Activity in Our Fields

Stone drilled and evaluated 48 wells during 2002 that resulted in 37 completions and 11 dry holes, a 77% success rate. Of our 2002 capital expenditures program, approximately 35% was allocated to projects in our primary focal area where we were not the operator. Our 2003 program will reduce the number of wells drilled by other operators from 24 to approximately 11. During 2003, we plan to focus one-third of our capital expenditures on four field development projects with 13 new wells. These multi-well projects on fields acquired in December 2001 are the result of our detailed and successful exploitation mapping efforts.

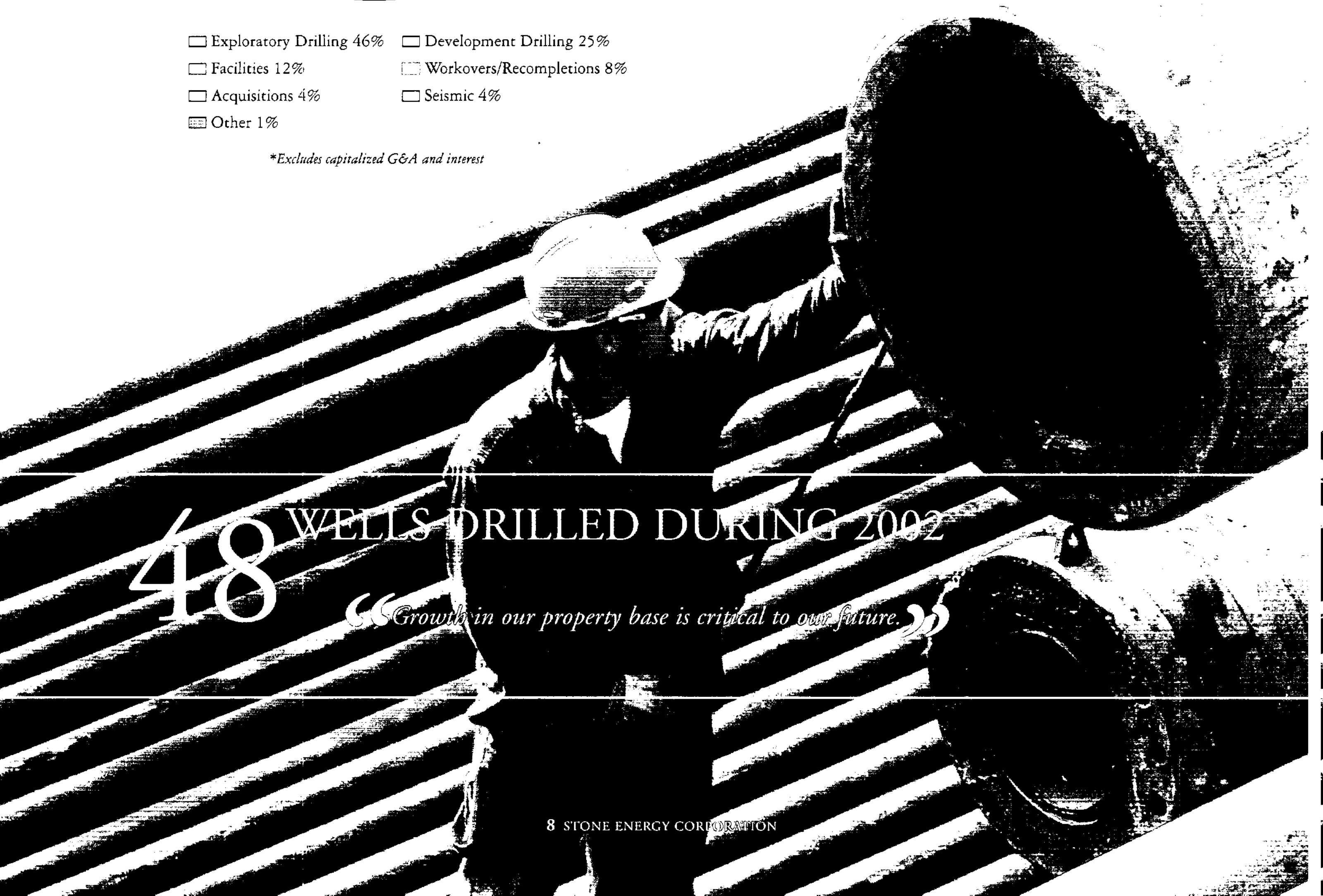
In March of 2003, we made a significant discovery on a deep exploratory prospect on South Pelto Block 22. The well logged over 400 net feet of pay in multiple sands. We are working with our partner to determine the number of future delineation wells and the size of production facilities necessary to develop this discovery. Our goal is to bring production from this discovery on-line during the second half of 2003.

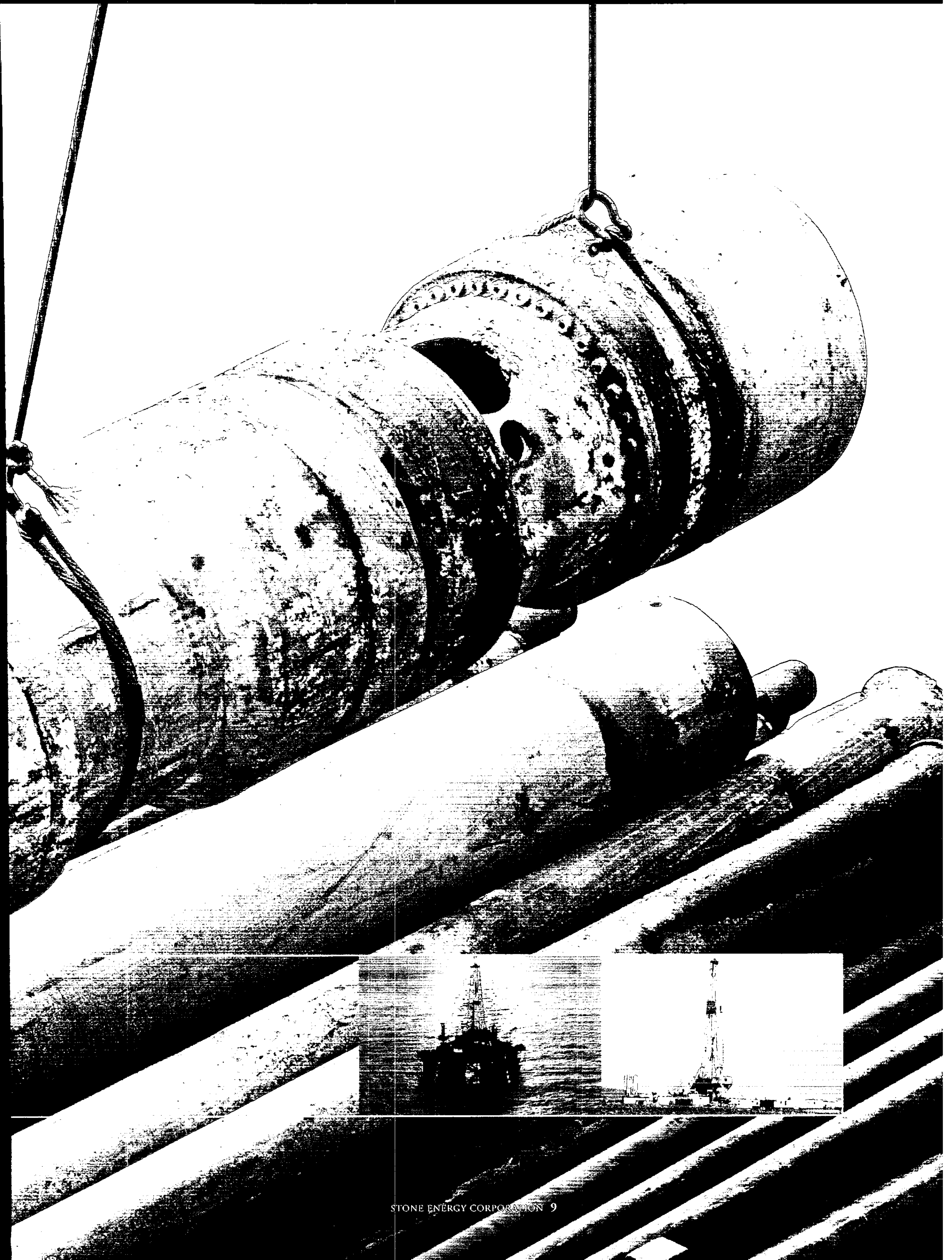
2002 Capital Expenditures*
($196.6 Million)



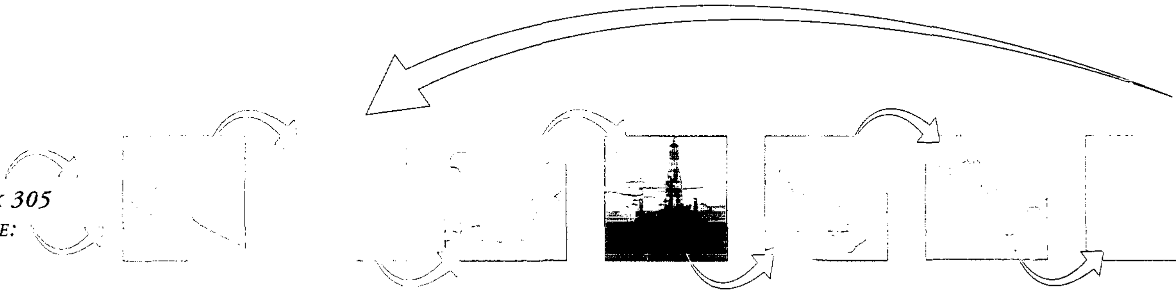
Exploratory Drilling 46% | Development Drilling 25%
Facilities 12% | Workovers/Recompletions 8%
Acquisitions 4% | Seismic 4%
Other 1%

**Excludes capitalized G&A and interest*

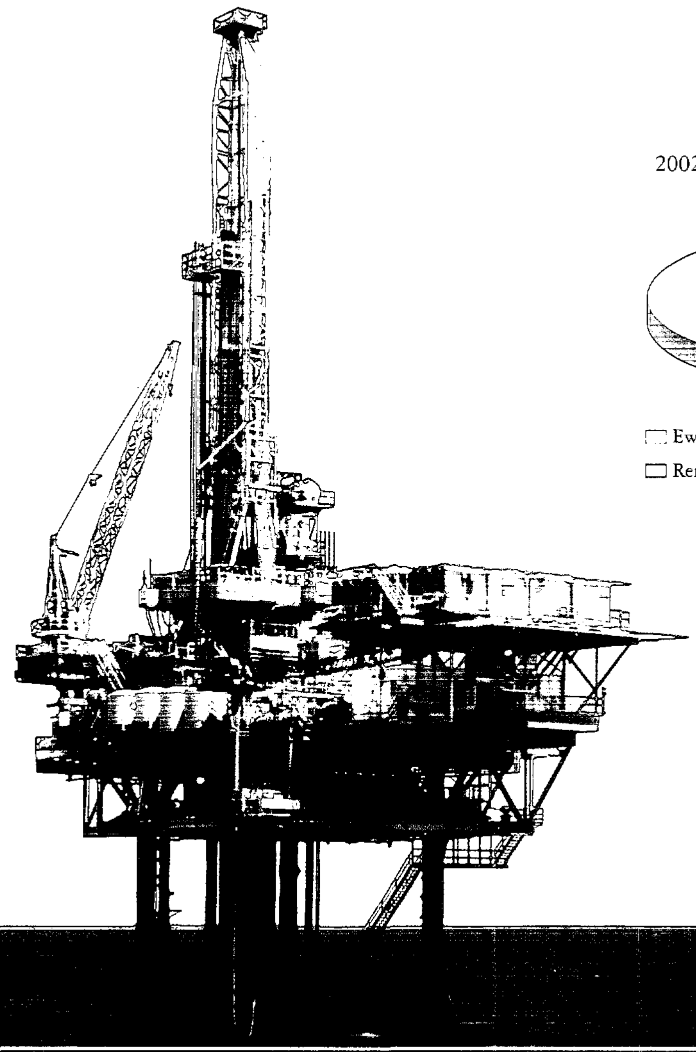




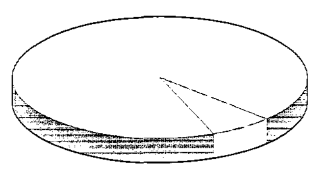
Ewing Bank Block 305
Prospect Cycle:



Acquisition Field Analysis	Integrated Mapping	Investment Committee	Drill Prospects	Post-Drill Analysis	Production	Field Review
December 2001	*July 2002*	*February 2003*	*May 2003*			



2002 Oil & Gas Production



Ewing Bank Block 305 7%
Remaining Production 93%

73%
CASH MARGIN ON REVENUE

"The Gulf Coast Basin remains our primary focal area with over 90% of our proved reserves and production. During 2002, we began to expand our search for new reserves beyond the coastal and shelf waters of the Gulf of Mexico."

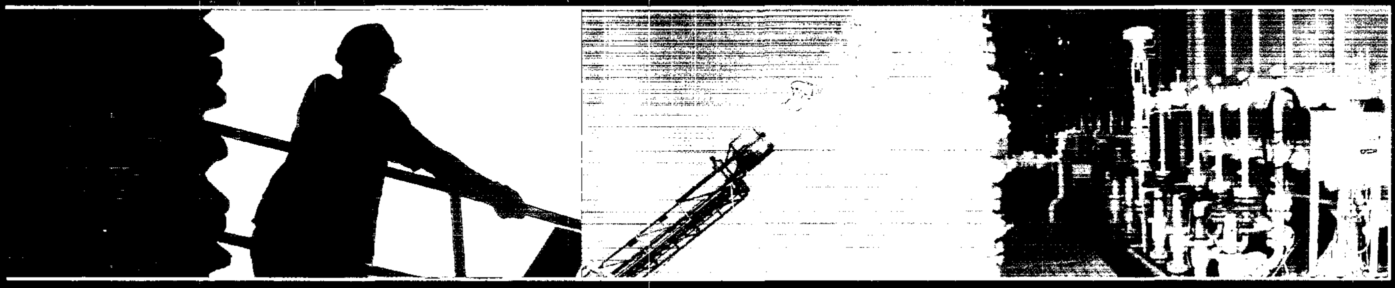
GULF COAST BASIN—EWING BANK BLOCK 305

A critical component of our strategy is the careful consideration of all potential acquisitions and their impact on our shareholders. In December 2001, we acquired Ewing Bank Block 305 with the purchase of a package of eight producing properties. This field met all of our strategic acquisition criteria with significant production history, low current production (relative to peak rates), existing infrastructure, multiple productive horizons, identified opportunities and operatorship. In February 2003, we exercised our right to acquire an additional interest in the Ewing Bank Block 305 field, increasing our working interest to 100%.

