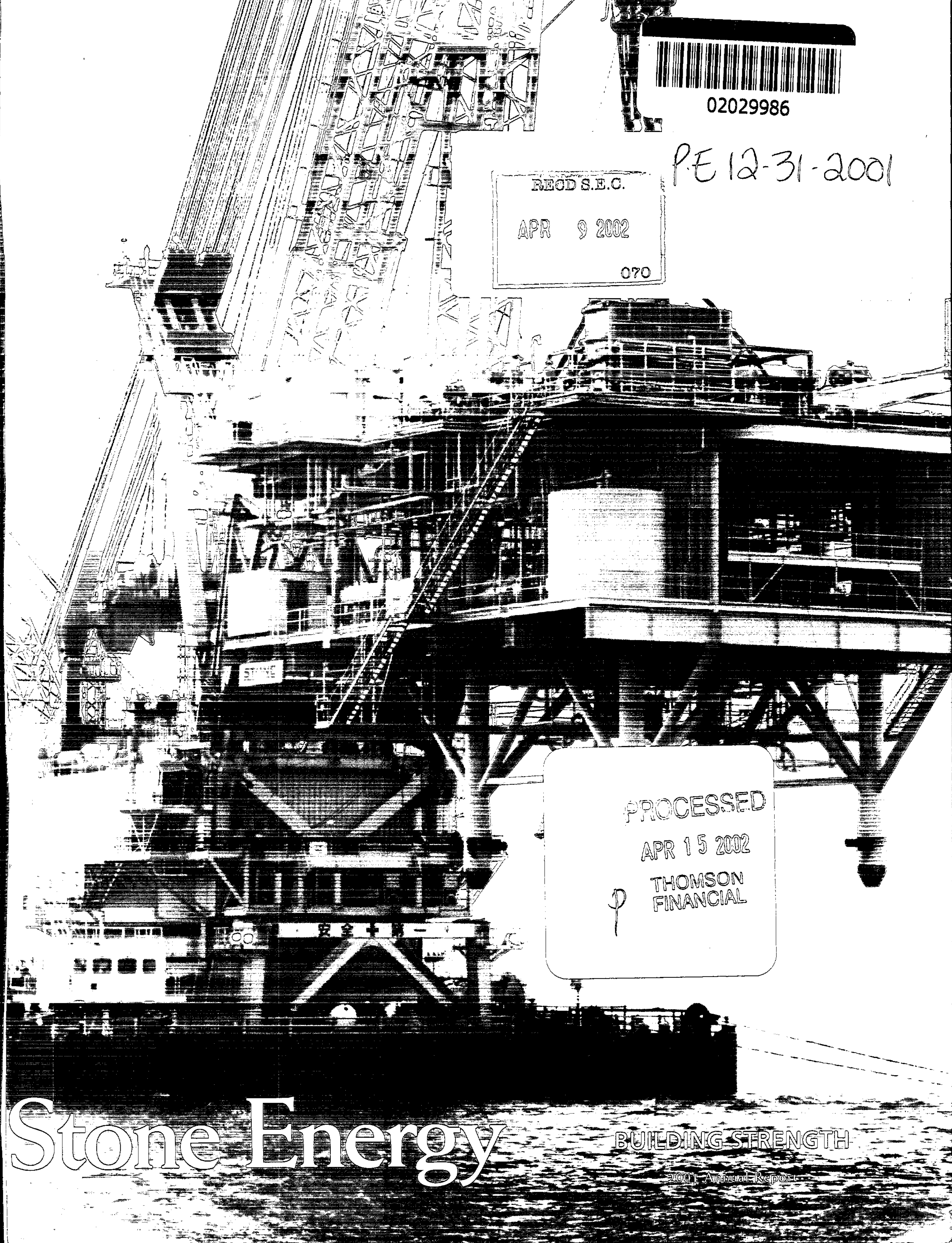


Stone Energy

BUILDING STRENGTH

2001 Annual Report

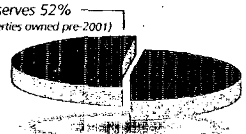
BUILDING STRENGTH

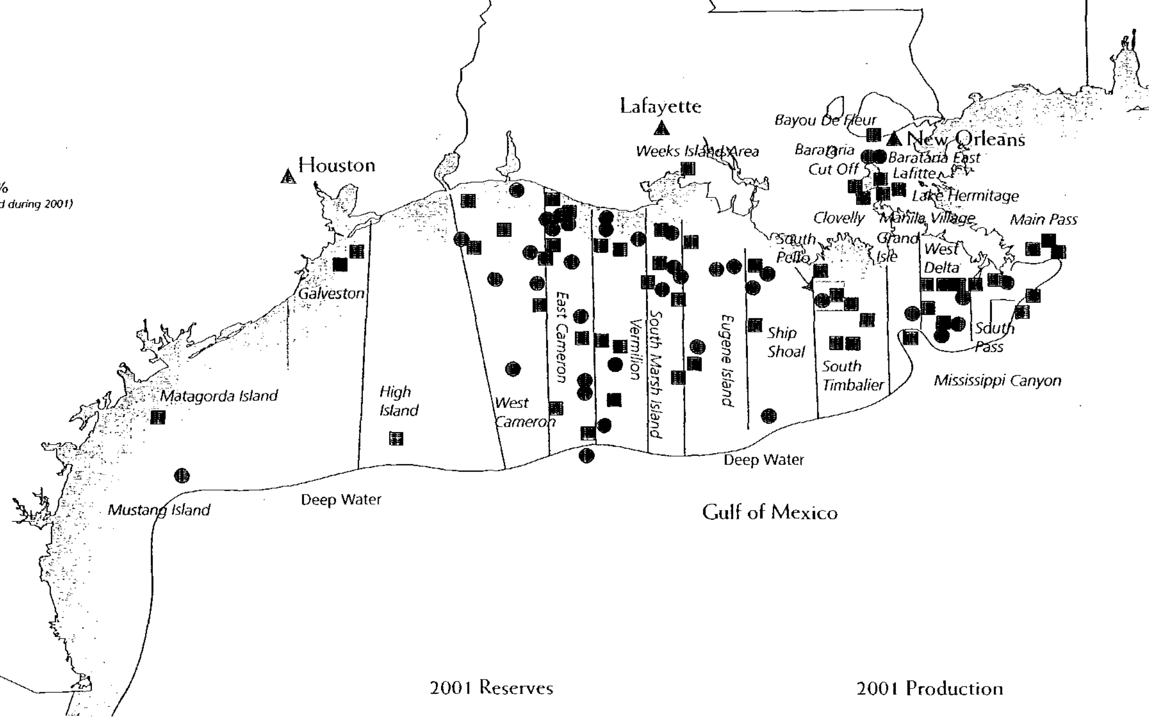
The mission of Stone Energy Corporation is to provide our shareholders with superior rates of return through consistently profitable operations and prudent management of the risks inherent to the oil and gas industry while fostering a corporate character of business integrity, creativity, technical excellence, employee involvement, environmental awareness and community service.

STONE ENERGY

The Gulf Coast Basin continues to be our core area of focus. Our merger and acquisition transactions during 2001 more than doubled our Gulf Coast producing properties and prospect inventory and provided us with a second geographic operating area—the Rocky Mountains.

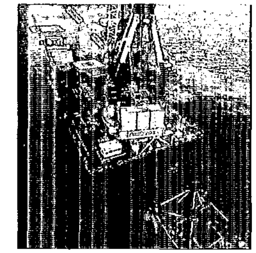
2001 Reserve Components





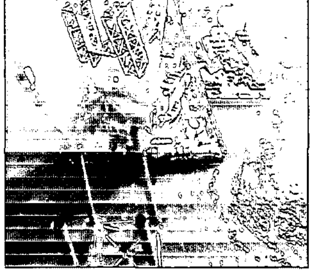
2001 Reserves

2001 Production

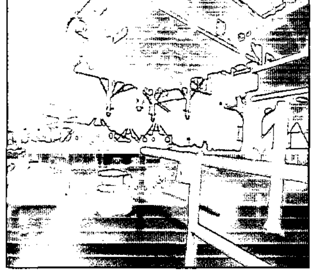


ON THE COVER

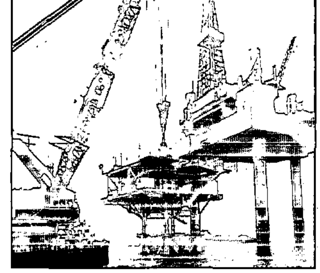
Installation of production platform at South Pass Block 38. This $10 million facility was installed in November 2001 and production commenced from the field in the first quarter of 2002. Above and to the right is a chronological sequence of the platform's installation.



Noon 11/20/01–Platform foundation in place.



7:05 a.m. 11/21/01–Preparing to set platform.



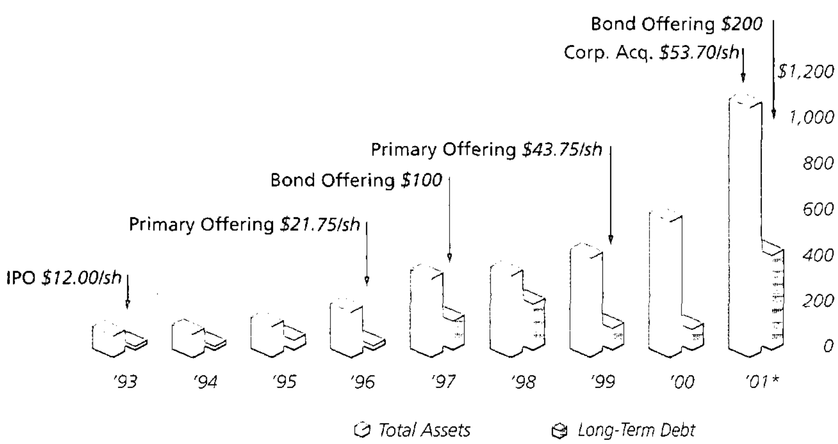
2:30 p.m. 11/21/01–Installation completed.

FIVE-YEAR OPERATIONAL HIGHLIGHTS[1]

	Year Ended December 31,				
	2001	2000	1999	1998	1997
Production					
Oil (MBbls)	**4,023**	4,449	4,324	3,601	2,109
Gas (MMcf)	**68,236**	72,239	65,513	50,897	19,692
Oil and Gas (MMcfe)	**92,374**	98,933	91,457	72,503	32,346
Average Sales Prices [2]					
Oil (per Bbl)	**$ 25.62**	$ 26.66	$ 16.19	$ 13.40	$ 19.41
Gas (per Mcf)	**4.29**	3.64	2.27	2.26	2.67
Oil and Gas (per Mcfe)	**4.28**	3.86	2.39	2.25	2.89
Estimated Proved Reserves					
Oil (MBbls)	**55,391**	33,625	35,213	27,143	25,917
Gas (MMcf)	**442,669**	398,524	385,667	370,772	278,773
Oil and Gas (MMcfe)	**775,015**	600,274	596,945	533,630	434,275
Present Value of Estimated Future					
Pre-Tax Net Cash Flows (in thousands)	**$1,038,797**	$2,941,790	$830,606	$450,583	$529,160

(1) Amounts for all periods presented reflect the 2001 merger accounted for as a pooling-of-interests.
(2) Includes the effects of hedging.

Growth in Shareholder Value
($ in millions)



*Reflects Merger & Conoco Acquisition

DEAR FELLOW Shareholders

During 2001, we overcame a series of challenges and pursued a multitude of opportunities, ending the year with real growth in assets and company strength. In a high price and high cost environment, we were able to move Stone to a new level of reserve and production magnitude by adhering to the strategy that has been our hallmark throughout our public life: to grow reserves, production and cash flow principally from Gulf Coast Basin property acquisitions and exploitation. Over the course of the year, we achieved remarkable results in each of these areas, compared to 2000's pre-merger numbers:

- Proved reserves increased 94%
- Average daily production jumped 39%
- Cash flow from operations rose 44%

Our first challenge in 2001 was to integrate the properties, prospects and people gained in our February 2001 merger with Basin Exploration into the Stone culture. I am pleased to report that we were prepared and able to complete this task while maintaining our trademark focus on keeping costs low and maximizing our margins, even in the face of an escalating cost environment in our industry. While service costs climbed, high product inventories, record domestic drilling rig utilization, moderate weather and a slowing economy combined to create our next challenge, a dramatic and unprecedented fall in commodity prices.

Our proved reserves at December 31, 2000 were valued at $28.01 per barrel of oil and $10.13 per Mcf of gas as compared to 2001 prices of $18.64 per barrel and $2.79 per Mcf, a 33% and 72% decline in oil and gas prices, respectively. Historically, we have used the acquisition market to grow our inventory of opportunities during periods of declining commodity prices as the cost to acquire properties generally moves in relation to the direction of oil and gas prices. Having positioned the Company through our balance sheet to acquire a package of core properties, we dedicated substantial internal resources to identifying, negotiating and financing an acquisition of properties that fit our strategic profile.

Through the hard work and dedication of our employees, we were able to close the Conoco Gulf of Mexico properties acquisition on December 31, 2001, just three short months from the time we announced our intention. These eight properties have produced over 3.6 Tcf equivalent of natural gas since their discovery and we are confident that these core properties will be a source of future growth in reserves, production, cash flow and ultimately shareholder value.

The merger and the Conoco property acquisition represent the two largest transactions in our history, totaling almost $750 million in value. To put the magnitude of these achievements in perspective, our total assets at the end of 2000 were only $602 million. The merger was financed primarily with our stock, which at the time was near its highest point ever, allowing the merger to be accretive to our stockholders. The Conoco transaction was funded with borrowings under our recently expanded credit facility and proceeds from the issuance of $200 million 8¼%, 10-year Senior Subordinated Notes. When combined, these transactions increased your ownership of proved reserves per share by 37% during 2001.

Our ability to access the credit markets to complete the Conoco deal was made possible by our disciplined efforts over the last several years to finance our capital expenditures almost entirely out of cash flow, instead of relying on bank borrowings. By maintaining a strong and flexible balance sheet, we were perfectly positioned to quickly react when a premier opportunity such as this arose.

Last year's transactions reaffirmed our commitment to concentrating our expertise on the Gulf Coast Basin. At December 31, 2001, our Gulf Coast Basin properties represented 94% of our total reserves and generated 96% of our 2001 production. The high production rates associated with Gulf Coast Basin reservoirs provides us with both opportunity and challenge. Our opportunity comes from rapid return of investment and high cash flow, and our constant challenge is to more than replace produced reserves with new volumes. During 2001 we produced just over 92 Bcfe, almost a quarter of our year-end pre-merger 2000 reserves. Based on this decline rate our reserves would deplete in about four years if no new reserves were discovered or acquired. However, through our 2001 drilling program and our acquisitions, we achieved a 518% reserve replacement ratio as we added more than 464 Bcfe of proved reserves. This marks our highest reserve replacement ratio since 1996 and the eighth consecutive year that we have more than replaced annual production with new reserves.

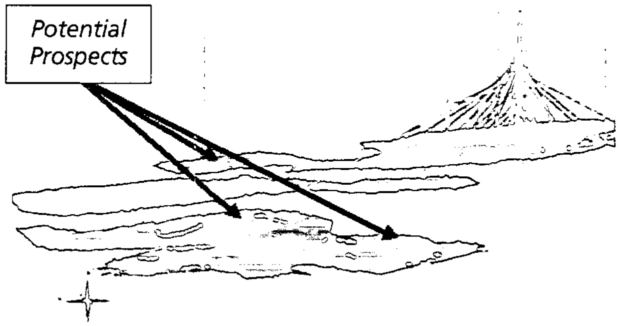
During 2001 we witnessed a soaring demand for drilling rigs and related services that, in turn, increased drilling and operating costs and greatly reduced the supply of experienced service company personnel. We, like most of our peers in the industry, endured costly operating inefficiencies and drilling delays as a result of the noticeable absence in experienced personnel. The combination of these factors and our exploratory drilling results contributed to the high overall cost of the reserves added during 2001 of $2.05 per Mcfe.

We have set our 2002 capital expenditure budget at approximately $200 million with which we expect to drill about 50 gross wells. Much lower industry costs during 2002 and a drilling program that includes many newly acquired opportunities should serve to bring our finding and development costs back down to historical averages. We plan to use cash flow in excess of our capital expenditure needs to pay down a portion of the debt we assumed during 2001. Even though our current credit statistics are in line with our peers in the industry, we will continuously strive to improve our balance sheet, strengthening our Company in the short term and, in the longer term, preparing for future growth opportunities.

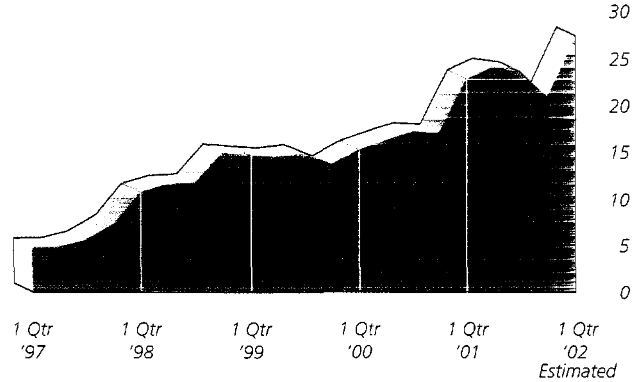
During 2001, we rebuilt our prospect inventory, the pool of ideas and opportunities from which we grow the Company. We also diversified our proved reserve base in terms of product, property and geographic concentration. Most importantly, in a year of doubling reserves, producing properties and exploratory prospects, we maintained control over our asset base. At the end of 2001, we controlled the daily operations of 82% of our reserves with an average working interest of 60% and an average net revenue interest of 41%. This achievement ensures that we will continue to control the value extraction process from our property base.

In closing, I'd like to thank all of our shareholders for their continuing trust and support of our Company. Our hard work at building Stone Energy has earned us a place among Fortune's 100 Fastest Growing Companies (No. 57). This achievement can only be attributed to the outstanding efforts made daily by every member of the Stone family. With the talent, expertise and dedication of our employees and directors, I am confident that our future achievements will prevail over the challenges that lay ahead.

D. Peter Canty
President and Chief Executive Officer



Quarterly Production Growth
(Bcfe/Qtr.)



Technology helps to identify future sources of production growth

BUILDING STRENGTH: VALIDATION OF OUR STRATEGY

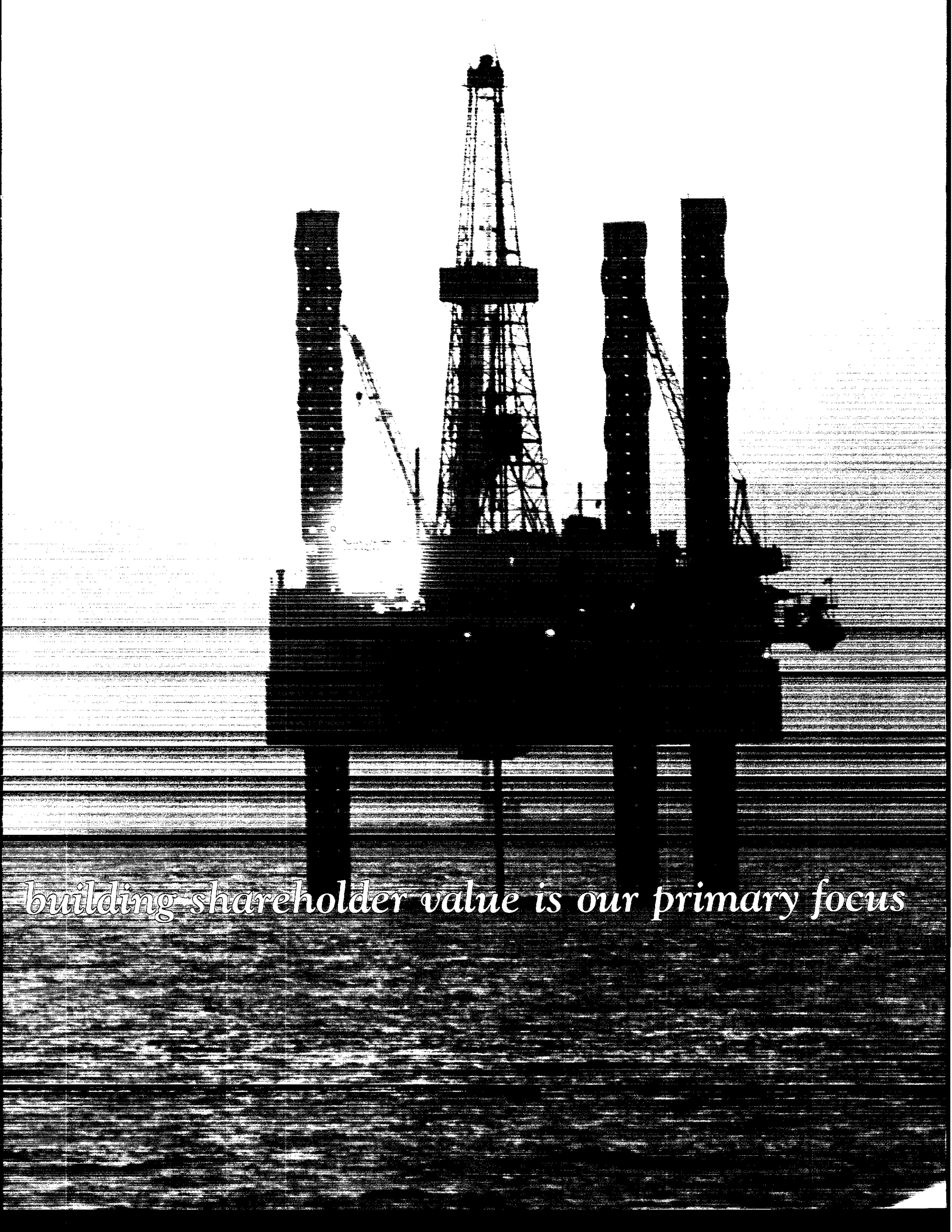
The purpose of a strategy is to map out a pathway to a specific objective. In Stone's case, our objective is two-fold—to build a superior E&P company from a solid technical and ethical foundation and to return significant value to our shareholders. Our strategy, in place since 1990, has been to grow reserves, production and cash flow through the acquisition of properties for the purpose of exploitation of untapped reserve potential. Through the merger with Basin, we expanded our producing property base to include the Rocky Mountains. Our primary area of interest remains the Gulf Coast Basin where 94% of our proved reserves and 96% of our current production are located.