The drilling phase is the next step in our "Prospect Cycle" (introduced on pages 4 & 5) for this field after analysis and mapping processes during the last 12 months. After detailed planning and evaluation, we organized a drilling program to prove there are significantly more reserves in this field than previously recognized that, when developed and produced, will grow value for our shareholders. (See opposite page) This field, which is yet to be rejuvenated, accounted for seven percent of our total production during 2002, generating close to $30 million in revenue. In keeping with our belief that more hydrocarbons can be found in and around mature fields, we planned a multi-well drilling, workover and recompletion program in the Ewing Bank Block 305 field for 2003. This activity will account for approximately eight percent of our total budgeted capital expenditures of $240 million, excluding acquisitions.

ROCKY MOUNTAINS—PINEDALE ANTICLINE

In 2001, we refocused our Rocky Mountain strategy of exploration to an acquisition and exploitation effort that parallels our Gulf Coast Basin operation. In connection with this refocusing effort, we increased our exposure to long-life reserves in the Rocky Mountains through a $28 million work commitment in the prolific Pinedale Anticline in the Greater Green River Basin of Wyoming. This commitment allows us to earn a 50% working interest in 11,000 acres of a structure currently being aggressively explored by a number of larger energy companies. This acquisition extended our reserve life in the Rocky Mountain region and created a hedge against the steep production declines of the Gulf Coast Basin. It also generated additional cash flow to support future capital expenditures. Since acquiring interests in the region, we have doubled production in our Rocky Mountain program. In an effort to lock in attractive rates of return on this project, we have entered into fixed price swap contracts for 10,000 MMBtus per day at a swap price of $3.68 per MMBtu during 2003, and 15,000 MMBtus per day at a swap price of $3.42 for 2004 and 2005. During 2002, we invested eight percent of our total capital expenditures in the Rocky Mountains and will continue to diversify Stone's property base in order to achieve our strategic objectives. Along these lines, we have allocated 14% of our 2003 capital expenditures budget to the Rocky Mountains.




STONE
ENERGY

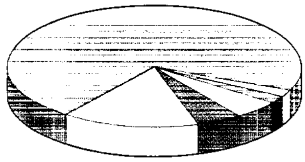
Our Continued Strategy

Geopolitical factors around the globe created a significant premium on the price of oil during the year which helped generate realization of $25.00 per barrel of oil produced for Stone and resulted in over $155.9 million in oil revenue. Natural gas prices experienced traditional seasonal fluctuation with the withdrawal from, and injections into, national inventory levels. During the year, we realized $3.31 per Mcf of natural gas, which generated approximately $221.6 million in natural gas revenue for our Company.

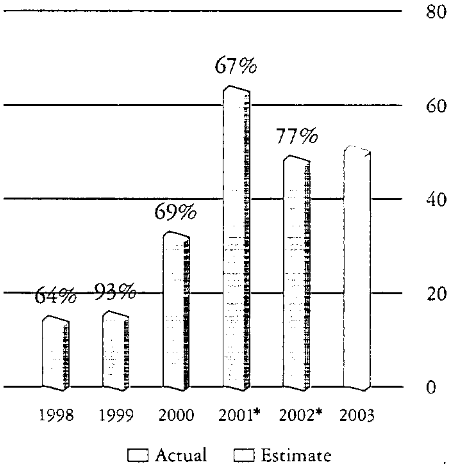
As a means of managing commodity price fluctuations, we have entered into put contracts for a portion of our natural gas production for 2003. These contracts provide a floor price for our natural gas production while we enjoy all realized prices above the contract floor. These contracts guarantee certain levels of cash flow from production that will underwrite a portion of our capital expenditures budget for 2003. In the event cash flow is insufficient to fund our budget, we maintain a credit facility that has more than sufficient capacity to fund any remaining expenditures.

Our 2003 capital expenditures budget is designed to continue the growth of Stone. We will invest over $240 million in new wells from cash flow, including approximately 14% in the Rocky Mountain region where we see growth opportunities. Going forward, we plan to continue a balanced program of acquisitions and drilling that encompasses a strategic mix of exploratory and development activities to increase both production and reserves. Our expected cash flow during 2003, backed by our conservative hedging program, should provide ample support to our near-term spending budget and enable us to further reduce our debt to position Stone for future acquisition opportunities. Through the first three months of 2003, we repaid $20 million of borrowings under our bank credit facility.

HIGH OPERATING MARGINS
5-Year Average
(Total Revenue $3.30/Mcfe)



STONE ENERGY DRILLING ACTIVITY
(Number of Gross Wells Drilled)



(Percentage represents drilling success rate)

**Reflects Merger & Conoco Acquisition*

$377 MILLION IN OIL AND GAS REVENUE

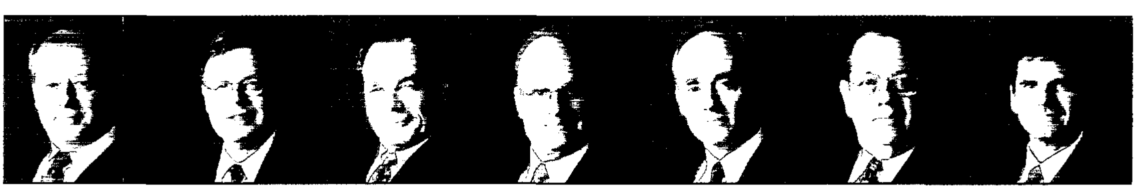
"We pursue superior performance in a challenging business through a proven and consistent approach."

Board of Directors

Top row from left to right: James H. Stone, B.J. Duplantis, David R. Voelker, John P. Laborde, Peter K. Barker
Bottom row from left to right: Richard A. Pattarozzi, D. Peter Canty, Raymond B. Gary, Joe R. Klutts, Robert A. Bernhard
Not pictured: George R. Christmas

Audit Committee
Peter K. Barker—*Chairman*
Robert A. Bernhard
Raymond B. Gary

Compensation Committee
Richard A. Pattarozzi—*Chairman*
Raymond B. Gary
David R. Voelker



Senior Management

From left to right: Andrew L. Gates, III, Craig L. Glassinger, E.J. Louviere, Michael E. Madden, J. Kent Pierret, James H. Prince, Gerald G. Yunker

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

FORM 10-K

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

For the fiscal year ended December 31, 2002

or

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

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 Exchange Act Rule 12b-2).

[x] Yes   [ ] No

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $936,572,662 as of June 28, 2002 (based on the last reported sale price of such stock on the New York Stock Exchange Composite Tape on that day).

As of March 10, 2003, the registrant had outstanding 26,315,195 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 21, 2003 are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

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 a Gulf Coast Basin-focused independent oil and gas company engaged in the acquisition and subsequent exploration, exploitation, development, production and operation of oil and gas properties. Our corporate headquarters are located at 625 E. Kaliste Saloom Road, Lafayette, Louisiana 70508. We make available free of charge on our Internet website (www.stoneenergy.com) our annual reports 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 is electronically filed with, or furnished to, the Securities and Exchange Commission (the "SEC"). We also intend to disclose our Code of Business Conduct and Ethics, which our board of directors approved in 2002, on our Internet website. We will make immediate disclosure either by Form 8-K or on our website of any change to, or waiver from, this code for our principle executive and senior financial officers.

Strategy and Operational Overview

The Gulf of Mexico is a critical supply basin for the United States, accounting for approximately 25% of the total U.S. oil and natural gas production in 2002. Properties located in the Gulf of Mexico are typically on 5,000-acre lease blocks and afford a substantial area to explore away from and beneath established production. We have been active in the Gulf Coast Basin since 1973 and have established extensive geological, geophysical, technical and operational expertise in this area. The application of these core strengths, combined with our detailed and thorough approach to evaluating mature fields and our utilization of new drilling, seismic and completion technologies, has enabled us to successfully exploit and derive significant value from mature Gulf Coast Basin properties. As of March 10, 2003, our property portfolio consisted of 57 active properties and 31 primary term leases in the Gulf Coast Basin and 32 active properties in the Rocky Mountains.

Our business strategy, which has remained consistent since 1990, is to increase reserves, production and cash flow through the acquisition, exploitation and development of mature properties located primarily in the Gulf Coast Basin. Since going public in 1993, we have grown reserves, production and cash flow from operating activities at compounded annual rates of 26%, 28% and 36%, respectively. Approximately 93% of our estimated proved reserves at December 31, 2002 and 95% of our production during 2002 were associated with our Gulf Coast Basin properties. As of December 31, 2002, we had estimated proved reserves of approximately 750.8 billion cubic feet of gas equivalent (Bcfe), 76% of which were classified as proved developed and 58% of which were natural gas. For the year ended December 31, 2002, we produced an average of 286.2 million cubic feet of gas equivalent per day (MMcfe/d). This production rate generated over 104 Bcfe of total production volumes, 64% of which was natural gas. During 2002, we generated net cash flow from operating activities of $222.9 million.

We apply the latest production techniques and geophysical interpretation tools to established fields with significant historical production that have been under-evaluated in recent years. We have grown our opportunity base through both the drillbit and strategic acquisitions, implementing a conservative financial strategy that incorporates a combination of internal cash flow, equity issuance and indebtedness to fund our acquisition and exploitation activities. While we have acquired substantially all of our properties from third parties, we have generated significant growth in reserves, production and prospect inventory subsequent to acquisition. We believe significant reserves remain to be discovered and exploited on properties that satisfy our acquisition criteria as the focus of oil and gas companies shifts over time. We also believe that we are well positioned to exploit these reserves by applying our technical expertise and our thorough, consistent and patient approach in the evaluation and acquisition of these properties.

We seek to acquire properties that have the following characteristics:

- primarily Gulf Coast Basin location;
- 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.

Our approach to evaluating mature fields in the Gulf Coast Basin involves a combination of techniques designed to generate opportunities and unlock value. By using the extensive production history and data accumulated on properties in the Gulf Coast Basin, our highly experienced technical teams construct an interpretation of a field's unique geology 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, we have achieved a 74% drilling success rate.

Prior to acquiring a property, we perform a thorough geological, geophysical and engineering analysis of the property to formulate a comprehensive development plan. To formulate this plan, we utilize the expertise of our technical team of 21 geologists, 17 geophysicists and 26 engineers. We also employ our extensive technical database, which includes both 3-D and 4-C 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.

Financial Overview

We were incorporated in Delaware in 1993. We completed our initial public offering of common stock in July 1993 and our shares are listed on the New York Stock Exchange under the ticker symbol "SGY." Additional offerings of common stock were completed in November 1996 and July 1999. We have maintained consistent, profitable growth since our initial public offering in 1993. We have generated net income in all calendar quarters except the fourth quarter of 1998 and third quarter of 2001, both of which included non-cash ceiling test write-downs of our oil and gas properties due to depressed oil and gas prices.

In September 1997, we completed an offering of $100 million principal amount of 8¾% Senior Subordinated Notes due 2007. In December 2001, we issued $200 million principal amount of 8¼% Senior Subordinated Notes due 2011 to finance a portion of our acquisition of eight producing properties from Conoco, Inc.

We have a borrowing base under our bank credit facility of $300 million, with availability of an additional $160.9 million of borrowings as of March 10, 2003. The borrowing base limitation is re-determined periodically and is based on a borrowing base amount established by the bank group after its evaluation of the value of our proved oil and gas reserves.

Oil and Gas Marketing

Our oil, natural gas and natural gas condensate production is sold at current market prices under short-term contracts providing for variable or market sensitive prices. We derived 10%, 24% and 11% of our total oil and natural gas revenue from Conoco, Inc., Duke Energy Trading and Marketing LLC, and Reliant Services, Inc., respectively, for the year ended December 31, 2002. No other purchaser accounted for 10% or more of our total oil and natural gas revenue during 2002. 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, natural gas and natural gas condensate. 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 proved 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, 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. See "Regulation - Federal Regulation of Sales and Transportation of Natural Gas." 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 gas and thus the prices available for sales of oil and gas.

Regulation

Our oil and gas operations are subject to numerous U.S. federal, state and local laws and regulations. See "Risk Factors - Our oil and gas operations are subject to various U.S. federal, state and local government regulations that materially affect our operations."

Regulation of Production. In all areas where we operate, there are statutory provisions regulating the production of oil and natural gas under which administrative agencies may enforce rules in connection with the location, spacing, drilling, operation and production of both oil and gas wells, determine the reasonable market demand for oil and gas and establish allowable rates of production. These regulatory orders can limit the number of wells or the location where wells may be drilled. Regulation can also restrict the rate of production below the rate that these wells would otherwise produce in the absence of such regulatory orders. Any of these actions could negatively impact the amount or timing of revenues.

Federal Leases. We have oil and gas leases both onshore and in the Gulf of Mexico, which were granted by the federal government. Operations on onshore federal leases must be conducted in accordance with permits issued by the federal Bureau of Land Management and are subject to a number of other regulatory restrictions, such as restrictions on activities that might interfere with wildlife breeding and nesting and drilling limitations imposed by resource management plans. Moreover, on certain federal leases, prior approval of drillsite locations must be obtained from the U.S. Environmental Protection Agency (the "EPA"). On large-scale projects, lessees may be required to perform Environmental Impact Statements to assess the environmental effects of potential development, which can delay project implementation or result in the imposition of environmental restrictions that could have a material impact on the cost or scope of such project.

Offshore leases are administered by the United States Department of the Interior Minerals Management Service (the "MMS"). Offshore lessees must obtain MMS approval of exploration, development and production plans prior to the commencement of these operations. In addition to permits required from other agencies (such as the U.S. Coast Guard, the Army Corps of Engineers and the EPA), lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has enacted regulations requiring offshore production facilities located on the Outer Continental Shelf ("OCS") to meet stringent engineering, construction and safety specifications. The MMS also has regulations restricting the flaring or venting of natural gas, and prohibiting the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS has enacted other regulations governing the plugging and abandoning of wells located offshore and the removal of all production facilities. Lessees must also comply with detailed MMS regulations governing the calculation of royalty payments and the valuation of production and permitted cost deductions for that purpose. In 2000, the MMS issued a final rule modifying the valuation procedures for the calculation of royalties owed for crude oil sales. When oil production sales are not in arms-length transactions, the new royalty calculation will base the valuation of oil production on spot market prices instead of the posted prices that were previously utilized. We are currently selling our crude oil under arms-length transactions in a manner that we believe to be acceptable to the MMS under its 2000 rule. This rule has not had a material adverse effect on our results of operations.

With respect to any operations conducted on offshore federal leases, liability may generally be imposed under the Outer Continental Shelf Lands Act (the "OCSLA") for costs of clean-up and damages caused by pollution resulting from these operations, other than damages caused by acts of war or the negligence of third parties. To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees post substantial bonds or other acceptable financial assurances that these obligations will be met. The cost of bonds or other surety can be substantial and there is no assurance that bonds or other surety can be obtained in all cases.

Operators in the OCS waters of the Gulf of Mexico are also required to post area-wide bonds and individual lease bonds of $3 million and $1 million, respectively, unless the MMS allows exemptions or reduced amounts. We currently have an area-wide right-of-way bond for $0.3 million and an area-wide lessee's and operator's bond totaling $3 million issued in favor of the MMS for our existing offshore properties. The MMS also has discretionary authority to require supplemental bonding in addition to the foregoing required bonding amounts but this authority is only exercised on a case-by-case basis at the time of filing an assignment of record title interest for MMS approval. Based upon certain financial parameters, we have been granted exempt status by the MMS, which exempts us from the supplemental bonding requirements. There is no assurance, however, that such exemption will be maintained. Under certain circumstances, the MMS may require any of 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.

Oil Price Controls and Transportation Rates. Sales of crude oil, condensate and gas liquids are not currently regulated and are made at negotiated prices. Effective January 1, 1995, the Federal Energy Regulatory Commission (the "FERC") implemented regulations establishing an indexing system for transportation rates for oil that allowed for an increase in the cost of transporting oil to the purchaser. The implementation of these regulations has not had a material adverse effect on our results of operations. Recently, the FERC reviewed its indexing methodology and concluded no change was needed. On judicial review, however, the court concluded the order was not adequately supported and remanded the decision to the FERC. It is uncertain what action the FERC may take as the result of the remand. It is possible a formula permitting higher rates might be established.

Federal Regulation of Sales and Transportation of Natural Gas. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (the "NGA"), the Natural Gas Policy Act of 1978 (the "NGPA") and regulations promulgated thereunder by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act (the "Decontrol Act"). The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Commencing in 1992, the FERC issued Order No. 636 and subsequent orders (collectively, "Order No. 636"), which require interstate pipelines to provide transportation separate, or "unbundled," from the pipelines' sales of gas. Also, Order No. 636 requires pipelines to provide open-access transportation on a basis that is equal for all shippers. Although Order No. 636 does not directly regulate our activities, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. The implementation of these orders has not had a material adverse effect on our results of operations. The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations.

In 2000, the FERC issued Order No. 637 and subsequent orders (collectively, "Order No. 637"), which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 were upheld on judicial review, though certain issues, such as capacity segmentation and rights of first refusal, were remanded to the FERC, have been considered on remand, and are currently pending rehearing at the FERC. We cannot predict whether and to what extent FERC's market reforms will survive rehearing and further judicial review and, if they do, whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. However, we do not believe that we will be affected by any action taken materially differently than other natural gas producers and marketers with which we compete.

The OCSLA requires that all pipelines operating on or across the OCS provide open-access, non-discriminatory service. Commencing in April 2000, the FERC issued Order Nos. 639 and 639-A (collectively, "Order No. 639"), which imposed certain reporting requirements applicable to "gas service providers" operating on the OCS concerning their prices and other terms and conditions of service. The purpose of Order No. 639 is to provide regulators and other interested parties with sufficient information to detect and to remedy discriminatory conduct by such service providers. The FERC has stated that these reporting rules apply to OCS gatherers and has clarified that they may also apply to other OCS service providers including platform operators performing dehydration, compression, processing and related services for third parties. The U.S. District Court overturned the FERC's reporting rules as exceeding its authority under OSCLA. The FERC has recently appealed this decision. We cannot predict whether and to what extent these regulations might be reinstated, and what effect, if any, they may have on us. The rules, if reinstated, may increase the frequency of claims of discriminatory service, may decrease competition among OCS service providers and may lessen the willingness of OCS gathering companies to provide service on a discounted basis.

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

Environmental Regulations. Our operations are subject to numerous stringent and complex laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties, the issuance of remedial requirements, and the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and gas industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, there is no assurance that this trend will continue in the future.

The Oil Pollution Act, as amended ("OPA"), and regulations implemented thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters, including the OCS. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75 million in other damages. Few defenses exist to the liability imposed by OPA.

OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. 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 million in specified state waters to at least $35 million in OCS waters, with higher amounts of up to $150 million 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.

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

The EPA has in the past indicated that we may be potentially responsible for costs and liabilities associated with alleged releases of hazardous substances at the Gulf Coast Vacuum Services Superfund site near Abbeville, Louisiana. However, as noted on the EPA Region 6 website, the Gulf Coast Vacuum Services site was delisted from the final Superfund list on July 23, 2001, and we have not received any recent correspondence from the EPA regarding this site. In an unrelated matter, during 2002, we commenced negotiations with a private party who is seeking a contribution of approximately $200,000 with respect to remediation of the Mar Services site in St. Landry Parish, Louisiana. These negotiations are currently ongoing. We do not expect our possible involvement in either of the Gulf Coast Vacuum Services site or the Mar Services site to have a material adverse effect on our operations.

The Resource Conservation and Recovery Act, as amended ("RCRA"), generally does not regulate most wastes generated by the exploration and production of oil and natural gas. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, legislation has been proposed in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the oil and gas industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

We currently own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of oil and gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or under other locations where such wastes have been taken for disposal. In addition, most of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

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

Employees

At March 10, 2003, we had 210 full time employees. We believe that our relationships with our employees are satisfactory. None of our employees are covered by a collective bargaining agreement. From time to time we utilize the services of independent contractors to perform various field and other services.

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 natural gas and liquids 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 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, 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 and state 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.

The publicly disclosed deteriorating financial conditions and recently reduced credit ratings of certain purchasers of production increase the possibility that 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 letters of credit, guarantees and prepayments 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 revenues 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. Therefore, 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, 2002, approximately 24% of our estimated proved reserves were proved undeveloped and 40% were proved developed non-producing. 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 behind pipe 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 estimated present value of 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 estimated discounted future net cash flows from proved reserves are 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 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%, 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 recorded an after-tax write-down of $154.5 million ($237.7 million pre-tax) at the end of the third quarter of 2001 due to low natural gas prices on the last day of that quarter. There was no loss of proved reserve volumes associated with the ceiling test write-down. 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 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, were $215.6 million during 2002, $641.3 million during 2001 and $269.1 million during 2000. We have budgeted total capital expenditures in 2003, excluding property acquisitions, capitalized salaries, general and administrative costs and interest, of approximately $240 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 spend 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 expenditures. We cannot assure you that additional debt or equity financing or cash flow provided by operations will be available 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. During 2002, 95% of our production and 93% 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. Gulf of Mexico reservoirs tend to be recovered quickly through production with associated steep declines, while declines in other regions after initial flush production tends 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 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, many 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 carefully designed 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 revenues after operating and other costs to recoup drilling costs.

Our industry experiences numerous operating risks.

The exploration, development and operation 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 currently maintain loss of production insurance to protect against uncontrollable disruptions in production operations. The policy covers the majority of our anticipated production volumes from selected offshore properties on an individual facility basis. The value of lost production would be calculated using the average of the last 45 days' revenue from the facility prior to the loss. We currently maintain coverage of up to $100 million per occurrence that becomes effective after a maximum of 45 consecutive days of lost production.

We also maintain additional 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 redrill and pollution coverage. The exact amount of coverage for each well is dependent upon its depth and location.

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. The terrorist attacks on September 11, 2001 and the changes in the insurance markets attributable to those attacks may make some types of insurance more difficult to obtain. We may be unable to secure the level and types of insurance we would otherwise have secured prior to September 11th. 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 materially and adversely affect our financial condition and operations.

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

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scale. Since the September 11th attacks, 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 business.

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

Our four largest fields, South Pelto Block 23, Mississippi Canyon Block 109, Ewing Bank Block 305 and Eugene Island Block 243, accounted for approximately 38% of our total oil and gas production volumes during 2002. Accordingly, if the level of production from these fields substantially declines, it could have a material adverse effect on our overall production levels and our revenues.

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 December 31, 2002, we had $431.0 million in outstanding indebtedness. We have a borrowing base under our bank credit facility of $300 million with availability of an additional $160.9 million of borrowings as of March 10, 2003.

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 proved 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. 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 federal Oil Pollution Act, as amended (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, the Comprehensive Environmental Response, Compensation, and Liability Act, as amended (the "CERCLA"), and the Resource Conservation and Recovery Act, as amended (the "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 such 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 production quantities may be hedged. These arrangements may include futures contracts on the New York Mercantile Exchange. 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 and Joe R. Klutts, both directors of Stone, collectively own 9% of the working interest in certain wells drilled on Section 19 on the east flank of the Weeks Island Field. These interests were acquired at the same time that our predecessor company acquired its interests in the Weeks Island Field. In their capacity as working interest owners, they are required to pay their proportional share of all costs and are entitled to receive their proportional share of revenue.

D. Peter Canty, Stone's Chief Executive Officer, and James H. Prince, Stone's Chief Financial Officer, were granted net profits interests in some of Stone's oil and gas properties acquired prior to our initial public offering in 1993. In addition, Michael E. Madden, Stone's Vice President of Engineering, 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 indentures executed in connection with our 8¾% Senior Subordinated Notes due 2007 and 8¼% Senior Subordinated Notes due 2011. 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. As of March 10, 2003, our property portfolio consisted of 57 active properties and 31 primary term leases in the Gulf Coast Basin and 32 active properties in the Rocky Mountains.

As of January 1, 2003, we served as operator on 60% of our active properties, including a 68% operating percentage on our Gulf Coast Basin properties. The properties that we operate accounted for 86% of our year-end 2002 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, 2002 by Atwater Consultants, Ltd., Ryder Scott Company, L.P., and Cawley, Gillespie & Associates, Inc., all independent petroleum engineers. All product pricing and cost estimates used in the Reserve Reports are in accordance with the rules and regulations of the SEC, and, except as otherwise indicated, the reported amounts give no effect to federal or state income taxes otherwise attributable to estimated future cash flow from the sale of oil and natural gas. The present value of estimated 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 2002 year-end product prices for all of our properties were $30.41 per barrel of oil and $4.86 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 before income taxes related to such reserves as of December 31, 2002.

	Proved Developed	Proved Undeveloped	Total Proved	Percent Proved Developed
Oil (MBbls)	39,772	12,247	52,019	76%
Natural gas (MMcf)	334,692	103,960	438,652	76%
Total oil and natural gas (MMcfe)	573,324	177,442	750,766	76%
Estimated future net cash flows before income taxes (in thousands)	$2,130,025	$587,236	$2,717,261	78%
Present value of estimated future net cash flows before income taxes (in thousands)	$1,447,996	$336,765	$1,784,761	81%

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 and costs 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,		
	2002	2001	2000
		(In thousands)	
Acquisition costs, net of sales of unevaluated properties	$14,071	$328,778	$15,086
Development costs	96,426	119,426	98,004
Exploratory costs	86,063	176,679	138,420
Subtotal	196,560	624,883	251,510
Capitalized general and administrative costs and interest, net of fees and reimbursements	19,039	16,394	17,634
Total additions to oil and gas properties	$215,599	$641,277	$269,144

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, 2002.

	Gross	Net
Productive Wells:		
Oil (1):		
Gulf Coast Basin	171.00	100.12
Rocky Mountain Basin	138.00	110.00
	309.00	210.12
Gas (2):		
Gulf Coast Basin	135.00	95.00
Rocky Mountain Basin	45.00	20.46
	180.00	115.46
Total	489.00	325.58
Developed Acres:		
Gulf Coast Basin	33,089.00	20,912.40
Rocky Mountain Basin	41,103.00	20,016.85
Total	74,192.00	40,929.25
Undeveloped Acres (3):		
Gulf Coast Basin	462,264.00	329,816.59
Rocky Mountain Basin	206,625.00	123,528.58
Total	668,889.00	453,345.17

(1) 54 gross wells each have dual completions.
(2) 22 gross wells each have dual completions.
(3) Leases covering approximately 16% of our undeveloped gross acreage will expire in 2003, 6% in 2004, 11% in 2005, 3% in 2006, 1% in 2007 and 1% in 2010. Leases covering the remainder of our undeveloped gross acreage (62%) are held by production.

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

	Year Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive	15.00	10.59	22.00	13.84	31.00	17.82
Nonproductive	7.00	5.35	20.00	15.81	20.00	10.65
Development Wells:						
Productive	22.00	10.64	20.00	12.03	24.00	16.68
Nonproductive	4.00	2.66	1.00	0.51	1.00	0.82

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

Goodrich Petroleum Corporation, Goodrich Petroleum Company, L.L.C. and Goodrich Petroleum Company-Lafitte, L.L.C. filed civil action number 2000-06437, in Harris County, Texas, against Stone Energy Corporation, seeking seismic data at Lafitte Field and unspecified damages. Subsequently, the same third party that had granted a data use license to Stone granted a similar license to plaintiffs at no cost and provided plaintiffs with the seismic data. We do not expect this matter to have a material adverse effect on our financial condition.