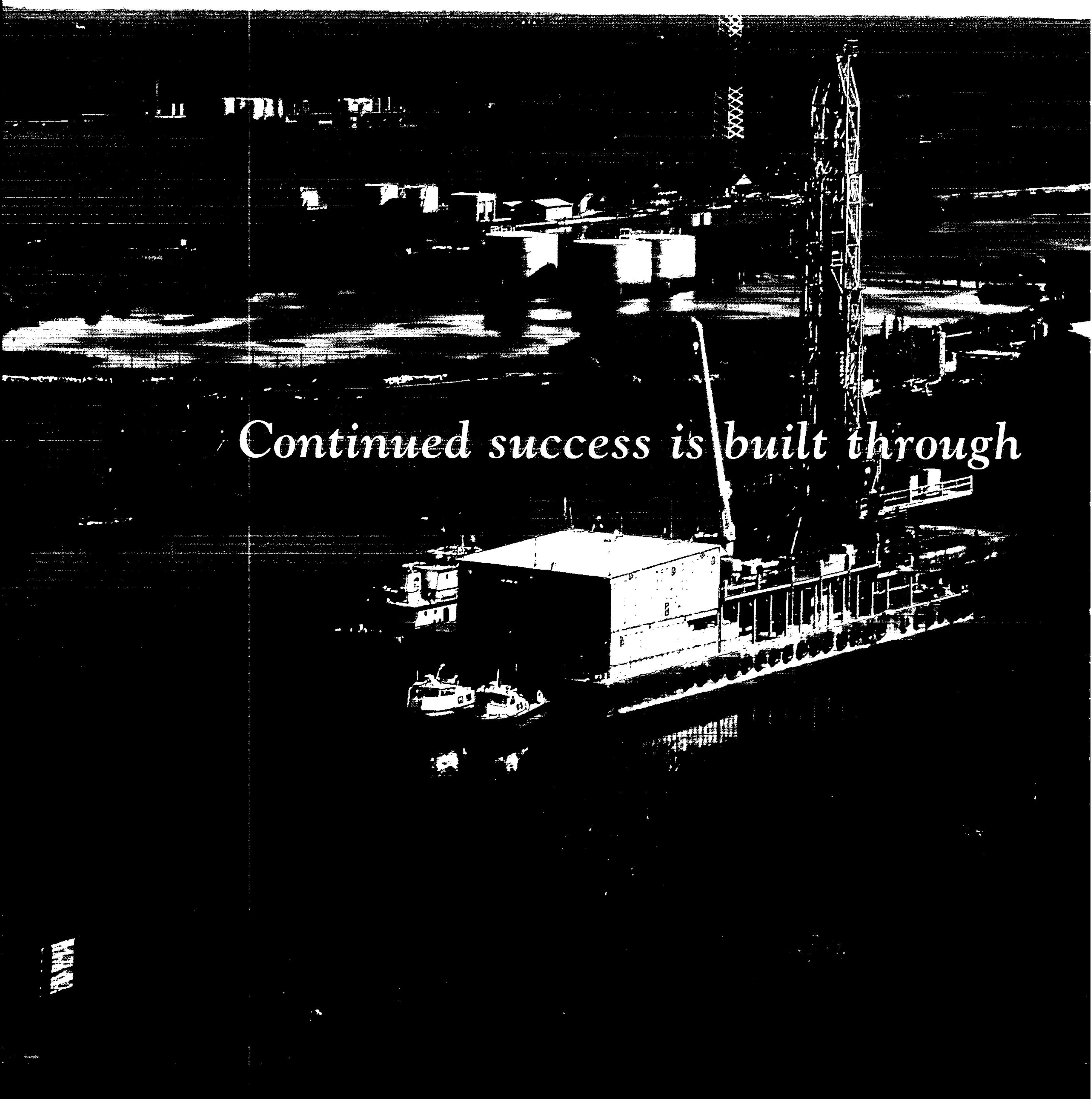
The ideal Stone acquisition target has specific common characteristics that we seek out. It has an established production history from which we can look forward by looking back, existing infrastructure and a low production rate at the time of purchase. The typical Stone property has multiple productive sands and identified opportunities for reserve and production growth, principally through the drilling of new wells. The Company strives to balance adding reserves through the purchases of properties with adding reserves through the exploitation of untapped reserves on those properties. Finally, we seek out the opportunity to operate the property, allowing us to better control the timing, selection, sequence and cost of field rejuvenation activities. This last point is vital to our role and identity as a low-cost producer.

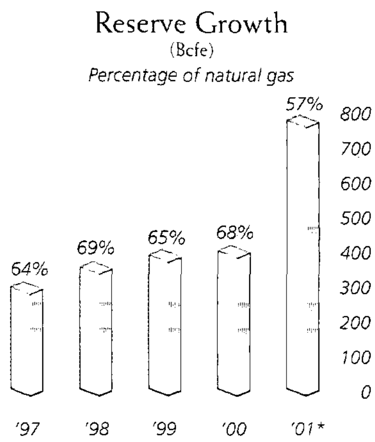
Our strategy has seen the Company safely through unparalleled volatility in the commodities market in recent years. It has provided us with the flexibility to respond appropriately to market conditions without adversely impacting our balance sheet. A low price environment affords us acquisition opportunities when sellers are divesting properties with declining production and cash flows and impending abandonment obligations. Conversely, a high price environment dictates that we curtail acquisition activities and add reserves through the drilling of our own prospect inventory across our property base. Our operations are streamlined to maximize cost efficiencies and productivity and by teaming people of multiple technical talents on every project, we achieve the larger goal of enterprise growth.

At the end of the day,

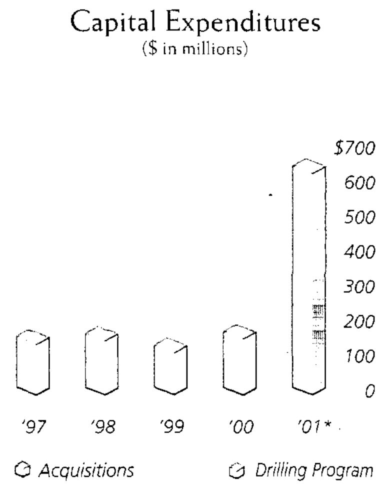
We recognize that oil and gas price volatility is a challenge for all energy companies. We believe that by using our strategy and the talents of our technically superior oil and gas finders as a blueprint for building the company, we can differentiate ourselves from our competition and create value for our shareholders. Over time, this has set our stock price performance apart from companies whose stock trades in step with oil and gas prices. An investment of $100 in our stock at our initial offering price would have been worth $329 as of December 31, 2001. This represents a compounded annual growth rate of roughly 14%. The same investment in the S&P 500 would have generated a return of only 11% over the same period of time.


building shareholder value is our primary focus


Continued success is built through



*Reflects Merger & Conoco Property Acquisition



*Reflects Merger & Conoco Property Acquisition

EXECUTING OUR STRATEGY THROUGH MERGER AND ACQUISITION

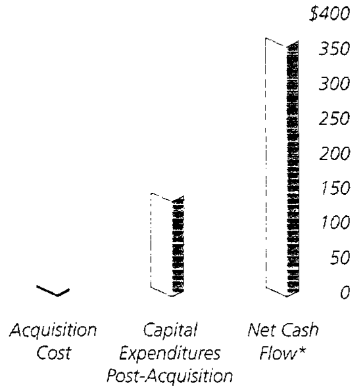
Acquisition through merger. As mentioned in the letter, we had a busy year regarding transactions that, in effect, more than doubled our size. The acquisition through merger with Basin Exploration closed on February 1, 2001 with the approval of shareholders from both companies. The stock-for-stock pooling of interests merger was the largest transaction in our history. By utilizing our stock as currency, we partially insulated the economics of the transaction from commodity price fluctuations. The acquired property base met nearly all of our strategic criteria, and provided the added benefit of an entry for Stone into the Rocky Mountain region at an exposure level that we were comfortable with. With this one acquisition through merger, we increased our Gulf Coast Basin producing properties by more than 50%, our unexplored primary term lease block position from five to more than 35 and added producing properties in seven different basins in the Rocky Mountains.

a disciplined, proven strategy

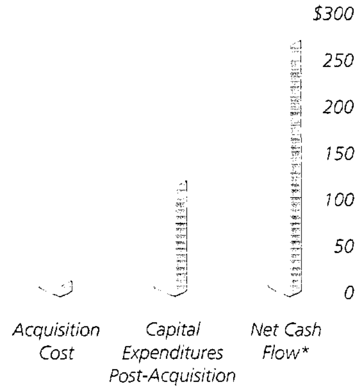
Targeting hidden value in the Conoco properties. Late in the fourth quarter of the year, we acquired eight core properties and various strategic gathering facilities and pipelines from Conoco for approximately $300 million. The purchase of properties was financed through a combination of borrowings under our recently expanded credit facility and the issuance of $200 million in Senior Subordinated Notes. The package of core properties has produced over 3.6 trillion cubic feet of gas equivalent, and was assembled as an exit strategy from the Gulf of Mexico shelf by the seller. The eight properties are located offshore on federal leases in the Gulf of Mexico and all fit the Stone strategy—mature production history with established infrastructure, multiple productive reservoirs, and operatorship on the majority of proved reserves. The properties provide an immediate impact to our operations with an approximate 37% increase in proved reserves and a 22% increase in daily production. More importantly, we believe that additional value will be realized in the future from material reserve and production growth that will come from undrilled or bypassed potential that we have already identified. Our investment in additional seismic data this year will benefit the intense technical review that each of these properties is currently undergoing. Further underscoring the strategic value of this acquisition is the significant existing infrastructure from which many of these identified opportunities can be drilled, thus reducing both future development costs and the time required to place a well on production. The transaction closed on December 31, 2001 and is accretive to our net income, cash flow and proved reserves per share.

Through our merger and acquisition activity in 2001, we added over 400 Bcfe of proved reserves, essentially doubling our premerger reserve base of 400 Bcfe at year-end 2000. The properties we acquired during 2001 are responsible for approximately 50% of our current average daily production rate. Most importantly, these acquisitions added 133 independent exploratory opportunities to our year-end 2000 prospect inventory. Ultimately, these identified opportunities will serve as a vehicle for future reserve and production growth when high commodity prices and acquisition economics dictate that organic growth through drilling is more profitable than external growth through acquisitions.