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 2002.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth information regarding the names, ages (as of March 10, 2003) and positions held by each of our executive officers. Our executive officers serve at the discretion of the board of directors.

Name	Age	Position
D. Peter Canty	56	President, Chief Executive Officer and Director
Andrew L. Gates, III	55	Vice President, Secretary and General Counsel
Craig L. Glassinger	55	Senior Vice President – Planning, Acquisitions and Analysis
E. J. Louviere	54	Vice President – Land
Michael E. Madden	57	Vice President – Engineering
J. Kent Pierret	47	Vice President – Controller and Chief Accounting Officer
James H. Prince	60	Senior Vice President, Chief Financial Officer and Treasurer
Gerald G. Yunker	46	Vice President – Resources

The following biographies describe the business experience of our executive officers for at least the past five years. Stone Energy Corporation was formed in March 1993 to become a holding company for The Stone Petroleum Corporation ("TSPC") and its subsidiaries. In 1997, TSPC was dissolved after the majority of its assets were transferred to Stone Energy Corporation.

D. Peter Canty was named Chief Executive Officer on January 1, 2001 and President in March 1994. He has also served as Chief Operating Officer and as a Director since March 1993. Mr. Canty was President of TSPC from 1994 to 1997.

Andrew L. Gates, III has served as Vice President, Secretary and General Counsel since August 1995.

Craig L. Glassinger was named Senior Vice President – Planning, Acquisitions and Analysis in April 2002. From December 1995 to February 2001 he served as Vice President – Acquisitions and from February 2001 until April 2002 as Vice President – Resources.

E. J. Louviere has served as Vice President – Land since June 1995.

Michael E. Madden was named Vice President – Engineering in March 2002. Previously, he served as the Lafayette District Manager from February 2001 to March 2002. Stone Energy and its predecessors have employed him for 28 years as a consultant and an employee.

J. Kent Pierret was named Vice President – Controller and Chief Accounting Officer in June 1999. Prior to rejoining us, 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.

James H. Prince was named Chief Financial Officer in August 1999 and Treasurer in June 1999. He previously served as Chief Accounting Officer and Controller from 1993 to June 1999. In April 2002, he became a Senior Vice President.

Gerald G. Yunker was named Vice President – Resources in 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.

PART II

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

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
2001		
First Quarter	$65.50	$47.17
Second Quarter	58.00	40.30
Third Quarter	47.50	29.66
Fourth Quarter	40.55	30.78
2002		
First Quarter	$39.24	$32.15
Second Quarter	43.90	36.40
Third Quarter	40.44	29.15
Fourth Quarter	34.92	28.65
2003		
First Quarter (through March 10, 2003)	$36.20	$32.35

On March 10, 2003, the last reported sales price on the New York Stock Exchange Composite Tape was $33.77 per share. As of that date, there were approximately 212 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 indentures executed in connection with our 8¾% Senior Subordinated Notes due 2007 and our 8¼% Senior Subordinated Notes due 2011. 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.

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, 2002. 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,				
	2002	2001	2000	1999	1998
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenue:					
Oil production	$155,913	$103,053	$118,628	$70,025	$48,262
Gas production	221,582	292,446	263,310	148,390	114,955
Total operating revenue	377,495	395,499	381,938	218,415	163,217
Operating expenses:					
Normal lease operating expenses	60,952	47,564	41,474	33,372	26,318
Major maintenance expenses	15,721	6,508	6,538	1,115	1,278
Production taxes	5,039	6,408	7,607	2,933	2,853
Depreciation, depletion and amortization	160,762	158,893	110,859	101,105	98,457
Write-down of oil and gas properties	-	237,741	-	-	114,341
Non-cash derivative expenses	15,968	2,604	-	-	-
Bad debt expense (1)	-	2,343	-	-	-
Salaries, general and administrative expenses	13,190	13,004	12,725	10,764	8,636
Incentive compensation expense	851	523	1,722	1,510	763
Total operating expenses	272,483	475,588	180,925	150,799	252,646
Income (loss) from operations	105,012	(80,089)	201,013	67,616	(89,429)
Other (income) expenses:					
Interest expense	23,111	4,895	9,395	15,186	15,017
Merger expenses	-	25,785	1,297	-	-
Other income	(3,328)	(2,997)	(4,228)	(2,349)	(2,102)
Total other expenses	19,783	27,683	6,464	12,837	12,915
Net income (loss) before income taxes	85,229	(107,772)	194,549	54,779	(102,344)
Income tax provision (benefit):					
Current	-	(489)	450	25	23
Deferred	29,830	(35,908)	67,642	17,688	(35,843)
Total income tax provision (benefit)	29,830	(36,397)	68,092	17,713	(35,820)
Net income (loss)	$55,399	($71,375)	$126,457	$37,066	($66,524)
Earnings and dividends per common share:					
Basic net income (loss) per common share	$2.10	($2.73)	$4.90	$1.61	($3.23)
Diluted net income (loss) per common share	$2.09	($2.73)	$4.80	$1.58	($3.23)
Cash dividends declared	-	-	-	-	-
Cash Flow Data:					
Net cash provided by operating activities	$222,921	$315,617	$302,082	$123,010	$118,014
Net cash used in investing activities	(216,600)	(656,847)	(258,637)	(158,567)	(265,682)
Net cash provided by financing activities	8,133	275,828	17,461	42,327	147,714
Balance Sheet Data (at end of period):					
Working capital (deficit)	($1,213)	($18,097)	$53,065	$12,509	($3,340)
Oil and gas properties, net	1,047,936	993,906	747,574	587,661	492,349
Total assets	1,179,371	1,101,783	944,104	706,958	581,134
Long-term debt, less current portion	431,000	426,000	148,000	134,000	289,936
Stockholders' equity	577,488	530,025	587,577	452,870	213,131

(1) Relates to 100% allowance for production receivable due from Enron North America Corp recorded during the fourth quarter of 2001.

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

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, 2002. 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."

Overview

We are an independent oil and gas company engaged in the acquisition, exploration, development and operation of oil and gas properties onshore and in the Gulf of Mexico and in several basins in the Rocky Mountains. We have been active in the Gulf Coast Basin since 1973, which gives us extensive geophysical, technical and operational expertise in this area.

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 was attributable to a variety of factors impacting supply and demand, including weather conditions, political events and economic events we can neither control nor predict.

Over the last several years, we have financed our drilling budget primarily with cash flow from operating activities. We accessed the credit markets to complete the $300 million property acquisition from Conoco, Inc. on December 31, 2001.

Based on our outlook of commodity prices and our estimated production, we expect to finance our 2003 capital program with cash flow from operating activities. Our 2003 capital expenditures budget is approximately $240 million, or 19% more than our 2002 capital expenditures, excluding acquisitions and capitalized interest and general and administrative expenses. To the extent that 2003 cash flow from operating activities exceeds our estimated 2003 capital expenditures, we plan to pay down a portion of our existing debt. If cash flow from operating activities during 2003 is not sufficient to fund estimated 2003 capital expenditures, we believe that our bank credit facility, under which we have $160.9 million of available borrowings at March 10, 2003, will provide us with adequate liquidity.

Results of Operations

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,		
	2002	2001	2000
Production:			
Oil (MBbls)	6,237	4,023	4,449
Gas (MMcf)	67,027	68,236	72,239
Oil and gas (MMcfe)	104,449	92,374	98,933
Average sales prices: (1)			
Oil (per Bbl)	$25.00	$25.62	$26.66
Gas (per Mcf)	3.31	4.29	3.64
Oil and gas (per Mcfe)	3.61	4.28	3.86
Average costs (per Mcfe):			
Normal lease operating expenses (2)	$0.58	$0.51	$0.42
Salaries, general and administrative expenses	0.13	0.14	0.13
DD&A on oil and gas properties	1.52	1.70	1.10
Reserves at December 31:			
Oil (MBbls)	52,019	55,391	33,625
Gas (MMcf)	438,652	442,669	398,524
Oil and gas (MMcfe)	750,766	775,015	600,274
Present value of estimated future net cash flows before income taxes (in thousands)	$1,784,761	$1,038,797	$2,941,790
Standardized measure of discounted future net cash flows (in thousands)	$1,374,710	$908,576	$1,982,749

(1) Includes the cash effects of hedging.
(2) Excludes major maintenance expenses.

2002 Compared to 2001. For the year 2002, we reported net income totaling $55.4 million, or $2.09 per share, compared to net loss for the year ended December 31, 2001 of $71.4 million, or $2.73 per share. The variance in annual results was due to the following components:

Production. During 2002, production volumes increased 13% to 104.4 Bcfe compared to 92.4 Bcfe produced during 2001. Oil production during 2002 increased 55% to approximately 6.2 million barrels compared to 2001 oil production of 4.0 million barrels, while natural gas production during 2002 totaled approximately 67.0 billion cubic feet compared to 68.2 billion cubic feet produced during 2001. The increase in overall 2002 production, compared to 2001, was primarily the result of our December 31, 2001 acquisition of eight producing properties from Conoco, Inc.

Prices. Prices realized during 2002 averaged $25.00 per barrel of oil and $3.31 per Mcf of gas compared to 2001 average realized prices of $25.62 per barrel of oil and $4.29 per Mcf of gas. On a gas equivalent basis, average 2002 prices were 16% lower than prices realized during 2001. All unit pricing amounts include the cash effects of hedging.

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. Hedging transactions increased the average price we received during 2002 for oil by $0.13 per barrel and increased the average price we received for natural gas by $0.08 per Mcf, compared to a net increase of $0.37 per barrel and a net decrease of $0.04 per Mcf realized during 2001.

Oil and Gas Revenue. As a result of lower realized prices, offset in part by a 13% growth in production, oil and gas revenue declined 5% to $377.5 million in 2002 from $395.5 million during 2001.

Expenses. During 2002, we incurred normal lease operating expenses of $61.0 million, compared to $47.6 million incurred during 2001. On a unit of production basis, 2002 normal lease operating expenses were $0.58 per Mcfe as compared to $0.51 per Mcfe for 2001. Our December 2001 acquisition of eight producing properties increased the number of producing wells and significantly increased the volume of oil production from 2001 levels. The combination of these factors contributed to the increase in normal lease operating expenses during 2002.

Production taxes for 2002 decreased to \$5.0 million from \$6.4 million in 2001 primarily due to decreased production volumes from onshore properties and a decrease in the Louisiana severance tax rate for natural gas effective July 1, 2002.

Depreciation, depletion and amortization (DD&A) expense on oil and gas properties totaled \$158.3 million, or \$1.52 per Mcfe, during 2002 compared to \$157.2 million, or \$1.70 per Mcfe, for 2001. DD&A for the year ended December 31, 2002 was positively impacted by higher period-end oil and gas prices for 2002.

We follow the full cost method of accounting for oil and gas properties. Based upon low oil and gas prices at the end of the third quarter of 2001, we recognized a ceiling test write-down of our oil and gas properties totaling \$237.7 million, or \$154.5 million after taxes. This expense did not impact our cash flow from operating activities, but did reduce net income.

Interest expense for 2002 increased to \$23.1 million, compared to \$4.9 million during 2001 due to the issuance of the 8¼% Senior Subordinated Notes and borrowings under our bank credit facility to finance our \$300 million acquisition in December 2001.

Due to Enron Corp's financial difficulties, during the fourth quarter of 2001, we recorded a 100% allowance for a production accounts receivable due from Enron North America Corp. This allowance resulted in a 2001 non-cash charge of approximately \$2.3 million to bad debt expense.

Our merger with Basin Exploration, Inc. was completed on February 1, 2001. In connection with the completion of the merger, we incurred expenses during 2001 totaling \$25.8 million.

Reserves. At December 31, 2002, our estimated proved oil and gas reserves totaled 750.8 Bcfe, compared to December 31, 2001 reserves of 775.0 Bcfe. The 3% decline in estimated proved reserves during 2002 was the combined result of 2002's record production, the exploration portion of our drilling program providing less than expected reserve additions and the lack of a material acquisition during 2002. Estimated proved natural gas reserves totaled 438.7 Bcf and estimated proved oil reserves totaled 52.0 MMBbls at the end of 2002.

The reserve estimates were prepared by independent petroleum consultants in accordance with guidelines established by the SEC. Adherence to these guidelines limited us in booking reserves on successfully drilled wells to the extent of the base of known productive sands. Actual limits of the productive sands will ultimately be determined through production or additional drilling.

Our present values of estimated future net cash flows before income taxes were \$1.8 billion and \$1.0 billion at December 31, 2002 and 2001, respectively. You should not assume that the present values of estimated future net cash flows represent the fair value of our estimated oil and natural gas reserves. As required by the SEC, we determine the present value of estimated 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 \$30.41 per barrel and \$4.86 per Mcf for 2002 and \$18.64 per barrel and \$2.79 per Mcf for 2001.

2001 Compared to 2000. For the year 2001, we reported a net loss totaling \$71.4 million, or \$2.73 per share, compared to net income for the year ended December 31, 2000 of \$126.5 million, or \$4.80 per share. The variance in annual results was due to the following components:

Production. During 2001, production volumes totaled 92.4 Bcfe compared to 98.9 Bcfe produced during 2000. Natural gas production during 2001 decreased 6% to approximately 68.2 billion cubic feet compared to 2000 gas production of 72.2 billion cubic feet, while oil production during 2001 totaled approximately 4.0 million barrels compared to 4.4 million barrels produced during 2000. The decrease in 2001 production rates, compared to 2000, was the combined result of our 2001 drilling program providing less than expected production growth and normal production declines.

Prices. Prices realized during 2001 averaged \$25.62 per barrel of oil and \$4.29 per Mcf of gas compared to 2000 average realized prices of \$26.66 per barrel of oil and \$3.64 per Mcf of gas. All unit pricing amounts include the cash effects of hedging.

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. Hedging transactions increased the average price we received during 2001 for oil by \$0.37 per barrel and decreased the average price received for natural gas by \$0.04 per Mcf, compared to net decreases of \$3.55 per barrel and \$0.46 per Mcf realized during 2000.

Oil and Gas Revenue. As a result of 11% higher realized prices on a Mcfe basis, oil and gas revenue increased 4% to \$395.5 million in 2001 from \$381.9 million during 2000.

Expenses. Normal lease operating expenses during 2001 increased to $47.6 million, compared to $41.5 million during 2000. On a unit of production basis, 2001 normal lease operating expenses were $0.51 per Mcfe as compared to $0.42 per Mcfe for 2000. The increase in normal lease operating expenses was due primarily to industry-wide increases in the costs of oil field products and services.

Production taxes for 2001 decreased to $6.4 million from $7.6 million in 2000 primarily due to decreased production volumes from onshore properties.

Depreciation, depletion and amortization expense on oil and gas properties totaled $157.2 million, or $1.70 per Mcfe, compared to $109.2 million, or $1.10 per Mcfe, for 2000. Higher drilling costs, higher unit reserve replacement costs and declining oil and gas prices used in computing amortization under the future gross revenue method contributed to the increased DD&A expense during 2001.

As a result of having no outstanding obligations on our bank debt for a majority of 2001 and an increase in capitalized interest on unevaluated properties, interest expense for 2001 decreased to $4.9 million, compared to $9.4 million during 2000.

Reserves. At December 31, 2001, our estimated proved oil and gas reserves totaled 775.0 Bcfe, compared to December 31, 2000 reserves of 600.3 Bcfe. Estimated proved gas reserves grew to 442.7 Bcf at the end of 2001 from 398.5 Bcf at year-end 2000, and estimated proved oil reserves grew to 55.4 MMBbls at the end of 2001 from 33.6 MMBbls at the beginning of the year.

The increases in our 2001 estimated proved reserve volumes were primarily attributable to drilling results and acquisitions during the year. The reserve estimates were prepared by independent petroleum consultants in accordance with guidelines established by the SEC. Adherence to these guidelines limited us in booking reserves on successfully drilled wells to the extent of the base of known productive sands. Actual limits of the productive sands will ultimately be determined through production or additional drilling.

Our present values of estimated future net cash flows before income taxes were $1.0 billion and $2.9 billion at December 31, 2001 and 2000, respectively. 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 $18.64 per barrel and $2.79 per Mcf for 2001 and $27.30 per barrel and $9.97 per Mcf for 2000.

Liquidity and Capital Resources

Cash Flow and Working Capital. Net cash flow provided by operating activities for 2002 was $222.9 million compared to $315.6 million reported in 2001. The decrease in net cash flow provided by operating activities was primarily attributable to changes in working capital between periods and lower oil and gas revenue caused by 16% lower average realized prices on a gas equivalent basis during 2002, offset in part by a 13% increase in production volumes for the corresponding period.

Net cash flow used in investing activities totaled $216.6 million and $656.8 million during 2002 and 2001, respectively, which primarily represents our investment in oil and gas properties.

Net cash flow provided by financing activities totaled $8.1 million and $275.8 million for the years ended December 31, 2002 and 2001, respectively. The higher cash flow provided by financing activities during 2001 was the result of the issuance of $200.0 million 8¼% Senior Subordinated Notes due 2011 and $100.0 million of borrowings under the amended credit facility in connection with the December 2001 property acquisition, partially offset by a $53.0 million repayment of debt made in connection with the termination of Basin Exploration's bank credit facility concurrent with the closing of the merger on February 1, 2001. As a result of these activities, cash and cash equivalents increased from $13.2 million as of December 31, 2001 to $27.6 million as of December 31, 2002.

We had a working capital deficit at December 31, 2002 of $1.2 million. We believe that our working capital balance is not a good indication of our liquidity because it fluctuates as a result of borrowings or repayments under our credit facility and the timing of capital expenditures.

Capital Expenditures. Capital expenditures during 2002 totaled $215.6 million and included $10.5 million of capitalized general and administrative costs, net of overhead reimbursements, and $8.5 million of capitalized interest. These investments were financed by cash flows from operating activities, borrowings under our bank credit facility and working capital.

Our 2003 capital expenditures budget, excluding acquisitions and capitalized interest and general and administrative expenses, is approximately $240 million, or 19% more than our 2002 capital expenditures, excluding acquisitions and capitalized interest and general and administrative expenses. Based on our outlook of commodity prices and our estimated production, we expect to finance our 2003 capital program with cash flow from operating activities.

To the extent that 2003 cash flow from operating activities exceeds our estimated 2003 capital expenditures, we plan to pay down a portion of our existing debt. If cash flow from operating activities during 2003 is not sufficient to fund estimated 2003 capital expenditures, we believe that our bank credit facility will provide us with adequate liquidity.

We do not budget acquisitions; however, we are currently evaluating several opportunities that fit our specific acquisition profile. One or a combination of certain of these possible transactions could fully utilize our existing sources of capital. Although we have no 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. The publicly disclosed deteriorating financial conditions and recently reduced credit ratings of certain purchasers of production increase the possibility that 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 letters of credit, guarantees and prepayments 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.

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. During 2002, proved reserve additions were less than volumes produced.

Bank Credit Facility. At December 31, 2002, we had $131.0 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 $300 million, with availability of an additional $160.9 million in borrowings as of March 10, 2003. 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.

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 $350 million, which is adjusted for future earnings and cash proceeds from equity offerings after September 30, 2001. 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."

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, 2002. We have no "off-balance sheet" financing arrangements.

	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
8¾% Senior Subordinated Notes due 2007 ..	100,000	-	-	100,000	-
Bank credit facility (1)	131,000	-	131,000	-	-
Letters of credit (1)	13,084	-	13,084	-	-
Pinedale work commitment (2)	20,914	-	20,914	-	-
Operating lease obligations	2,574	947	1,497	130	-
Total Contractual Obligations and Commitments	$467,572	$947	$166,495	$100,130	$200,000

(1) The bank credit facility and related letters of credit mature on December 20, 2004.
(2) Work commitment for $28 million and the drilling of five wells in the Rocky Mountains.

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

Basis of Presentation. The financial statements include our accounts and the accounts of our wholly owned subsidiary. All intercompany balances and transactions have been eliminated.

Changes in Accounting Principles. Effective January 1, 2003, management elected to change to the Units of Production method of amortizing proved oil and gas property costs. Under this method, the quarterly provision for DD&A will be 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. As a result of the change in accounting principle, we recognized a cumulative transition adjustment of $4.0 million, which will be a non-cash charge against our 2003 net income.

In addition, management elected to begin recognizing gas production revenue under the Entitlement method of accounting effective January 1, 2003. Under this method, revenue is deferred for gas 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 is immaterial.

Full Cost Method. We use the full cost method of accounting for our oil and gas properties. Under this method, all acquisition and development 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 amortized our investment in oil and gas properties through DD&A using the future gross revenue method. Under this method, the annual provision for DD&A is computed by dividing revenue earned during the period by future gross revenues at the beginning of the period, and applying the resulting rate to the cost of oil and gas properties, including estimated future development, restoration, dismantlement and abandonment costs. Effective January 1, 2003, management elected to change to the Units of Production method of amortizing capitalized oil and gas property costs. See "— Changes in Accounting Principles" above.

We capitalize a portion of the interest costs incurred on our debt. Capitalized interest is calculated using the amount of our unevaluated property and our effective borrowing rate. We also capitalize the portion of employee, general and administrative costs that are attributable to our acquisition, exploration and development activities.

Under the full cost method of accounting, we are required to periodically compare the present value of estimated future net cash flows from proved reserves (based on period-end commodity prices) to the net capitalized costs of proved oil and gas properties. 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.

Reserves. Independent petroleum and geological engineers prepare estimates of our oil and gas reserves. Proved reserves and the cash flow related to these reserves are estimated based upon a combination of historical data and estimates of future activity. Reserve estimates are used in calculating DD&A and in preparation of the full cost ceiling test.

Abandonment Liabilities. In July 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 143, "Accounting for Asset Retirement Obligations," effective for fiscal years beginning after June 15, 2002. This statement will require us to record our estimate of the fair value of liabilities related to future asset retirement obligations in the period the obligation is incurred. 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 credit 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 obligation does not give consideration to the value the related assets could have to other parties.

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 depreciation, depletion and amortization, unevaluated property costs, estimated future net cash flow, 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, 2002, we had net deferred taxes of $58.0 million, which amount 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-7.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including adverse changes in commodity prices and interest rates, as discussed below.

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 from 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 production quantities can be hedged without the consent of the board of directors.

Hedging. 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 gas, which represented approximately 68% and 37%, respectively, of our oil and gas production for the year. During 2001, we realized a net reduction in revenue from our hedging transactions of $1.8 million. Our contracts totaled 1,278 MBbls of oil and 29,300 BBtus of gas, which represented approximately 32% and 43%, respectively, of our oil and gas production for the year. The net reduction in revenue from hedging transactions for 2000 was $47.9 million. Our contracts totaled 1,868 MBbls of oil and 29,303 BBtus of gas, which represented approximately 42% and 41%, respectively, of our oil and gas production for that year.

Our gas put contracts are with Bank of America, N.A, J. Aron & Company and Bank of Montreal. 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 prices fall below the agreed upon floor price, while allowing us to fully participate in commodity prices above that floor.

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. Accumulated other comprehensive income on December 31, 2002 included $2.4 million related to the swap contract that will be amortized during 2003.

We entered into additional natural gas hedges during January 2003 under fixed-price swap contracts based upon deliveries in the Rocky Mountains and put contracts for Gulf Coast Basin production. The swap contracts effectively hedge 10,000 MMBtu per day at a swap price of $3.68 from April 2003 until December 2003 and 15,000 MMBtu per day at a swap price of $3.42 from January 2004 until December 2005. The put contracts effectively hedge 25,000 MMBtu per day with a floor price of $3.50 from March 2003 until December 2003. The put contracts' cost of approximately $0.5 million will be charged to earnings as the contracts settle.

During 2002, we recognized $16.0 million of non-cash derivative expenses, of which $13.2 million represents amortization of the historical cost associated with oil and gas put contracts that settled during the year.

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 NYMEX futures contracts for the three days prior to the settlement date.

The following tables show our hedging positions as of March 1, 2003:

	Natural Gas Puts		
	Volume (BBtus)	Average Floor	Unamortized Cost (millions)
2003	30,600	$3.12	$4.3

	Fixed Price Gas Swaps	
	Volume (BBtus)	Price
2003	2,750	$3.68
2004	5,490	3.42
2005	5,475	3.42

Adoption of SFAS No. 133. Under SFAS No. 133, as amended, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Our hedges are designated as cash flow hedges when entered into. 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.

We adopted SFAS No. 133 effective January 1, 2001. Upon adoption of SFAS No. 133, as amended, the after-tax increase in fair value over historical cost of our oil put contracts of $1.7 million was a transition adjustment that was recorded as a gain in equity through other comprehensive income. In addition, the fair market value of the fixed price gas swap was recorded as a liability and the corresponding after-tax loss of $27.8 million was recorded in equity through other comprehensive income. Our put contracts at

December 31, 2002 were considered effective cash flow hedges and changes in fair value of these contracts are reflected in other comprehensive income, net of related taxes.

We use sensitivity analysis techniques to evaluate the hypothetical effect that changes in the market prices of oil and gas may have on the fair value of our commodity hedging instruments. We had open gas put positions at December 31, 2002 with a positive fair value of $0.9 million. A 10% increase in the underlying price of natural gas as of March 1, 2003, would have reduced the fair value of our gas puts by approximately $0.4 million. The fair value of our puts was based upon quotes obtained from the counterparties to the hedge agreements.

Interest Rate Risk

At December 31, 2002, Stone had long-term debt outstanding of $431.0 million. Of this amount, $300 million, or 70%, bears interest at fixed rates averaging 8.4%. The remaining $131.0 million of debt outstanding at the end of 2002 bears interest at a floating rate. Because the majority of our long-term debt at December 31, 2002 was at fixed rates, we consider our interest rate exposure at such date to be minimal. At December 31, 2002, we had no open interest rate hedge positions to reduce our exposure to changes in interest rates.

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, 2002. At December 31, 2002, the fair value of the 8¾% Senior Subordinated Notes due 2007 totaled $103.5 million and the fair value of the 8¼% Senior Subordinated Notes due 2011 totaled $208.0 million. The fair values of the Notes have been estimated based on quotes from brokers.

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 accountants on our accounting or financial reporting that would require our independent accountants to qualify or disclaim their report on our financial statements, or otherwise require disclosure in this annual report on Form 10-K.

On June 26, 2002, we dismissed Arthur Andersen LLP, also referred to as Andersen, as our independent accountants effective as of that date. The decision to dismiss Andersen was recommended by the Audit Committee of the Board of Directors and was approved by the Board of Directors on June 26, 2002.

Andersen's report on Stone's financial statements for the fiscal year ended December 31, 2001 did not contain an adverse opinion or disclaimer of opinion and was not qualified or modified as to uncertainty or audit scope. In addition, there were no modifications as to accounting principles except that the audit report of Andersen for the fiscal year ended December 31, 2001 contained an explanatory paragraph with respect to the change in the method of accounting for derivative instruments effective January 1, 2001 as required by the FASB. During the fiscal year ended December 31, 2001 and the period from January 1, 2002 through the date of Andersen's termination, there were no disagreements between us and Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of Andersen, pursuant to Item 304(a)(1) of Regulation S-K, would have caused it to make reference to the subject matter of the disagreements in its report.

In June 2002, as required under the regulations of the SEC, we provided Andersen with a copy of our disclosure in connection with this matter and requested Andersen to furnish us with a letter addressed to the SEC stating whether it agreed with our statements and, if not, stating the respects in which it did not agree. Andersen's letter was filed as Exhibit 16.1 to our Current Report on Form 8-K filed with the SEC on June 27, 2002.