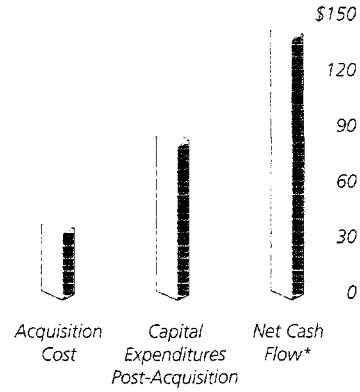
South Pelto Block 23 Field
($ in millions)



Eugene Island Block 243 Field
($ in millions)



Vermilion Block 255 Field
($ in millions)



Revenues less operating costs from acquisition through 2001 plus estimated discounted future net cash flow from proved reserves at December 31, 2001 (priced at $18.64 per barrel and $2.79 per Mcf).

THE STONE STRATEGY IN ACTION

Throughout our history, we have consistently demonstrated the ability to profitably acquire properties thought to be depleted or in a late-stage of decline, and through detailed field studies and the drill bit, substantially grow reserves and production. South Pelto Block 23, Eugene Island Block 243, Vermilion Block 255 and, most recently, South Pass Block 38 are all prime examples of our strategy in action.

SOUTH PELTO BLOCK 23

Stone acquired this Gulf Coast Basin property in 1990, when the field had essentially no production and was thought to be completely depleted. Since then, we have produced 4.7 million barrels of oil and 54.8 Bcf of gas net to Stone.

EUGENE ISLAND BLOCK 243

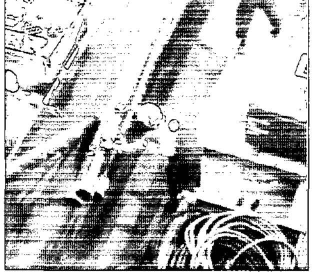
Eugene Island Block 243 was acquired in 1994 for $10.6 million—the Company's largest acquisition at that time. At the time of purchase, production from this once prolific property had declined to just four million cubic feet of gas per day. Since acquisition, we have generated net cumulative production of 1.6 million barrels of oil and 48.3 Bcf of gas.

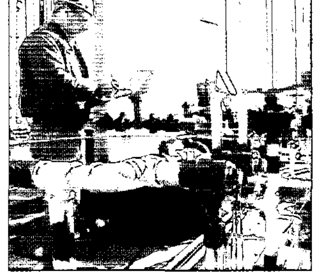
VERMILION BLOCK 255

Vermilion Block 255 became the Company's largest acquisition when we purchased it for $34.5 million in 1997. Stone consolidated field operations upon acquisition and drilled 13 consecutive successful wells over the next four years, including our five-well Indigo drilling project during 2000 and 2001. Since acquiring the field, we have produced 1.6 million barrels of oil and 17.9 Bcf of gas.

SOUTH PASS BLOCK 38

Acquired through the merger in 2001, South Pass Block 38 was the first field we turned our attention to upon closing the deal. During 2001, we invested $36.7 million to complete a four-well drilling program. The four new wells logged 1,128 feet of gas productive interval in 17 field pay sands. In November, we installed a four-pile production platform and during the first quarter of 2002 initiated production.





OPPORTUNITY KNOCKING—THE CONOCO ACQUISITION

On December 31, 2001, we closed the Conoco Gulf of Mexico property acquisition. We intend to apply our time-proven, successful strategy to revitalize these assets in order to produce from bypassed or undiscovered reservoirs. We believe that large accumulations of undiscovered reserves in the Gulf of Mexico are likely to be located near areas that have produced significant reserves in the past. Since their discovery, these properties have produced in excess of 3.6 Tcfe, a clear indication of the tremendous ongoing potential that they possess. If we can extract as little as 10% of these properties' aggregate production to date, the 360+ Bcfe yield will total more than our net production since 1993, the year Stone Energy went public.

We have allocated $35 million of our 2002 capital expenditures budget to explore and further develop these properties. During 2002, we plan to drill 10 wells and perform multiple workover and recompletion operations on these fields to begin the process of growing reserves and cash flow and building shareholder value. Our goal is to replicate our historical success with individual property acquisitions on this large package of properties. We are confident that this acquisition and the ideas and implementations that flow from the purchase will serve the Company and its shareholders very well for many years to come.

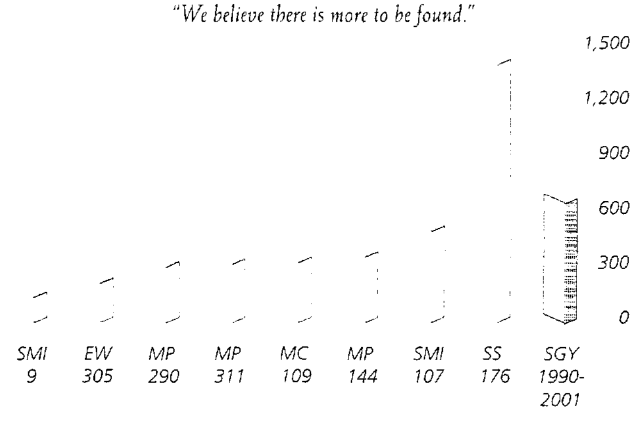
Stone Acquisition Criteria

Conoco Acquisition Properties	Significant Production History	Low Current Production	Existing Infrastructure	Multiple Productive Horizons	Identified Opportunities	Operatorship
Ewing Bank 305 Field	✓		✓	✓	✓	✓
Mississippi Canyon 109 Field	✓		✓	✓	✓	
Main Pass 144 Field	✓		✓	✓	✓	
Main Pass 290 Field	✓	✓	✓	✓	✓	✓
Main Pass 311 Field	✓		✓	✓	✓	
South Marsh Island 9 Field	✓		✓	✓	✓	
South Marsh Island 107 Field	✓	✓	✓	✓		✓
Ship Shoal 176 Field	✓	✓	✓	✓	✓	✓

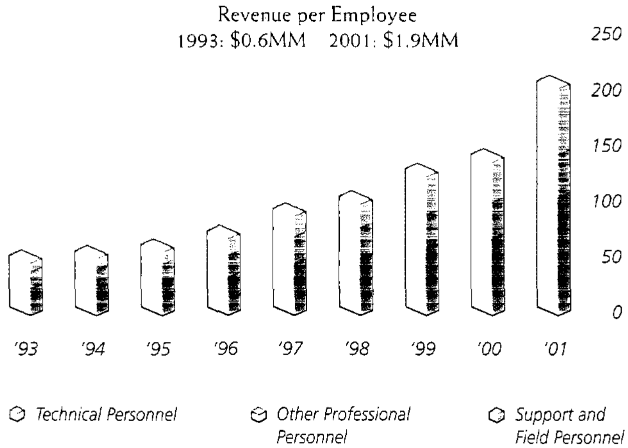
Cumulative Gross Production
(Bcfe)

Inception Through 2001

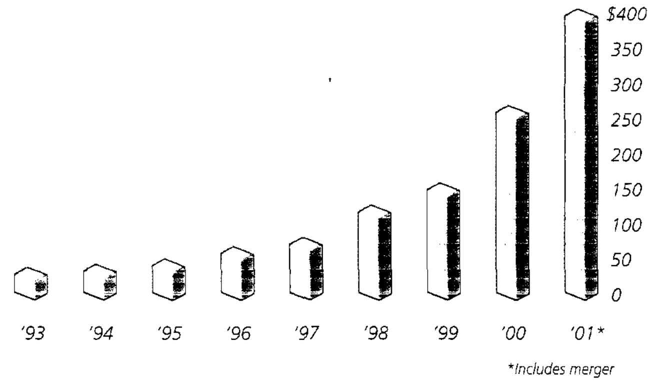
"We believe there is more to be found."



Talent and Personnel Growth
(Number of employees)



Revenue Growth
($ in millions)



THE ACTIVITY IN OUR FIELDS

Evaluation. We are collectively focused on two related goals—the better understanding of our properties to unlock potential in the form of drilling opportunities and the execution in the recovery of that value through investments that add to our reserves. To accomplish this we have structured our organization and created work protocols to emphasize creative thinking, team participation and enterprise-wide ownership of our successes and our failures. Our "Idea Generators," are highly experienced geoscientists, reservoir engineers, and other experts, most of whom specialize in the Gulf of Mexico region. These prized intellectual assets are charged with the responsibilities of discovering reserves, determining the most efficient method of exploiting them, and getting them to market cost-effectively to turn product into cash flow.

Our multi-disciplined teams work each project together, not separated by walls or layers of management. Their workspaces are highly productive environments, filled with the technology and tools they need to do the best job possible. Accordingly, our project teams share information, effort, enthusiasm and inevitably, success. This is one attribute that we have pledged to never endanger or abandon. We are a strong and dedicated family of creative thinkers and problem-solvers who recognize the value of teamwork.

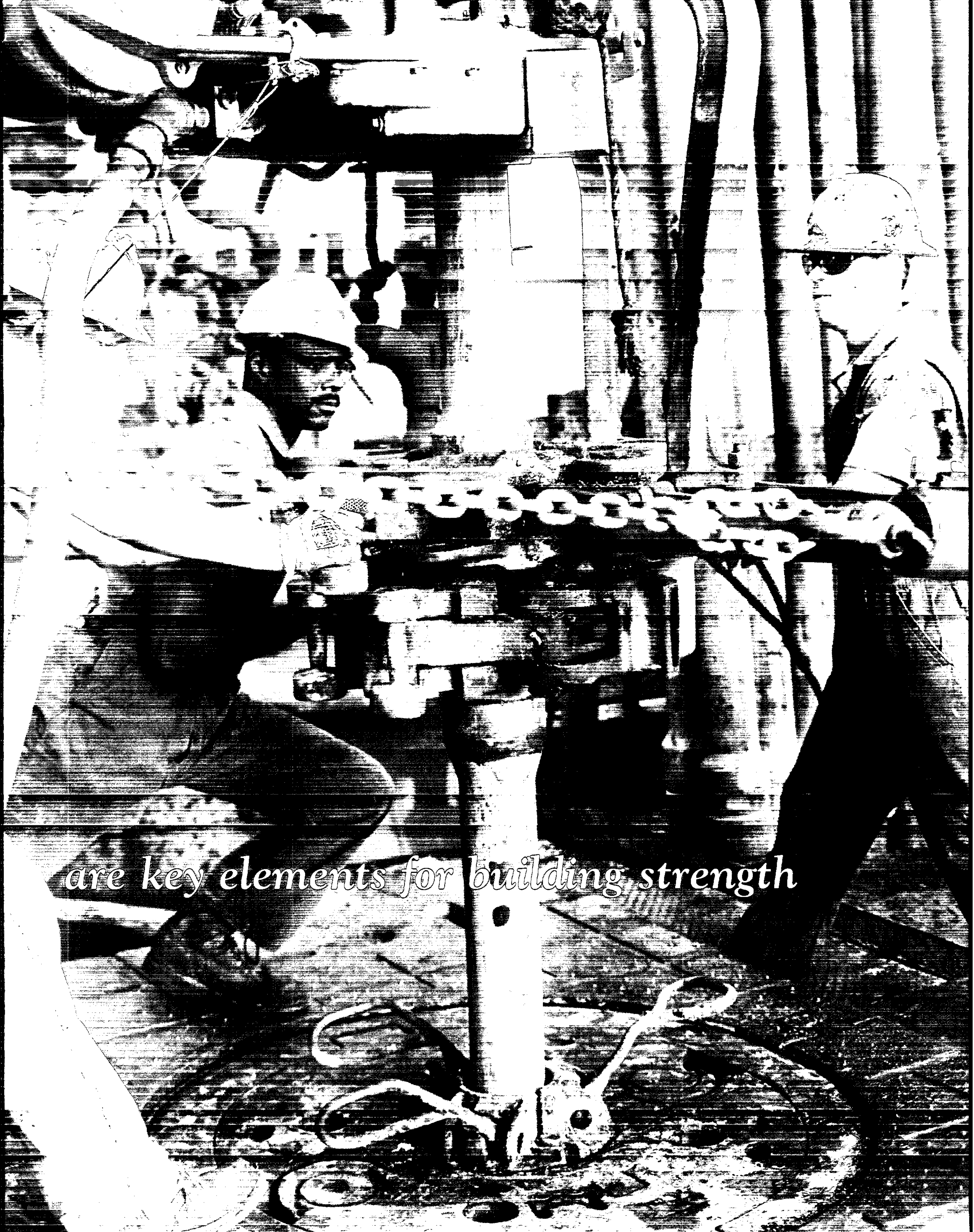
Implementation. Our 2001 drilling program was the most aggressive ever attempted by the Company. After completing our comprehensive initial evaluation of the producing properties and prospects acquired in the merger, we identified the properties requiring remedial maintenance to bring them up to Stone's operating standards. We also identified opportunities to enhance or accelerate production through workovers, recompletions and stimulation.