Effective June 26, 2002, we engaged Ernst & Young LLP as our new independent accountants for the fiscal year ended December 31, 2002. The decision to appoint Ernst & Young LLP was recommended by the Audit Committee of the Board of Directors and was approved by the Board of Directors on June 26, 2002.

PART III

For additional information concerning Item 10. Directors and Executive Officers of the Registrant, Item 11. Executive Compensation, Item 12. Security Ownership of Certain Beneficial Owners and Management, and Item 13. Certain Relationships and Related Transactions, see the Definitive Proxy Statement of Stone Energy Corporation relating to the Annual Meeting of Stockholders to be held on May 21, 2003, which will be filed with the SEC and is incorporated herein by reference. For information concerning Item 10, see also "Part I, Item 4A. – Executive Officers of the Registrant," set forth above in this Form 10-K.

ITEM 14. 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 the design and operation of Stone's disclosure controls and procedures as of a date within 90 days before the filing of this annual report on Form 10-K. Based on this evaluation, our chief executive officer and chief financial officer believe:

- Stone's disclosure controls and procedures are designed to ensure that information required to be disclosed by Stone in the reports 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 material information 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.

Changes in Internal Controls

There were no significant changes in Stone's internal controls or, to the knowledge of our chief executive officer and chief financial officer, in other factors that could significantly affect these controls subsequent to the date of their evaluation, nor were there any significant deficiencies or material weaknesses in Stone's internal controls. As a result, no corrective actions were required or undertaken.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

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

The following consolidated financial statements, notes to the consolidated financial statements and the Report of Independent Auditors thereon are included on pages F-1 through F-20 of this Form 10-K:

Report of Independent Auditors

Consolidated Balance Sheet as of December 31, 2002 and 2001

Consolidated Statement of Operations for the three years in the period ended December 31, 2002

Consolidated Statement of Cash Flows for the three years in the period ended December 31, 2002

Consolidated Statement of Changes in Stockholders' Equity for the three years in the period ended December 31, 2002

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).

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 -- Indenture between Stone Energy Corporation and Texas Commerce Bank, National Association dated as of September 19, 1997 (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-4 dated October 22, 1997 (File No. 333-38425)).

4.3 -- 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)).

4.4 -- 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)).

†10.1 -- Stone Energy Corporation 1993 Nonemployee Directors' Stock Option Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).

†10.2 -- Deferred Compensation and Disability Agreements between TSPC and D. Peter Canty dated July 16, 1981, and between TSPC and Joe R. Klutts 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)).

†10.3 -- 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)).

†10.4 -- 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)).

†10.5 -- Stone Energy Corporation 2000 Amended and Restated Stock Option Plan (incorporated by reference to Appendix A to the Registrant's Definitive Proxy Statement on Schedule 14A for Stone's 2000 Annual Meeting of Stockholders (File No. 001-12074)).

†10.6 -- 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)).

†10.7 -- 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)).

10.8 -- Fourth Amended and Restated Credit Agreement between the Registrant, the financial institutions named therein and Bank of America, N.A., as administrative agent, dated as of December 20, 2001 (incorporated by reference to Exhibit 10.3 to the Registrant's Registration Statement on Form S-4 (Registration No. 333-81380)).

†10.9 -- 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. 333-64448)).

†*10.10 -- Stone Energy Corporation Revised 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).

*21.1 -- Subsidiaries of the Registrant.

*23.1 -- Consent of Ernst & Young LLP.

*23.2 -- Consent of Atwater Consultants, Ltd.

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

*23.4 -- Consent of Ryder Scott Company.

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* Filed herewith.
† Identifies management contracts and compensatory plans or arrangements.

(b) Reports on Form 8-K

Stone filed the following reports on Form 8-K during the fourth quarter of 2002:

Date of Event Reported	Item Reported
November 12, 2002	Item 9*
December 23, 2002	Item 7 & 9*

* The information in the Forms 8-K furnished pursuant to Item 9 is not considered to be "filed" for the purposes of Section 18 of the Exchange Act 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, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Lafayette, State of Louisiana, on the 19th day of March 2003.

STONE ENERGY CORPORATION

By: /s/ D. Peter Canty
D. Peter Canty
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 19, 2003
/s/ Joe R. Klutts Joe R. Klutts	Vice Chairman of the Board	March 19, 2003
/s/ D. Peter Canty D. Peter Canty	President, Chief Executive Officer and Director (principal executive officer)	March 19, 2003
/s/ James H. Prince James H. Prince	Senior Vice President, Chief Financial Officer and Treasurer (principal financial officer)	March 19, 2003
/s/ J. Kent Pierret J. Kent Pierret	Vice President, Controller and Chief Accounting Officer (principal accounting officer)	March 19, 2003
/s/ Peter K. Barker Peter K. Barker	Director	March 19, 2003
/s/ Robert A. Bernhard Robert A. Bernhard	Director	March 19, 2003
/s/ B.J. Duplantis B.J. Duplantis	Director	March 19, 2003
/s/ Raymond B. Gary Raymond B. Gary	Director	March 19, 2003
/s/ John P. Laborde John P. Laborde	Director	March 19, 2003
/s/ Richard A. Pattarozzi Richard A. Pattarozzi	Director	March 19, 2003
/s/ David R. Voelker David R. Voelker	Director	March 19, 2003

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS

To the Stockholders of
Stone Energy Corporation:

We have audited the accompanying consolidated balance sheets of Stone Energy Corporation (a Delaware corporation) and subsidiary as of December 31, 2002 and 2001, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Stone Energy Corporation and subsidiary as of December 31, 2002 and 2001, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

Ernst & Young LLP

New Orleans, Louisiana
February 28, 2003

STONE ENERGY CORPORATION
CONSOLIDATED BALANCE SHEET
(Dollar amounts in thousands, except per share amounts)

	December 31, 2002	December 31, 2001
ASSETS		
Current assets:		
Cash and cash equivalents	$27,609	$13,155
Accounts receivable	74,800	46,987
Fair value of put contracts	859	26,207
Other current assets	3,601	1,832
Total current assets	106,869	88,181
Oil and gas properties—full cost method of accounting:		
Proved, net of accumulated depreciation, depletion and amortization of $1,177,024 and $1,015,455, respectively	940,463	880,534
Unevaluated	107,473	113,372
Building and land, net of accumulated depreciation of $735 and $598, respectively	5,238	5,352
Fixed assets, net of accumulated depreciation of $11,028 and $9,387, respectively	5,452	4,883
Other assets, net of accumulated depreciation and amortization of $3,253 and $1,932, respectively	13,876	9,461
Total assets	$1,179,371	$1,101,783
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$72,012	$69,197
Undistributed oil and gas proceeds	29,027	23,741
Deferred taxes	-	5,312
Fair value of swap contract	-	2,194
Other accrued liabilities	7,043	5,834
Total current liabilities	108,082	106,278
Long-term debt	431,000	426,000
Production payments	1,062	4,323
Deferred taxes	59,604	30,244
Fair value of swap contract	-	3,619
Other long-term liabilities	2,135	1,294
Total liabilities	601,883	571,758
Common stock, $.01 par value; authorized 100,000,000 shares; issued and outstanding 26,337,532 and 26,190,270 shares, respectively	263	262
Treasury stock (32,882 and 39,650 shares, respectively, at cost)	(1,706)	(2,057)
Additional paid-in capital	453,176	449,111
Retained earnings	130,523	75,213
Accumulated other comprehensive income (loss)	(4,768)	7,496
Total stockholders' equity	577,488	530,025
Total liabilities and stockholders' equity	$1,179,371	$1,101,783

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

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

	Year Ended December 31,		
	2002	2001	2000
Operating revenue:			
Oil production	$155,913	$103,053	$118,628
Gas production	221,582	292,446	263,310
Total operating revenue	377,495	395,499	381,938
Operating expenses:			
Normal lease operating expenses	60,952	47,564	41,474
Major maintenance expenses	15,721	6,508	6,538
Production taxes	5,039	6,408	7,607
Depreciation, depletion and amortization	160,762	158,893	110,859
Write-down of oil and gas properties	-	237,741	-
Salaries, general and administrative expenses	13,190	13,004	12,725
Incentive compensation expense	851	523	1,722
Non-cash derivative expenses	15,968	2,604	-
Bad debt expense	-	2,343	-
Total operating expenses	272,483	475,588	180,925
Income (loss) from operations	105,012	(80,089)	201,013
Other (income) expenses:			
Interest	23,111	4,895	9,395
Merger expenses	-	25,785	1,297
Other income	(3,328)	(2,997)	(4,228)
Total other expenses	19,783	27,683	6,464
Net income (loss) before income taxes	85,229	(107,772)	194,549
Income tax provision (benefit):			
Current	-	(489)	450
Deferred	29,830	(35,908)	67,642
Total income taxes	29,830	(36,397)	68,092
Net income (loss)	$55,399	($71,375)	$126,457
Earnings (loss) per common share:			
Basic earnings (loss) per share	$2.10	($2.73)	$4.90
Diluted earnings (loss) per share	$2.09	($2.73)	$4.80
Average shares outstanding	26,326	26,111	25,804
Average shares outstanding assuming dilution	26,494	26,111	26,335

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS
(Dollar amounts in thousands)

	Year Ended December 31,		
	2002	2001	2000
Cash flows from operating activities:			
Net income (loss)	$55,399	($71,375)	$126,457
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	160,762	158,893	110,859
Deferred income tax provision (benefit)	29,830	(35,908)	67,642
Non-cash effect of production payments	(2,988)	(6,199)	(5,784)
Write-down of oil and gas properties	-	237,741	-
Non-cash derivative expenses	15,968	2,604	-
Other non-cash expenses	706	1,002	923
	259,677	286,758	300,097
Decrease in marketable securities	-	300	34,606
(Increase) decrease in accounts receivable	(27,813)	48,735	(45,661)
(Increase) decrease in other current assets	(253)	733	2,040
Increase (decrease) in other accrued liabilities	6,495	(13,279)	15,258
Investment in derivative contracts	(15,301)	(6,466)	(4,999)
Other	116	(1,164)	741
Net cash provided by operating activities	222,921	315,617	302,082
Cash flows from investing activities:			
Investment in oil and gas properties	(213,566)	(657,327)	(259,074)
Sale of proved properties	3,304	-	-
Sale of unevaluated properties	600	1,366	4,302
Building additions and renovations	(23)	-	(1,160)
Increase in other assets	(6,915)	(886)	(2,705)
Net cash used in investing activities	(216,600)	(656,847)	(258,637)
Cash flows from financing activities:			
Proceeds from borrowings	22,000	131,000	59,500
Repayment of debt	(17,000)	(53,000)	(45,500)
Proceeds from issuance of 8¼% notes	-	200,000	-
Deferred financing costs	(287)	(6,794)	(200)
Proceeds from exercise of stock options	3,420	4,822	4,404
Purchase of treasury stock	-	(200)	(743)
Net cash provided by financing activities	8,133	275,828	17,461
Net increase (decrease) in cash and cash equivalents	14,454	(65,402)	60,906
Cash and cash equivalents, beginning of year	13,155	78,557	17,651
Cash and cash equivalents, end of year	$27,609	$13,155	$78,557
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$22,495	$3,992	$8,793
Income taxes	-	-	450

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(Dollar amounts in thousands)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balance, December 31, 1999	$257	$ -	$432,482	$20,131	$ -	$452,870
Net income	-	-	-	126,457	-	126,457
Exercise of stock options	3	-	4,401	-	-	4,404
Stock compensation plans	1	-	2,442	-	-	2,443
Tax benefit from stock option exercises	-	-	3,657	-	-	3,657
Purchase of treasury stock	-	(3,185)	-	-	-	(3,185)
Issuance and vesting of restricted stock	-	-	931	-	-	931
Retirement of treasury stock	(1)	3,185	(3,184)	-	-	-
Balance, December 31, 2000	260	-	440,729	146,588	-	587,577
Net loss	-	-	-	(71,375)	-	(71,375)
Cumulative effect of accounting change for derivatives, net of tax benefit	-	-	-	-	(26,114)	(26,114)
Net change in fair value of derivatives, net of taxes	-	-	-	-	33,720	33,720
Effect of change in accounting treatment for swaps, net of tax benefit	-	-	-	-	(110)	(110)
Total comprehensive loss						(63,879)
Exercise of stock options	2	-	6,677	-	-	6,679
Tax benefit from stock option exercises	-	-	1,499	-	-	1,499
Purchase of treasury stock	-	(2,057)	-	-	-	(2,057)
Issuance and vesting of restricted stock	-	-	206	-	-	206
Balance, December 31, 2001	262	(2,057)	449,111	75,213	7,496	530,025
Net income	-	-	-	55,399	-	55,399
Net change in fair value of derivatives, net of tax benefit	-	-	-	-	(14,012)	(14,012)
Effect of accounting treatment for swaps, net of taxes	-	-	-	-	1,748	1,748
Total comprehensive income						43,135
Exercise of stock options	1	-	3,332	-	-	3,333
Tax benefit from stock option exercises	-	-	733	-	-	733
Issuance of treasury stock	-	351	-	(89)	-	262
Balance, December 31, 2002	$263	($1,706)	$453,176	$130,523	($4,768)	$577,488

The accompanying notes are an integral part of this statement.

(Dollar amounts in thousands, except per share and price amounts)

NOTE 1 — ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Stone Energy Corporation is an independent oil and gas company engaged in the acquisition, exploration, development, production and operation of oil and gas properties in the Gulf Coast Basin and Rocky Mountains. The Gulf Coast Basin represents our primary focal area of operation and has been throughout our existence.

We are headquartered in Lafayette, Louisiana, with additional offices in New Orleans, Louisiana, Houston, Texas and Denver, Colorado.

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

Merger with Basin Exploration:

On February 1, 2001, the stockholders of Stone Energy Corporation and Basin Exploration, Inc. voted in favor of, and thereby consummated, the combination of the two companies in a tax-free, stock-for-stock transaction accounted for under the Pooling-of-Interests method. Stone issued 7,436,652 shares of common stock. In addition, Stone assumed, and subsequently retired with cash on hand, $48,000 of Basin bank debt. The expenses incurred in relation to the merger totaled $25,785 and $1,297 in 2001 and 2000, respectively.

The following table reconciles certain of our pre-merger operating results with results reflecting the restatement of our financial statements under the Pooling-of-Interest method of accounting:

	2000		
	Stone	Effects of Pooling	As Reported
Revenue..............	$256,408	$125,530	$381,938
Net income...........	84,945	41,512	126,457

The financial information above does not purport to be indicative of the results of operations that would have occurred had the merger taken place at the beginning of the earliest period presented or future results of operations.

Basis of Presentation:

In accordance with the Pooling-of-Interests method of accounting for business combinations, the financial position and results of operations were combined to give effect to the combination of Stone and Basin as if the merger occurred at the beginning of the earliest period presented. Prior to the merger, Basin accounted for depreciation, depletion and amortization ("DD&A") of oil and gas properties using the units of production method. In connection with the restatement of Stone's financial statements on a Pooling-of-Interests basis, Basin's historical provision for DD&A was restated to conform to the future gross revenue method used by Stone. This restatement included related adjustments to Basin's historical reduction in carrying value of oil and gas properties recorded at the end of 1998 and their historical provision for income taxes. All periods presented reflect the effects of these adjustments.

We reclassified certain amounts in Basin's historical financial statements to conform to our 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, cost to abandon oil and gas properties, taxes, reserves of accounts receivable, capitalized employee, general and administrative costs, fair value 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, 2002 and 2001. The following table presents the carrying amounts and estimated fair values of our financial instruments at December 31, 2002 and 2001.

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
8¼% Senior Subordinated Notes due 2011 ..	$200,000	$208,000	$200,000	$201,880
8¾% Senior Subordinated Notes due 2007 ..	100,000	103,500	100,000	101,690
Put contracts..	859	859	26,207	26,207
Swap contract...	-	-	(5,813)	(5,813)

The following methods and assumptions were used to estimate the fair value of the financial instruments detailed above. The carrying amount of the bank debt approximated fair value because the interest rate is variable and reflective of market rates. The fair value of the Notes has been estimated based on quotes obtained from brokers. The fair value of the oil and gas price hedges are based upon quotes obtained from the counterparties to the hedge agreements.

Cash and Cash Equivalents:

We consider all 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 and development 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 is 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. Employee, general and administrative costs associated with production operations and general corporate activities are expensed in the period incurred.

Under the full cost method of accounting, we are required to periodically compare the present value of estimated future net cash flows from proved reserves (based on period-end commodity prices) to the net capitalized costs of proved oil and gas properties. 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. Due to the impact of low natural gas prices on September 30, 2001, we recorded a $237,741 reduction in the carrying value of our oil and gas properties.

Our investment in oil and gas properties is amortized through DD&A using the future gross revenue method whereby the annual provision is computed by dividing revenue earned during the period by future gross revenues at the beginning of the period, and applying the resulting rate to the cost of oil and gas properties, including estimated future development, restoration, dismantlement and abandonment costs. 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 method of amortizing proved oil and gas property costs. Under this method, the quarterly provision for DD&A will be 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. As a result of the change in accounting principle, we recognized a cumulative transition adjustment of $4,031 as a non-cash charge against our 2003 net income.

Oil and gas properties included $107,473 and $113,372 of unevaluated property and related costs that were not being amortized at December 31, 2002 and 2001, respectively. We believe that a majority of unevaluated properties at December 31, 2002 will be evaluated within 36 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 capitalized on unevaluated properties during the years ended December 31, 2002 and 2001 was $8,519 and $6,000, respectively.

On December 31, 2001, Stone completed the acquisition of eight producing oil and gas properties and related assets located in the Gulf of Mexico from Conoco, Inc. The purchase price of approximately $300,000 was financed with net proceeds from the December 2001 offering of $200,000 8¼% Senior Subordinated Notes due 2011 and borrowings under the bank credit facility. This acquisition was accounted for under the purchase method of accounting. Unevaluated property at December 31, 2002 and 2001 included $55,160 and $53,117, respectively, of costs attributable to these properties.

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.

Fixed Assets:

Fixed assets at December 31, 2002 and 2001 included approximately $3,553 and $2,593, 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, 2002 and 2001 included approximately $8,257 and $9,291, respectively, of deferred financing costs, net of accumulated amortization, related primarily to the issuance of the 8¾% and 8¼% Notes, shelf registration statement and the amendment of the credit facility (see Note 6 – Long-Term Debt). The costs associated with the Notes are being amortized over the life of the Notes using the effective interest method. 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:

Basic net income per share of common stock was calculated by dividing net income applicable to common stock by the weighted-average number of common shares outstanding during the year. Diluted net income per share of common stock was 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 granted to outside directors, officers and employees. There were approximately 168,000 and 531,000 weighted-average dilutive shares for the years ending December 31, 2002 and 2000, respectively. In 2001, all stock options were considered antidilutive because of the net loss incurred during the year. Options that were considered antidilutive because the exercise price of the stock exceeded the average price for the applicable period totaled approximately 1,064,000 shares and 279,000 shares during 2002 and 2000, respectively.

Gas Production Revenue:

We record as revenue only that portion of gas production sold and allocable to our ownership interest in the related well. Any gas production proceeds received in excess of our ownership interest are reflected as a liability in the accompanying balance sheet.

Revenue relating to net undelivered gas production to which we are entitled but for which we have not received payment are not recorded in the financial statements until such amounts are received. These amounts at December 31, 2002, 2001 and 2000 were immaterial.

Effective January 1, 2003, management elected to begin recognizing gas production revenue under the Entitlement method of accounting. Under this method, revenue is deferred for gas 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 to be recognized in 2003 is immaterial.

Income Taxes:

Income taxes are accounted for in accordance with the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standard (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 related to evaluated projects are capitalized and depreciated, depleted and amortized on the future gross revenue 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:

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 will require us to record the fair value of liabilities related to future asset retirement obligations in the period the obligation is incurred. We adopted SFAS No. 143 on January 1, 2003. Upon adoption, we recognized a credit for a cumulative transition adjustment of $5,256, net of tax, for existing asset retirement obligation liabilities, asset retirement costs and accumulated depreciation. In addition, we recorded a $32,080 increase in the capitalized costs of our oil and gas properties, net of accumulated depreciation, and recognized $76,270 in additional liabilities related to asset retirement obligations. As required by SFAS No. 143, our estimate of our asset retirement obligation does not give consideration to the value the related assets could have to other parties.

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. Instruments not qualifying for hedge accounting treatment are recorded in the balance sheet and changes in fair value are recognized in earnings. At December 31, 2002, our put contracts were considered effective cash flow hedges. (See Note 8 – Hedging Activities)

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:

	December 31,	
	2002	2001
Accounts Receivable:		
Other co-venturers	$10,224	$11,211
Trade	64,195	35,371
Officers and employees	6	4
Unbilled accounts receivable	375	401
	$74,800	$46,987

NOTE 3 — CONCENTRATIONS:

Sales to Major Customers

Our production is sold on month-to-month contracts at prevailing prices. 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,		
	2002	2001	2000
Conoco, Inc.	10%	(a)	(a)
Duke Energy Trading and Marketing LLC	24%	(a)	11%
El Paso Merchant Energy, LP	(a)	26%	13%
Enron North America Corp	-	19%	10%
Reliant Services, Inc.	11%	(a)	(a)

(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.

At December 31, 2002, Duke Energy Trading and Marketing LLC accounted for 42% of our trade accounts receivable balance.

During the fourth quarter of 2001, we recorded a $2,343 bad debt expense to reserve 100% of production accounts receivable from Enron North America Corp.

Production Volumes

Our four largest fields, South Pelto Block 23, Mississippi Canyon Block 109, Ewing Bank Block 305 and Eugene Island Block 243, accounted for approximately 38% of our total oil and gas production volumes during 2002.

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, which are located onshore and offshore the continental United States:

	Year Ended December 31,		
	2002	2001	2000
Oil and gas properties—			
Balance, beginning of year	$2,009,361	$1,368,084	$1,098,940
Costs incurred during the year:			
Capitalized—			
Acquisition costs, net of sales of unevaluated properties	14,071	328,778	15,086
Exploratory drilling	86,063	176,679	138,420
Development drilling	96,426	119,426	98,004
Employee, general and administrative costs and interest	19,603	16,720	19,234
Less: overhead reimbursements	(564)	(326)	(1,600)
Total costs incurred during year	215,599	641,277	269,144
Balance, end of year	$2,224,960	$2,009,361	$1,368,084
Charged to expense—			
Operating costs:			
Normal lease operating expenses	$60,952	$47,564	$41,474
Major maintenance expenses	15,721	6,508	6,538
Total operating costs	76,673	54,072	48,012
Production taxes	5,039	6,408	7,607
	$81,712	$60,480	$55,619
Unevaluated oil and gas properties—			
Costs incurred during year:			
Acquisition costs	$11,872	$77,311	$22,760
Exploration costs	6,238	-	6,229
	$18,110	$77,311	$28,989
Accumulated depreciation, depletion and amortization—			
Balance, beginning of year	($1,015,455)	($620,510)	($511,279)
Provision for depreciation, depletion and amortization	(158,265)	(157,204)	(109,231)
Sale of proved properties	(3,304)	-	-
Write-down of oil and gas properties	-	(237,741)	-
Balance, end of year	($1,177,024)	($1,015,455)	($620,510)
Net capitalized costs (proved and unevaluated)	$1,047,936	$993,906	$747,574
DD&A per Mcfe	$1.52	$1.70	$1.10

At December 31, 2002 and 2001, unevaluated oil and gas properties of $107,473 and $113,372, respectively, were not subject to depletion. Of the $107,473 in unevaluated costs at December 31, 2002, $18,110 was incurred in 2002 and $89,363 was incurred in prior years. We believe that a majority of unevaluated properties will be evaluated within 36 months.

Effective January 1, 2003, management elected to change to the Units of Production method of amortizing proved oil and gas property costs. Under this method, the quarterly provision for DD&A will be 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. As a result of the change in accounting principle, we recognized a cumulative transition adjustment of $4,031, which will be a charge against our 2003 net income.

NOTE 5 — INCOME TAXES:

An analysis of our deferred taxes follows:

	As of December 31,	
	2002	2001
Net operating loss carryforward	$18,010	$9,795
Statutory depletion carryforward	4,917	4,787
Contribution carryforward	276	158
Capital loss carryforward	64	43
Alternative minimum tax credit carryforward	812	812
Temporary differences:		
Oil and gas properties — full cost	(84,853)	(48,617)
Hedges	3,071	(4,214)
Other	(69)	1,838
Valuation allowance	(276)	(158)
	($58,048)	($35,556)

For tax reporting purposes, operating loss carryforwards totaled approximately $51,457 at December 31, 2002. If not utilized, such carryforwards would begin expiring in 2009 and would completely expire by the year 2021. In addition, we had approximately $14,671 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, 2002, a deferred tax asset of $1,556 was included in other current assets.

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

	Year Ended December 31,		
	2002	2001	2000
Income tax expense (benefit) computed at the statutory federal income tax rate	35%	(35%)	35%
Non-deductible portion of merger expenses	-	2%	-
Other	-	(1%)	-
Effective income tax rate	35%	(34%)	35%

Income tax expense (benefit) allocated to accumulated other comprehensive income amounted to $6,604 and ($4,036) for 2002 and 2001, respectively.

NOTE 6 — LONG-TERM DEBT:

Long-term debt consisted of the following at:

	December 31,	
	2002	2001
8¼% Senior subordinated notes due 2011	$200,000	$200,000
8¾% Senior subordinated notes due 2007	100,000	100,000
Bank debt	131,000	126,000
Total long-term debt	$431,000	$426,000

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. There are no sinking fund requirements 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

NOTE 6 — LONG-TERM DEBT: (Continued)

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, 2002, $746 had been accrued in connection with the June 15, 2003 interest payment.

At December 31, 2002, long-term debt included $100,000 of 8¾% Senior Subordinated Notes due 2007 and there were no minimum principal payments due until maturity in 2007. At December 31, 2002, $2,601 had been accrued in connection with the March 15, 2003 interest payment. The Notes were sold at a discount for an aggregate price of $99,283. There are no sinking fund requirements on the Notes and they are redeemable at our option, in whole or in part, at 104.375% of their principal amount beginning September 15, 2002, and thereafter at prices declining annually to 100% on and after September 15, 2005. 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, 2002, we had $131,000 of borrowings outstanding under our bank credit facility and letters of credit totaling $13,084 had been issued pursuant to the facility. During December 2001, we increased our credit facility to $350,000. The amended credit facility matures on December 20, 2004. At December 31, 2002, we had a borrowing base under the amended credit facility of $300,000, with availability of an additional $155,916 of borrowings. The weighted average interest rate under the amended credit facility was approximately 2.8% at December 31, 2002. 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 $350,000 as of September 30, 2001, 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.

NOTE 7 — TRANSACTIONS WITH RELATED PARTIES:

James H. Stone and Joe R. Klutts, both directors of Stone Energy, collectively own 9% of the working interest in certain wells drilled on Section 19 on the east flank of Weeks Island Field. These interests were acquired at the same time that our predecessor company acquired its interests in Weeks Island Field. In their capacity as working interest owners, they are required to pay their proportional share of all costs and are entitled to receive their proportional share of revenues.

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, chief executive officer, and James H. Prince, chief financial officer, remain net profit interest owners. Amounts paid to these officers under the remaining net profits arrangement amounted to $934, $1,777 and $1,085 in 2002, 2001 and 2000, respectively. In addition, Michael E. Madden, our Vice President of Engineering, 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 us as an independent engineering consultant. The amount paid to Michael E. Madden during 2002 under the overriding royalty arrangement totaled $61. Mr. Madden was promoted to Vice President of Engineering in March of 2002.