In 2001, we drilled 63 total wells as compared to 32 total wells drilled in 2000 and 15 total wells drilled in 1999. Our drilling success rate during 2001 was 67% with 42 discoveries and 21 dry holes.

Teamwork and dedication

Our 2001 capital expenditures, excluding the Conoco property acquisition, totaled $339.3 million, a 106% increase in capital expenditures from the previous year. Approximately 93% of 2001 capital expenditures were invested in Gulf of Mexico properties and 7% was spent on the newly acquired Rocky Mountain properties. Investments in the Gulf of Mexico included the drilling of 45 total wells, the construction and installation of six new production facilities and the acquisition of a substantial amount of seismic data. Of the wells drilled in the Gulf during 2001, 17 were drilled on properties acquired in the merger, of which 16 were successful yielding a 94% success rate. In the Rocky Mountains we drilled 18 wells during 2001 with a 50% success rate.

Looking Toward Tomorrow's Challenges. We believe that we have more than met the challenges of 2001. We successfully integrated the extended operations, properties and exploratory prospects acquired in the merger into our organization. We have accommodated the kind of exponential growth that has been known to paralyze companies less prepared. And last, we have continued to identify and pursue the most potentially profitable acquisitions in order to build the strength of our drilling portfolio, build the size of our reserves, and build our future for the benefit of all stakeholders in Stone Energy Corporation. We are proud of Stone's record of strong technical capacity and uncompromising ethics in a competitive environment. Our strategy, employees and shareholders are positioned for continued growth and success at ever-higher levels.


are key elements for building strength

BOARD OF DIRECTORS

Clockwise from left to right.
B.J. Duplantis, Robert A. Bernhard, David R. Voelker, John P. Laborde, Peter K. Barker, Richard A. Pattarozzi, D. Peter Canty, Raymond B. Gary, Joe R. Klutts, James H. Stone

Audit Committee

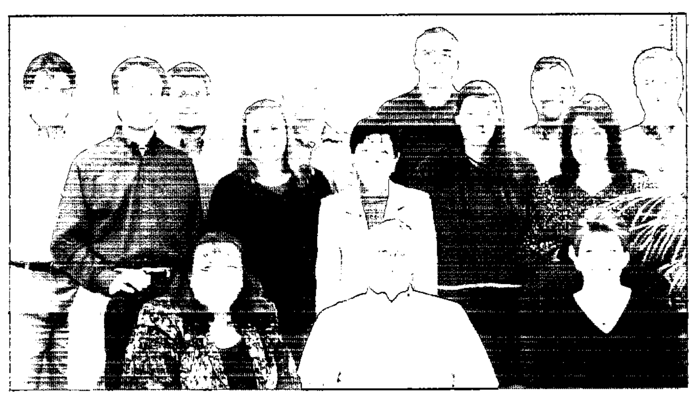
Peter K. Barker—Chairman
Robert A. Bernhard
B.J. Duplantis
Raymond B. Gary
John P. Laborde

Compensation Committee

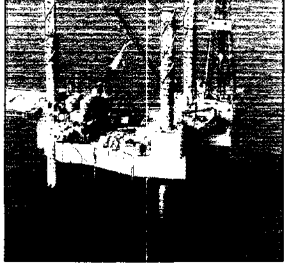
Raymond B. Gary—Chairman
B.J. Duplantis
Joe R. Klutts
Richard A. Pattarozzi
David R. Voelker

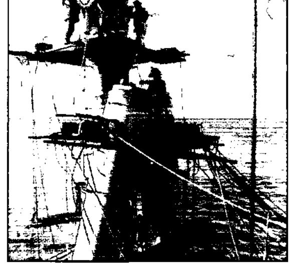
LAFAYETTE

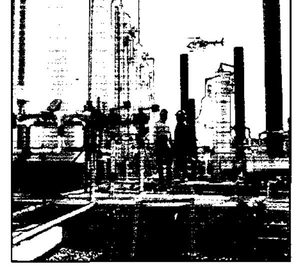
HOUSTON



DENVER





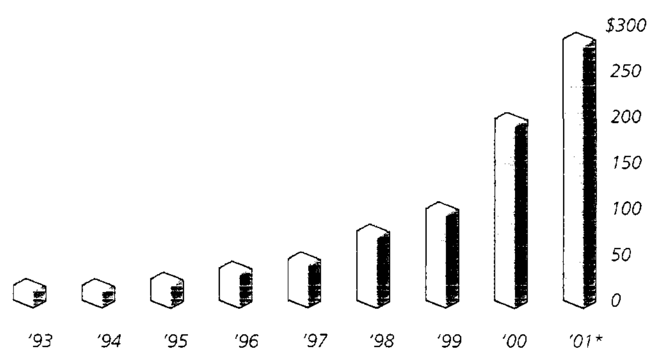


FIVE-YEAR FINANCIAL HIGHLIGHTS[1]

(amounts in thousands, except per share data)	Year Ended December 31, 2001	2000	1999	1998	1997
Total Revenues	**$398,496**	$386,166	$220,764	$165,319	$95,707
Net Income (Loss) [2]	**(71,375)**	126,457	37,066	(66,524)	13,935
Per Share [2]	**(2.73)**	4.80	1.58	(3.23)	0.71
Net Cash Flow from Operations [3]	**286,758**	300,097	154,152	110,869	62,450
Per Share [3]	**10.98**	11.40	6.58	5.39	3.16
Oil and Gas Properties, net [4]	**993,906**	747,574	587,661	492,349	437,832
Total Assets [4]	**1,101,783**	944,104	706,958	581,134	515,426
Long-Term Debt	**426,000**	148,000	134,000	289,936	143,077
Stockholders' Equity [2]	**530,025**	587,577	452,870	213,131	277,975
Weighted Average Shares Outstanding–Diluted	**26,111**	26,335	23,416	20,574	19,739

(1) Amounts for all periods presented reflect the 2001 merger accounted for as a pooling-of-interests.
(2) 2001 and 1998 results include non-cash, after-tax charges of $154.5 million and $74.3 million, respectively, attributable to ceiling test write-downs.
(3) Before working capital changes.
(4) Includes $237.7 million and $114.3 million reduction in carrying value of oil and gas properties during 2001 and 1998, respectively.

Cash Flow from Operations Growth
($ in millions)



*Includes merger

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, 2001

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. [ ]

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $858,410,004 as of March 15, 2002 (based on the last reported sale price of such stock on the New York Stock Exchange Composite Tape).

As of March 15, 2002, the registrant had outstanding 26,271,252 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 16, 2002 is incorporated by reference into Part III of this Form 10-K.

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Where specifically indicated, throughout this Form 10-K, we show combined operational and financial information to give effect to our merger with Basin Exploration, which was consummated on February 1, 2001 and was accounted for as a pooling-of-interests, as if the two companies were combined at the beginning of the earliest period presented. These combined results should be used for information purposes only as they are not necessarily indicative of the results that would have occurred if the merger had been completed at the beginning of the earliest period presented.

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. We use the terms "Basin" and "Basin Exploration" to refer to Basin Exploration, Inc. The terms "merger" and "combined company" are used to refer to the combination of Stone Energy and Basin Exploration. The term "Conoco acquisition" is used to refer to the acquisition of oil and gas properties and related assets from Conoco, Inc. in December 2001. 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

Strategy and Operational Overview

Stone Energy is a leading, Gulf Coast Basin-focused independent oil and gas company engaged in the acquisition and subsequent exploration, development, production and operation of oil and gas properties. The Gulf of Mexico is a critical supply basin for the United States, accounting for approximately 25% of the total U.S. oil and gas production in 2000. 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 oil and gas properties. Our property portfolio consists of 55 active properties and 39 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. During 2001, we grew proved reserves, production and cash flow from operations, as compared to our pre-merger 2000 results, by 94%, 39% and 44%, respectively. Approximately 94% of our estimated proved reserves at December 31, 2001 and 96% of our production during 2001 were associated with our Gulf Coast Basin properties. As of December 31, 2001, we had estimated proved reserves of 775 billion cubic feet of gas equivalent (Bcfe), 79% of which were classified as proved developed and 57% of which were natural gas. For the year ended December 31, 2001, we produced an average of 253.1 million cubic feet of gas equivalent per day (MMcfe/d), 74% of which was natural gas. During 2001, we generated cash flow from operations before working capital changes of $286.8 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 selective 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 organic 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, excluding Basin's drilling results prior to our merger; we have achieved a 72% 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 17 geologists, 16 geophysicists and 23 engineers. We also employ our extensive technical database, which includes 3-D seismic data on all of our current properties and some of the properties that we are evaluating for acquisition. After acquisition, we seek to increase cash flow from existing reserves and to 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 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.

To finance the Conoco acquisition purchase price (See Recent Events below), in December 2001, we issued $200 million principal amount of 8¼% Senior Subordinated Notes due 2011 and we borrowed approximately $100 million under our recently increased credit facility. We currently have a loan base under the amended credit facility of $250 million with availability of an additional $106.7 million in borrowings as of March 15, 2002. Stone's borrowing base under the amended credit facility is redetermined periodically based on an amount established by the bank group for Stone's oil and gas properties. In September 1997, we completed an offering of $100 million principal amount of 8¾% Senior Subordinated Notes due 2007.

Recent Events

Conoco Acquisition. 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. The purchase price of approximately $300 million was financed with net proceeds from the December 2001 offering of $200 million of 8¼% Senior Subordinated Notes due 2011 and borrowings under the bank credit facility. This acquisition was consistent with our strategy of targeting properties with characteristics fitting our core business strategy. The properties provide an immediate impact to our operations in terms of reserves, production and cash flow growth. More importantly, we believe that we will realize significant future value from these properties in the form of discoveries from undrilled or bypassed potential.