In June 2000, we purchased property that adjoins our Lafayette office from StoneWall Associates for an independently appraised value of approximately $540. Two of our directors, James H. Stone and Joe R. Klutts, are partners of StoneWall Associates.

Joe R. Klutts, one of our directors, received $17, $56 and $41 during 2002, 2001 and 2000, respectively, in consulting fees after retiring, February 1, 2000, as an employee of Stone.

Laborde Marine Lifts, Inc., of which John P. Laborde, one of our directors, is Chairman, provided services to us during 2000. The value of these services was approximately $75. Additionally, Laborde Marine LLC, in which Mr. Laborde's son has an interest, provided services to us during 2002 and 2001 in the amount of $1,717 and $255, respectively. John P. Laborde has no interest in Laborde Marine LLC.

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, 2001 and 2000. The value of these services totaled approximately $14, $20 and $9 during 2002, 2001 and 2000, respectively.

NOTE 8 — 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 when entered into. 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, beginning January 1, 2001, 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 non-cash derivative expenses. Any amount received or paid to terminate a contract reduces the asset or liability, respectively, associated with the contract. Changes in market value previously recognized in other comprehensive income is amortized to earnings over the remaining life of the original contract.

We adopted SFAS No. 133 effective January 1, 2001. Upon adoption of SFAS No. 133, as amended, the after-tax increase in fair value over historical cost of our oil put contracts of $1,736 was a transition adjustment that was recorded as a gain in equity through other comprehensive income.

At December 31, 2002, our gas puts were reflected as assets at a fair value of $859. Our gas put contracts are with Bank of America, N.A., J. Aron & Company and Bank of Montreal. 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. Our put contracts are considered effective hedges under SFAS No. 133 and all changes in fair value are recorded, net of taxes, in other comprehensive income.

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. Accumulated other comprehensive income on December 31, 2002 included $2,361 related to the swap contract that will be amortized during 2003.

Because over 90% of our production has historically been derived from the Gulf Coast Basin, we believe that fluctuations in NYMEX 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 NYMEX futures contracts for the three days prior to the settlement date.

The following table shows our hedging positions as of January 1, 2003:

	Natural Gas Puts		
	Volume (BBtus)	Floor	Unamortized Cost
2003	27,375	$3.00	$4,563

We entered into additional natural gas hedges during January 2003 under fixed-price swap contracts based upon deliveries in the Rocky Mountains and put contracts for Gulf Coast Basin production. The swap contracts effectively hedge 10,000 MMBtu per day at a swap price of $3.68 from April 2003 until December 2003 and 15,000 MMBtu per day at a swap price of $3.42 from January 2004 until December 2005. The put contracts effectively hedge 25,000 MMBtu per day with a floor price of $3.50 per MMBtu from March 2003 until December 2003. The put contracts' cost of approximately $516 will be charged to earnings as the contracts settle.

During 2002 and 2001, we recognized $15,968 and $2,604, respectively, of non-cash derivative expenses. The components of non-cash derivative expenses were as follows:

	Year Ended December 31,	
	2002	2001
Amortization of cost of put contracts	$13,175	$3,112
Change in fair value of swap contract	104	(339)
Amortization of other comprehensive income	2,689	(169)
	$15,968	$2,604

For the years ended December 31, 2002, 2001 and 2000, we realized net increases (decreases) in oil and gas revenue related to hedging transactions of $5,953, ($1,819) and ($47,899), respectively.

NOTE 9 — COMMON STOCK:

On February 1, 2001, our stockholders approved a proposal to amend our certificate of incorporation, in connection with the Basin merger, increasing the number of authorized shares of our common stock from 25,000,000 to 100,000,000.

NOTE 10 — COMMITMENTS AND CONTINGENCIES:

On July 29, 2002, we entered into a $28,000 work commitment for at least five wells over a two-year period on the Pinedale Anticline in the Green River Basin in Wyoming. After the initial $28,000 investment and the drilling of five wells, we will have earned a 50% working interest in the project area. As of December 31, 2002, $7,086 had been invested in two wells under the original work commitment.

We lease office facilities in New Orleans, Louisiana, Denver, Colorado and two locations in Houston, Texas under the terms of long-term, non-cancelable leases expiring on April 4, 2003, March 15, 2005 and December 31, 2004 and March 31, 2006, respectively. We also lease automobiles under the terms of non-cancelable leases expiring at various dates through 2005. The minimum net annual commitments under all leases, subleases and contracts noted above at December 31, 2002 were as follows:

2003	$947
2004	912
2005	585
2006	130
2007	-
Thereafter	-

Payments related to our lease obligations for the years ended December 31, 2002, 2001 and 2000 were approximately $889, $1,280 and $1,146, respectively. We sublease office space to third parties, and for the years ended 2002, 2001 and 2000, we recorded related receipts of $239, $285 and $181, respectively. Minimum lease rentals to be received from the sublease of office space is $239 for each of the years ended December 31, 2003, 2004 and 2005.

We are contingently liable to surety insurance companies in the aggregate amount of $40,966 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, to have a material adverse effect on our financial condition.

Goodrich Petroleum Corporation, Goodrich Petroleum Company, L.L.C. and Goodrich Petroleum Company-Lafitte, L.L.C. filed civil action number 2000-06437, in Harris County, Texas, against Stone Energy Corporation, seeking seismic data at Lafitte Field and unspecified damages. Subsequently, the same third party that had granted a data use license to Stone granted a similar license to plaintiffs at no cost and provided plaintiffs with the seismic data. We do not expect this matter to 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.

NOTE 11 — 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 $2,890 at December 31, 2002, of which $1,975 was payable to certain officers or their beneficiaries and $915 was payable to us. Total cash surrender value of the policies, net of related surrender charges at December 31, 2002, was approximately $899. Additionally, the benefits under the deferred compensation agreements vest after certain periods of employment, and at December 31, 2002, the liability for such vested benefits was approximately $808. The difference between the actuarial determined liability for retirement benefits or the vested amounts, where applicable, and the net cash surrender value has been recorded as an other long-term asset.

We have adopted a series of incentive compensation plans designed to align the interests of our directors and employees with those of our stockholders. The following is a brief description of each of the plans:

i. The Annual Incentive Compensation Program provides 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 expenses of $851, $523 and $1,722, net of amounts capitalized, for the years ended December 31, 2002, 2001 and 2000, respectively, related to incentive compensation bonuses paid under this program.

   In February 2003, our board of directors approved and adopted the Revised Annual Incentive Compensation Plan. The Plan will provide for annual cash incentive bonuses that are tied to the annual return on our common stock, to a stock performance comparison to our peers, to growth in our earnings and net asset value per share and to the achievement of certain strategic objectives as defined by our board of directors on an annual basis.

ii. The 2001 Amended and Restated Stock Option Plan provides for 3,225,000 shares of common stock to be reserved for issuance pursuant to this plan. Under this 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 five years subsequent to award. The number of shares reserved for issuance pursuant to the 2001 Amended and Restated Stock Option Plan does not include approximately 348,000 outstanding stock options assumed on February 1, 2001 in connection with the merger with Basin Exploration, Inc.

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, 2002, 2001 and 2000, Stone contributed $645, $688 and $445, respectively, to the plan.

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. However, disclosures as if we had adopted the expensed recognition provisions under SFAS No. 123 are presented below.

If the compensation expense for stock-based compensation plans had been determined consistent with the expense recognition provisions under SFAS No. 123, our 2002, 2001 and 2000 net income (loss) and basic and diluted earnings (loss) per common share would have approximated the pro forma amounts below:

	Year Ended December 31,					
	2002		2001		2000	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
Net income (loss)	$55,399	$49,986	($71,375)	($76,659)	$126,457	$121,248
Earnings (loss) per common share:						
Basic	$2.10	$1.90	($2.73)	($2.94)	$4.90	$4.70
Diluted	$2.09	$1.89	($2.73)	($2.94)	$4.80	$4.60

A summary of stock options as of December 31, 2002, 2001 and 2000 and changes during the years ended on those dates is presented below.

	Year Ended December 31,					
	2002		2001		2000	
	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....	2,058,531	$38.04	1,880,077	$34.39	1,771,668	$27.22
Granted	625,500	34.23	588,200	48.72	455,045	51.92
Expired	(103,892)	44.35	(163,861)	47.18	(13,000)	23.95
Exercised	(160,582)	24.55	(245,885)	28.81	(333,636)	20.52
Outstanding at end of year	2,419,557	$37.68	2,058,531	$38.04	1,880,077	$34.39
Options exercisable at year-end	1,082,536	32.77	963,761	27.95	808,072	24.48
Options available for future grant	353,550		910,750		957,250	
Weighted average fair value of options granted during the year....	$16.12		$23.86		$28.65	

The weighted average fair value of each option granted during the periods presented is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: (a) dividend yield of 0%, (b) expected volatility of 45.10%, 44.24% and 45.72% in the years 2002, 2001 and 2000, respectively, (c) risk-free interest rate of 3.11%, 4.88% and 6.76% in the years 2002, 2001 and 2000, respectively, and (d) expected life of six years for employee options and four years for director options.

The following table summarizes information regarding stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Options Outstanding at 12/31/02	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable at 12/31/02	Wgtd. Avg. Exercise Price
$9 – $20	157,200	1.8 years	$12.31	157,200	$12.31
20 – 30	416,250	4.3 years	23.72	399,250	23.57
30 – 40	1,058,485	8.4 years	34.98	251,340	36.38
40 – 50	190,500	7.9 years	44.85	59,300	45.62
50 – 61.93	597,122	7.0 years	56.59	215,446	60.00
	2,419,557	6.9 years	37.68	1,082,536	32.77

NOTE 12 — OIL AND GAS RESERVE INFORMATION – UNAUDITED:

Our net proved oil and gas reserves at December 31, 2002 have been estimated by independent petroleum consultants in accordance with guidelines established by the Securities and Exchange Commission ("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, 1999	35,213	385,667
Revisions of previous estimates	(3,568)	(10,499)
Extensions, discoveries and other additions	6,375	85,534
Purchase of producing properties	54	7,394
Production (1)	(4,449)	(69,572)
Proved reserves as of December 31, 2000	33,625	398,524
Revisions of previous estimates	(1,703)	(2,876)
Extensions, discoveries and other additions	2,727	52,742
Purchase of producing properties	24,765	59,849
Production (1)	(4,023)	(65,570)
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
Proved developed reserves:		
as of December 31, 2000	25,374	307,320
as of December 31, 2001	43,094	351,269
as of December 31, 2002	39,772	334,692

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

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. 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 2002 year-end product prices for all of our properties were $30.41 per barrel of oil and $4.86 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.

NOTE 12 — OIL AND GAS RESERVE INFORMATION – UNAUDITED: (Continued)

	Standardized Measure Year Ended December 31,		
	2002	2001	2000
Future cash flows	$3,713,318	$2,274,665	$4,902,297
Future production costs	(581,539)	(481,874)	(451,935)
Future development costs	(414,518)	(285,568)	(249,598)
Future income taxes	(645,160)	(212,883)	(1,392,078)
Future net cash flows	2,072,101	1,294,340	2,808,686
10% annual discount	(697,391)	(385,764)	(825,937)
Standardized measure of discounted future net cash flows	$1,374,710	$908,576	$1,982,749

	Changes in Standardized Measure Year Ended December 31,		
	2002	2001	2000
Standardized measure at beginning of year	$908,576	$1,982,749	$691,481
Sales and transfers of oil and gas produced, net of production costs	(289,830)	(333,200)	(368,243)
Changes in price, net of future production costs	862,253	(2,097,695)	1,784,727
Extensions and discoveries, net of future production and development costs	240,056	134,876	656,944
Changes in estimated future development costs, net of development costs incurred during the period	(43,607)	61,994	30,608
Revisions of quantity estimates	22,146	(19,982)	(162,462)
Accretion of discount	103,880	294,179	83,064
Net change in income taxes	(279,829)	828,820	(819,893)
Purchases of reserves in-place	3,374	314,394	48,752
Sales of reserves in-place	(1,403)	-	-
Changes in production rates due to timing and other	(150,906)	(257,559)	37,771
Standardized measure at end of year	$1,374,710	$908,576	$1,982,749

NOTE 13 — SUMMARIZED QUARTERLY FINANCIAL INFORMATION – UNAUDITED:

	Revenue	Expenses	Net Income (Loss)	Basic Earnings (Loss) Per Share	Diluted Earnings (Loss) Per Share
2002					
First Quarter	$80,530	$74,274	$6,256	$0.24	$0.24
Second Quarter	100,438	84,454	15,984	0.61	0.60
Third Quarter	94,523	80,830	13,693	0.52	0.52
Fourth Quarter	102,004	82,538	19,466	0.74	0.74
	$377,495	$322,096	$55,399	$2.10	$2.09
2001					
First Quarter	$142,994	$103,735	$39,259	$1.51	$1.49
Second Quarter	106,011	76,943	29,068	1.11	1.10
Third Quarter	82,366	227,434	(145,068)	(5.54)	(5.54)
Fourth Quarter	64,128	58,762	5,366	0.20	0.20
	$395,499	$466,874	($71,375)	($2.73)	($2.73)

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 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.

Finding costs. Costs associated with acquiring and developing proved oil and gas reserves which are capitalized pursuant to generally accepted accounting principles, excluding any capitalized general and administrative expenses.

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 Overnight Rate of interest.

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.

GLOSSARY OF CERTAIN INDUSTRY TERMS: (Continued)

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.

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.

Pooling-of-Interests. An accounting method for business combinations in which the financial statements and results of operations are prepared as if the companies had been combined at the beginning of the earliest period shown. In addition, the assets and liabilities of the combining companies are carried forward to the combined entity at book value.

Present value. When used with respect to oil and gas reserves, present value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

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 developed acreage where the subject reserves cannot be recovered without drilling additional wells.

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

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Annual Meeting

The Company's annual meeting of stockholders will be held at 10:00 a.m. on May 21, 2003 in the Denechaud Room of the Le Pavillon Hotel, Poydras at Baronne, 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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