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, through pooling-of-interests, of the two companies in a tax-free, stock-for-stock transaction. In connection with the approval of the merger, stockholders of Stone Energy also approved a proposal to increase the authorized shares of Stone's common stock from 25 million to 100 million shares.

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 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, 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 and/or demand for oil and gas and thus the prices available for sales of oil and gas.

Regulation

Regulation of Production. In all areas where we conduct activities, 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 arm's-length transactions in a manner that we believe to be acceptable to the MMS under its new rule. As such, we believe that the effect, if any, of this new rule will not have 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 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.

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 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 revised the FERC pricing policy by waiving price ceilings for short-term released capacity for a two-year period, and 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 are pending judicial review. We cannot predict whether and to what extent FERC's market reforms will survive judicial review and, if so, 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 recently overturned the FERC's reporting rules as exceeding its authority under OSCLA. The FERC has indicated an appeal is likely. 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 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 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 those in 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 thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States' waters, 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 Resource Conservation and Recovery Act, as amended ("RCRA"), generally does not regulate most wastes generated by the exploration and production of oil and 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 on 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 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 15, 2002, we had 205 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 recent acquisitions from Conoco;
- 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 sale of oil and 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. As a result, estimates made by different engineers often vary from one another. 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.

We have natural gas swap contracts during 2002 and 2003 with a subsidiary of Enron Corp. Depending on fluctuations in gas prices, these contracts may create a receivable owed to us from Enron's subsidiary. Due to Enron Corp's financial difficulties, there is no assurance that we will receive full or partial payment of any amount that may become owed to us under these contracts.

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.

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 Securities and Exchange Commission (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 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 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 gas prices and other factors, many of which are beyond our control. Actual production, revenues, taxes, development expenditures and operating expenses with respect to our reserves will likely vary from the estimates used. Such variances may be material.

At December 31, 2001, approximately 21% of our estimated proved reserves were undeveloped. Undeveloped reserves, by their nature, are less certain. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our oil and gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated.

You should not assume that the present value of future net revenues 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 generally 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 and stockholders' equity. The risk that we will be required to write down the carrying value of oil and gas properties increases when oil and gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. Due to low oil and gas prices at the end of 1998, in December 1998 we recorded an after-tax write-down of $74.3 million ($114.3 million pre-tax). We also 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 either 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 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 long-term 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, development and production of oil and gas reserves. Our capital expenditures were $641.3 million during 2001, $269.1 million during 2000 and $194.5 million during 1999. We have budgeted total capital expenditures in 2002, excluding property acquisitions, capitalized salaries, general and administrative costs and interest, of approximately $200 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 operations to decrease, we may be limited in our ability to spend the capital necessary to complete our drilling program. In addition, if our borrowing base under our credit facility is redetermined 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. Gulf of Mexico reservoirs tend to experience steep declines, while declines in other regions tend to be relatively slow. During 2001, 96% of our production and 94% of our proved reserves were derived from Gulf of Mexico reservoirs. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration 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, including our merger and our recent acquisitions from Conoco, 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, which are substantially greater than those available to us.

Our strategy includes increasing our production and reserves 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, including our merger with Basin and our recent acquisitions from Conoco.

Integrating acquired businesses and properties, including those acquired in connection with our merger and our recent acquisitions from Conoco, 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 30 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 occurrence of a significant event, not fully insured or indemnified against, could materially and adversely affect our financial condition and operations.

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

Production from South Pelto Block 23 and Eugene Island Block 243 each accounted for approximately 16% of our total oil and gas production volumes during 2001. Accordingly, if the level of production from either of 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, 2001, we had $426 million in outstanding indebtedness. During December 2001, we increased our bank credit facility to $350 million. We currently have a loan base under the amended credit facility of $250 million with availability of an additional $106.7 million in borrowings as of March 15, 2002.

The terms of the agreements governing our debt impose significant restrictions on our ability and the ability of our subsidiaries 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 subsidiaries 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 operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other 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. Moreover, the borrowing base limitation on our credit facility is periodically redetermined based on an evaluation of our reserves. Upon a redetermination, 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 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, such as permits for discharges of wastewaters and other substances generated in connection with drilling operations, 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, 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, including the CERCLA, as amended, and the RCRA, as amended, 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 have a material adverse effect on our 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 effect on our operations.

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 a detrimental 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 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 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 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.

Two of our officers were granted net profits interests in some of our oil and gas properties acquired prior to 1993. The recipients of net profits interests are not required to pay capital costs incurred on the properties burdened by such interests.

We received certain fees as a result of our function as managing partner of certain partnerships. These partnerships were dissolved on December 31, 1999. All participants in the partnerships, including four of our directors, James H. Stone, Joe R. Klutts, Raymond B. Gary and Robert A. Bernhard, received overriding royalty interests in the related properties in exchange for their partnership interests. For the years ended December 31, 1999, management fees and overhead reimbursements from partnerships totaled $224,000, the majority of which was treated as a reduction of our investment in oil and gas properties.

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 shareholders 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. In December 2001, we acquired interests in eight producing properties in the Gulf of Mexico from Conoco. Our current property portfolio consists of 55 active properties and 39 primary term leases in the Gulf Coast Basin and 32 active properties in the Rocky Mountains.

As of January 1, 2002, we served as operator on 62% of our active properties, including a 69% operating percentage on our Gulf Coast Basin properties. The properties that we operate accounted for 82% of our year-end 2001 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 Gas Reserves

The following table sets forth our estimated net proved oil and gas reserves and the present value of estimated future net cash flows before taxes related to such reserves as of December 31, 2001. The proved natural gas reserves at December 31, 2001 excluded 1.3 Bcf of gas dedicated to a production payment. Also excluded are the related estimated future net cash flows and the present value of estimated future net cash flows of $3.8 million and $3.7 million, respectively.

The information in this 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, 2001 by Atwater Consultants, Ltd., Ryder Scott Company, 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 flows from the sale of oil and 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 2001 year-end product prices for all of our properties were $18.64 per barrel of oil and $2.79 per Mcf of gas.

	Proved Developed	Proved Undeveloped	Total Proved	Percent Proved Developed
Oil (MBbls)	43,094	12,297	55,391	77.8%
Gas (MMcf)	351,269	91,400	442,669	79.4%
Total oil and gas (MMcfe)	609,833	165,182	775,015	78.7%
Estimated future net cash flows before income taxes (in thousands)	$1,238,584	$268,639	$1,507,223	82.2%
Present value of estimated future net cash flows before income taxes (in thousands)	$887,811	$150,986	$1,038,797	85.5%

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. As a result, estimates of reserves made by different engineers for the same property will often vary. 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,		
	2001	2000	1999
		(In thousands)	
Acquisition costs	$328,778	$15,086	$27,316
Development costs	119,426	98,004	86,218
Exploratory costs	176,679	138,420	66,848
Subtotal	624,883	251,510	180,382
Capitalized general and administrative costs and interest, net of fees and reimbursements	16,394	17,634	14,102
Total additions to oil and gas properties (1)	$641,277	$269,144	$194,484

(1) Total additions to oil and gas properties during 1999 included non-cash additions of $20.3 million related to acquisitions made through production payments.

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, 2001.

	Gross	Net
Productive Wells:		
Oil (1):		
Gulf Coast Basin	173.00	100.80
Rocky Mountain Basin......	189.00	152.44
	362.00	253.24
Gas (2):		
Gulf Coast Basin	165.00	109.39
Rocky Mountain Basin......	36.00	18.60
	201.00	127.99
Total...............................	563.00	381.23
Developed Acres:		
Gulf Coast Basin....................	47,321.00	29,164.19
Rocky Mountain Basin	47,805.00	27,723.00
Total...............................	95,126.00	56,887.19
Undeveloped Acres (3):		
Gulf Coast Basin....................	461,572.00	330,690.29
Rocky Mountain Basin	210,567.00	127,676.75
Total...............................	672,139.00	458,367.04

(1) 11 gross wells each have dual completions.
(2) 8 gross wells each have dual completions.
(3) Leases covering approximately 4% of our undeveloped gross acreage will expire in 2002, 8% in 2003, 5% in 2004, 8% in 2005 and 2% in 2006. Leases covering the remainder of our undeveloped gross acreage (73%) are held by production.

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

	Year Ended December 31,					
	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive......................	22.00	13.84	31.00	17.82	19.00	9.86
Nonproductive	20.00	15.81	20.00	10.65	10.00	5.31
Development Wells:						
Productive......................	20.00	12.03	24.00	16.68	10.00	7.59
Nonproductive	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

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 2001.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth information regarding the names, ages (as of March 15, 2002) 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	55	President, Chief Executive Officer and Director
Andrew L. Gates, III	54	Vice President, Secretary and General Counsel
Craig L. Glassinger	54	Vice President – Resources
E. J. Louviere	53	Vice President – Land
J. Kent Pierret	46	Vice President – Controller and Chief Accounting Officer
James H. Prince	59	Vice President, Chief Financial Officer and Treasurer

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 Vice President – Resources in February 2001. From December 1995 to February 2001 he served as Vice President – Acquisitions.

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

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.

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 closing prices per share of our common stock.

	High	Low
2000		
First Quarter	$50.375	$32.250
Second Quarter	61.813	44.875
Third Quarter	60.938	47.063
Fourth Quarter	67.380	50.190
2001		
First Quarter	$63.750	$47.750
Second Quarter	57.900	41.400
Third Quarter	47.110	30.000
Fourth Quarter	40.120	31.850
2002		
First Quarter (through March 15, 2002)	$38.270	$32.400

On March 15, 2002, the last reported sales price on the New York Stock Exchange Composite Tape was $37.15 per share. As of that date, there were approximately 241 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, 2001. 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,				
	2001	2000	1999	1998	1997
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenues:					
Oil production revenue	$103,053	$118,628	$70,025	$48,262	$40,926
Gas production revenue	292,446	263,310	148,390	114,955	52,554
Other revenue	2,997	4,228	2,349	2,102	2,227
Total operating revenues	398,496	386,166	220,764	165,319	95,707
Expenses:					
Normal lease operating expenses	47,564	41,474	33,372	26,318	14,723
Major maintenance expenses	6,508	6,538	1,115	1,278	1,844
Production taxes	6,408	7,607	2,933	2,853	3,475
Depreciation, depletion and amortization	158,893	110,859	101,105	98,457	40,038
Write-down of oil and gas properties	237,741	-	-	114,341	-
Interest expense	4,895	9,395	15,186	15,017	5,768
Bad debt expense (1)	2,343	-	-	-	-
Merger expenses	25,785	1,297	-	-	-
Non-cash derivative expense	2,604	-	-	-	-
Salaries, general and administrative costs	13,004	12,725	10,764	8,636	7,509
Incentive compensation plan	523	1,722	1,510	763	833
Total expenses	506,268	191,617	165,985	267,663	74,190
Net income (loss) before income taxes	(107,772)	194,549	54,779	(102,344)	21,517
Income tax provision (benefit):					
Current	(489)	450	25	23	(471)
Deferred	(35,908)	67,642	17,688	(35,843)	8,053
Total income tax provision (benefit)	(36,397)	68,092	17,713	(35,820)	7,582
Net income (loss)	($71,375)	$126,457	$37,066	($66,524)	$13,935
Earnings and dividends per common share:					
Basic net income (loss) per common share	($2.73)	$4.90	$1.61	($3.23)	$0.72
Diluted net income (loss) per common share	($2.73)	$4.80	$1.58	($3.23)	$0.71
Cash dividends declared	-	-	-	-	-
Cash Flow Data:					
Net cash provided by operating activities (before working capital changes)	$286,758	$300,097	$154,152	$110,869	$62,450
Net cash provided by operating activities	315,617	302,082	123,010	118,014	43,606
Balance Sheet Data (at end of period):					
Working capital (deficit)	($18,097)	$53,065	$12,509	($3,340)	($1,708)
Oil and gas properties, net	993,906	747,574	587,661	492,349	437,832
Total assets	1,101,783	944,104	706,958	581,134	515,426
Long-term debt, less current portion	426,000	148,000	134,000	289,936	143,077
Stockholders' equity	530,025	587,577	452,870	213,131	277,975

(1) Relates to 100% allowance for production receivable due from Enron 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, 2001. 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 shallow waters of 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 seasonal, political and economic events we can neither control nor predict.

Oil and gas prices generally peaked at the beginning of 2001 and generally declined throughout the remainder of the year. Our realized gas-equivalent price for the fourth quarter of 2001 was 51% less than our realized gas-equivalent price in the first quarter of 2001. Historically, the cost to acquire oil and gas properties moves in relation to the prices of oil and gas. When prices began to fall in early 2001, we set out to acquire a package of properties that fit our strategic characteristics.

Over the last several years, we have financed our capital expenditures primarily with cash flow from operations. By not burdening our capital structure with a high percentage of debt, we were able to access the credit markets to quickly complete the $300 million Conoco property acquisition on December 31, 2001.

Our 2002 capital expenditures budget is currently approximately $200 million, or 36% less than 2001's capital expenditures, excluding acquisitions. The decline in estimated capital investment is due to our outlook on 2002 oil and gas prices and our intent to once again finance our capital expenditures primarily with cash flow from operations. The decline in drilling and operating costs and services should enable us to evaluate wells at a much lower cost than in 2001.

To the extent that 2002 cash flow from operations exceed our estimated 2002 capital expenditures, we plan to pay down a portion of our existing debt. In the event that cash flow from operations during 2002 is not sufficient to fund estimated 2002 capital expenditures, we believe that our bank credit facility, under which we have $106.7 million of available borrowings at March 15, 2002, 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,		
	2001	2000	1999
Production:			
Oil (MBbls)	4,023	4,449	4,324
Gas (MMcf)	68,236	72,239	65,513
Oil and gas (MMcfe)	92,374	98,933	91,457
Average sales prices: (1)			
Oil (per Bbl)	$25.62	$26.66	$16.19
Gas (per Mcf)	4.29	3.64	2.27
Oil and gas (per Mcfe)	4.28	3.86	2.39
Average costs (per Mcfe):			
Normal operating costs (2)	$0.51	$0.42	$0.36
Salaries, general and administrative costs	0.14	0.13	0.12
DD&A on oil and gas properties	1.70	1.10	1.08
Reserves at December 31:			
Oil (MBbls)	55,391	33,625	35,213
Gas (MMcf)	442,669	398,524	385,667
Oil and gas (MMcfe)	775,015	600,274	596,945
Present value of estimated future net cash flows before income taxes (in thousands)	$1,038,797	$2,941,790	$830,606
Standardized measure of discounted future net cash flows (in thousands)	$908,576	$1,982,749	$691,481

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

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 higher realized prices on a Mcfe basis, oil and gas revenues increased 4% to $395.5 million in 2001 from $381.9 million during 2000.

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

Production tax expense 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 (DD&A) expense on our 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.

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 operations but did reduce net income and stockholders' equity.

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.

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 Corp. This allowance resulted in a 2001 charge of approximately $2.3 million to bad debt expense.

Our merger with Basin was completed on February 1, 2001. In connection with the completion of the merger, we incurred expenses during 2001 totaling $25.8 million. Merger expenses incurred by Basin during 2000 totaled $1.3 million.

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. You should not assume that the present values of estimated future net cash flows represent the fair value of our estimated oil and 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 $18.64 per barrel and $2.79 per Mcf for 2001 and $27.30 per barrel and $9.97 per Mcf for 2000.

2000 Compared to 1999. For the year 2000, we reported record net income totaling $126.5 million, or $4.80 per share, compared to net income for the year ended December 31, 1999 of $37.1 million, or $1.58 per share. The favorable results in net income were due to improvements in the following components:

Production. During 2000, production volumes reached a record high totaling 98.9 Bcfe compared to 91.5 Bcfe produced during 1999. Natural gas production during 2000 increased 10% to approximately 72.2 billion cubic feet compared to 1999 gas production of 65.5 billion cubic feet, while oil production during 2000 increased to approximately 4.4 million barrels compared to 4.3 million barrels produced during 1999.

The increase in 2000 production rates, compared to 1999, was due to drilling results at several of our fields, the most significant of which were Eugene Island Block 243 and East Cameron Block 64.

Prices. Prices realized during 2000 averaged $26.66 per barrel of oil and $3.64 per Mcf of gas. This represents a 62% increase, on a Mcfe basis, over 1999 average realized prices of $16.19 per barrel of oil and $2.27 per Mcf of gas. All unit pricing amounts include the effects of hedging.

Due to increases in commodity prices throughout 2000, hedging transactions reduced the average price we received during the year for oil by $3.55 per barrel and for gas by $0.46 per Mcf, compared to net decreases of $1.72 per barrel and $0.06 per Mcf realized during 1999.

Oil and Gas Revenue. As a result of higher production rates and realized prices, oil and gas revenue increased 75% to $381.9 million, compared to 1999 oil and gas revenue of $218.4 million.

Expenses. Normal operating costs during 2000 increased to $41.5 million, compared to $33.4 million during 1999. On a unit of production basis, 2000 operating costs were $0.42 per Mcfe compared to $0.36 per Mcfe for 1999. The increase in operating costs was due primarily to industry-wide increases in the costs of oil field products and services.

During 2000, we performed significant workover operations on nine wells at three fields. As a result, major maintenance expenses for the year totaled $6.5 million compared to $1.1 million for 1999.

Due to increased 2000 onshore production volumes combined with higher oil and gas prices, production revenue from onshore properties increased 100%. As a result, production tax expense increased to $7.6 million from $2.9 million in 1999. Included in the 1999 amount was a $1 million production tax refund related to the abatement of severance taxes for certain wells under Louisiana state law.

Depreciation, depletion and amortization expense on our oil and gas properties totaled $109.2 million, or $1.10 per Mcfe, compared to $99.2 million, or $1.08 per Mcfe, for 1999. The higher DD&A rate was partially attributable to the rising costs of oil and gas exploration and development activities during 2000.

Salaries, general and administrative expenses for 2000 increased in total to $12.7 million, or $0.13 per Mcfe, from $10.8 million, or $0.12 per Mcfe, during 1999. Due to our operational and financial results and our stock price performance during the year, incentive compensation expense for 2000 increased to $1.7 million compared to $1.5 million in 1999.

Interest expense for 2000 decreased to $9.4 million, compared to $15.2 million during 1999, due primarily to the repayment of approximately $120 million of borrowings under Stone's bank credit facility in August 1999.

Reserves. At December 31, 2000, our estimated proved oil and gas reserves totaled 600.3 Bcfe, compared to December 31, 1999 reserves of 596.9 Bcfe. Estimated proved gas reserves grew to 398.5 Bcf at the end of 2000 from 385.7 Bcf at year-end 1999, while estimated proved oil reserves declined to 33.6 MMBbls at the end of 2000 from 35.2 MMBbls at the beginning of the year.

Our reserve estimates at December 31, 2000 were prepared by independent petroleum consultants in accordance with guidelines established by the SEC. Adherence to these guidelines limits our recognition of proved 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 $2.9 billion and $830.6 million at December 31, 2000 and 1999, respectively. You should not assume that the present values of estimated future net cash flows represent the fair value of our estimated proved oil and 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 $27.30 per barrel and $9.97 per Mcf for 2000 and $24.83 per barrel and $2.42 per Mcf for 1999.

Liquidity and Capital Resources

Cash Flow and Working Capital. Net cash flow from operations before working capital changes for 2001 was $286.8 million, or $10.98 per share, compared to $300.1 million, or $11.40 per share, reported for 2000. Working capital at December 31, 2001 totaled ($18.1) million. 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 2001 totaled $641.3 million and included $10.4 million of capitalized general and administrative costs, net of reimbursements, and $6.0 million of capitalized interest. These investments were financed by borrowings under our bank credit facility, net proceeds from the December 2001 bond offering, cash flows from operations and working capital.

Our 2002 capital expenditures budget is currently approximately $200 million, or 36% less than 2001's capital expenditures, excluding acquisitions. The decline in estimated capital investment is due to our outlook on 2002 oil and gas prices and our intent to once again finance our capital expenditures primarily with cash flow from operations. The decline in drilling and operating costs and services should enable us to evaluate wells at a much lower cost than in 2001.

To the extent 2002 cash flow from operations exceed our estimated 2002 capital expenditures, we plan to pay down a portion of our existing debt. In the event that cash flow from operations during 2002 is not sufficient to fund estimated 2002 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.

Bank Credit Facility. At December 31, 2001, we had $126 million of borrowings outstanding under our credit facility and letters of credit totaling $7.3 million had been issued pursuant to the facility. During December 2001, we increased our credit facility to $350 million. We currently have a loan base under the amended credit facility of $250 million with availability of an additional $106.7 million in borrowings as of March 15, 2002. Stone's borrowing base under the amended credit facility, which is redetermined periodically, is based on an amount established by the bank group for Stone's oil and gas properties.

Our credit facility provides for certain covenants, including restrictions or requirements with respect to debt to EBITDA ratio, net worth, 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."

New Accounting Standards. In July 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS No. 141 prohibits the use of the pooling-of-interest method of accounting for all business combinations initiated after June 30, 2001. SFAS No. 142 requires that goodwill not be amortized in any circumstances and also requires goodwill to be tested for impairment annually or when events or circumstances occur between annual tests indicating that goodwill for a reporting unit might be impaired. The standard establishes a new method for testing goodwill for impairment based on a fair value concept and is effective for fiscal years beginning after December 15, 2001. The adoption of SFAS Nos. 141 and 142 is not expected to have a material impact on our financial statements, because we do not have any goodwill recorded.

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 expect to adopt SFAS No. 143 on January 1, 2003. Upon adoption, we will be required to recognize cumulative transition amounts for existing asset retirement obligation liabilities, asset retirement costs and accumulated depreciation. We have not yet determined the transition amounts.

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, the accounts of our wholly owned subsidiaries and our proportionate share of certain partnerships. On December 31, 1999, these partnerships were dissolved after their assets were transferred to us. All intercompany balances and transactions that existed prior to these dissolutions have been eliminated.

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.

We amortize 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.

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. Estimates of our oil and gas reserves are prepared by our independent petroleum and geological engineers. 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.

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 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, 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.

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, 2001, we had deferred taxes of $35.6 million which was calculated based on our assumption that it is more likely than not that we will have sufficient taxable income in future years to utilize certain tax attribute carryforwards.

For a more complete discussion of our accounting policies see our Notes to Consolidated Financial Statements on page F-7.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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 flows 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 gas prices.

Our hedging policy provides that not more than one-half of our production quantities can be hedged without the consent of the Board of Directors.

Hedging. 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. During 2000, we realized a net reduction in revenue from our hedging transactions of $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. The net reduction in revenue from hedging transactions for 1999 was $11.3 million. Our contracts totaled 2,094 MBbls of oil and 44,949 BBtus of gas, which represented approximately 48% and 69%, respectively, of our oil and gas production for that year.

Our oil put contracts are with Bank of America, N.A. and our gas put contracts are with J. Aron & Co. 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.

During 2001, we recognized $3.1 million of hedge premium expenses, which represents amortization of the historical cost associated with oil and gas put contracts that settled during the year.

Fixed price swaps typically provide for monthly payments by us if NYMEX prices rise above the fixed swap price or to us if NYMEX prices fall below the fixed swap price.

Since 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 January 1, 2002:

	Puts					
	Gas			Oil		
	Volume (BBtus)	Floor	Cost (millions)	Volume (Bbls)	Floor	Cost (millions)
2002	21,900	$3.50	$5.2	1,277,500	$24.00	$3.2

	Fixed Price Gas Swaps	
	Volume (BBtus)	Price
2002	3,650	$2.15
2003	3,650	2.15

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.

At December 31, 2000, our oil put contracts were reflected as assets at a historical cost of $5 million and, in accordance with generally accepted accounting principles in effect at year-end 2000, our fixed price gas swap contracts were not reflected in the financial statements since they were costless. Our gas put contracts were purchased in January 2001 and therefore were not reflected in the December 31, 2000 balance sheet. At December 31, 2000, the fair values of our oil put contracts and fixed price gas swaps were $7.7 million and ($42.8) million, respectively.

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 swaps 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, 2001 were considered effective cash flow hedges and changes in fair value of these contracts are reflected in other comprehensive income, net of related taxes.

Our natural gas swap contracts are with a subsidiary of Enron Corp. Due to Enron's financial difficulties, there is no assurance that we will receive full or partial payment of any amounts that may become owed to us under these contracts. Accordingly, these swaps no longer qualify as effective hedges under SFAS No. 133. As a result, the changes in fair value for each period will now be recorded through earnings and amounts previously recorded in other comprehensive income will be amortized through earnings over the remaining life of the swaps. At December 31, 2001, other comprehensive income included $4.1 million related to the ineffective gas swaps that will be amortized over the remaining life of the swaps. Included in the 2001 non-cash derivative expense is a $0.2 million gain from amortization of other comprehensive income and a $0.3 million gain related to the change in fair value of the swaps.

Stone uses 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. Stone had open oil and gas put positions at December 31, 2001 with a positive fair value of $26.2 million. As of March 1, 2002, a 10% increase in the underlying price of oil would have reduced the fair value of the oil puts by approximately $2.3 million. A 10% increase in the underlying price of natural gas as of March 1, 2002, would have reduced the fair value of our gas puts by approximately $3.3 million. At December 31, 2001, we also had open natural gas swap positions with a negative fair value of $5.8 million. As of March 1, 2002, a 10% increase in the underlying price of natural gas would have increased the negative fair value of the swaps by approximately $1.9 million. The fair value of our derivative instruments was based upon quotes obtained from the counterparties to the hedge agreements.

Interest Rate Risk

At December 31, 2001, Stone had long-term debt outstanding of $426 million. Of this amount, $300 million, or 70%, bears interest at fixed rates averaging 8.4%. The remaining $126 million of debt outstanding at the end of 2001 bears interest at a floating rate. Because the majority of our long-term debt at December 31, 2001 were at fixed rates, we consider our interest rate exposure at such date to be minimal. At December 31, 2001, 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, 2001. At December 31, 2001, the fair value of the 8¾% Senior Subordinated Notes due 2007 totaled $101.7 million and the fair value of the 8¼% Senior Subordinated Notes due 2011 totaled $201.9 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

None.

PART III

For 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 16, 2002, which will be filed with the Securities and Exchange Commission 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. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. Financial Statements:

The following financial statements and the Report of Independent Public Accountants thereon are included on pages F-1 through F-22 of this Form 10-K.

Report of Independent Public Accountants

Consolidated Balance Sheet as of December 31, 2001 and 2000

Consolidated Statement of Operations for the three years in the period ended December 31, 2001

Consolidated Statement of Cash Flows for the three years in the period ended December 31, 2001

Consolidated Statement of Changes in Stockholders' Equity for the three years in the period ended December 31, 2001

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.

(b) Reports on Form 8-K

Stone filed the following report on Form 8-K during the fourth quarter of 2001:

Form 8-K filed by the Registrant on November 28, 2001 (press release dated November 26, 2001 announcing updated agreement to acquire properties from Conoco Inc.).

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act, as amended, the Registrant has duly caused this Form 10-K 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 2002.

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 Form 10-K has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ James H. Stone James H. Stone	Chairman of the Board	March 19, 2002
/s/ Joe R. Klutts Joe R. Klutts	Vice Chairman of the Board	March 19, 2002
/s/ D. Peter Canty D. Peter Canty	President, Chief Executive Officer and Director (principal executive officer)	March 19, 2002
/s/ James H. Prince James H. Prince	Vice President – Chief Financial Officer and Treasurer (principal financial officer)	March 19, 2002
/s/ J. Kent Pierret J. Kent Pierret	Vice President – Controller and Chief Accounting Officer (principal accounting officer)	March 19, 2002
/s/ Peter K. Barker Peter K. Barker	Director	March 19, 2002
/s/ Robert A. Bernhard Robert A. Bernhard	Director	March 19, 2002
/s/ B.J. Duplantis B.J. Duplantis	Director	March 19, 2002
/s/ Raymond B. Gary Raymond B. Gary	Director	March 19, 2002
/s/ John P. Laborde John P. Laborde	Director	March 19, 2002
/s/ Richard A. Pattarozzi Richard A. Pattarozzi	Director	March 19, 2002
/s/ David R. Voelker David R. Voelker	Director	March 19, 2002

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders of
Stone Energy Corporation:

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

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

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

As 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."

ARTHUR ANDERSEN LLP

New Orleans, Louisiana
February 21, 2002

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

ASSETS	December 31, 2001	December 31, 2000
Current assets:		
Cash and cash equivalents	$13,155	$78,557
Marketable securities, at market	-	300
Accounts receivable	46,987	95,722
Other current assets	1,832	2,916
Put contracts	26,207	1,847
Total current assets	88,181	179,342
Oil and gas properties—full cost method of accounting:		
Proved, net of accumulated depreciation, depletion and amortization of $1,015,455 and $620,510, respectively	880,534	691,883
Unevaluated	113,372	55,691
Building and land, net of accumulated depreciation of $598 and $465, respectively	5,352	4,914
Fixed assets, net of accumulated depreciation of $9,387 and $8,059, respectively	4,883	4,441
Other assets, net of accumulated depreciation and amortization of $1,932 and $1,499, respectively	9,461	4,681
Put contracts	-	3,152
Total assets	$1,101,783	$944,104

LIABILITIES AND STOCKHOLDERS' EQUITY	2001	2000
Current liabilities:		
Accounts payable to vendors	$69,197	$83,423
Undistributed oil and gas proceeds	23,741	32,858
Deferred taxes	5,312	-
Fair value of swap contracts	2,194	-
Other accrued liabilities	5,834	9,996
Total current liabilities	106,278	126,277
Long-term debt	426,000	148,000
Production payments	4,323	10,906
Deferred taxes	30,244	68,926
Fair value of swap contracts	3,619	-
Other long-term liabilities	1,294	2,418
Total liabilities	571,758	356,527
Common stock, $.01 par value; authorized 100,000,000 shares; issued and outstanding 26,190,270 and 25,981,000 shares, respectively	262	260
Treasury stock (39,650 shares at cost)	(2,057)	-
Additional paid-in capital	449,111	440,729
Retained earnings	75,213	146,588
Other comprehensive income	7,496	-
Total stockholders' equity	530,025	587,577
Total liabilities and stockholders' equity	$1,101,783	$944,104

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,		
	2001	2000	1999
Revenues:			
Oil and gas production	$395,499	$381,938	$218,415
Other revenue	2,997	4,228	2,349
Total revenues	398,496	386,166	220,764
Expenses:			
Normal lease operating expenses	47,564	41,474	33,372
Major maintenance expenses	6,508	6,538	1,115
Production taxes	6,408	7,607	2,933
Depreciation, depletion and amortization	158,893	110,859	101,105
Write-down of oil and gas properties	237,741	-	-
Interest	4,895	9,395	15,186
Salaries, general and administrative costs	13,004	12,725	10,764
Incentive compensation plan	523	1,722	1,510
Non-cash derivative expense	2,604	-	-
Merger expenses	25,785	1,297	-
Bad debt expense	2,343	-	-
Total expenses	506,268	191,617	165,985
Net income (loss) before income taxes	(107,772)	194,549	54,779
Income tax provision (benefit):			
Current	(489)	450	25
Deferred	(35,908)	67,642	17,688
Total income taxes	(36,397)	68,092	17,713
Net income (loss)	($71,375)	$126,457	$37,066
Earnings (loss) per common share:			
Basic earnings (loss) per share	($2.73)	$4.90	$1.61
Diluted earnings (loss) per share	($2.73)	$4.80	$1.58
Average shares outstanding	26,111	25,804	22,954
Average shares outstanding assuming dilution	26,111	26,335	23,416

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,		
	2001	2000	1999
Cash flows from operating activities:			
Net income (loss)	($71,375)	$126,457	$37,066
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	158,893	110,859	101,105
Deferred income tax provision (benefit)	(35,908)	67,642	17,688
Non-cash effect of production payments	(6,199)	(5,784)	(2,981)
Write-down of oil and gas properties	237,741	-	-
Other non-cash expenses	3,606	923	1,274
	286,758	300,097	154,152
(Increase) decrease in marketable securities	300	34,606	(18,053)
(Increase) decrease in accounts receivable	48,735	(45,661)	(13,223)
(Increase) decrease in other current assets	733	2,040	(1,663)
Increase (decrease) in other accrued liabilities	(13,279)	15,258	6,285
Investment in put contracts	(6,466)	(4,999)	-
Other	(1,164)	741	(4,488)
Net cash provided by operating activities	315,617	302,082	123,010
Cash flows from investing activities:			
Investment in oil and gas properties	(657,327)	(259,074)	(165,664)
Sale of unevaluated properties	1,366	4,302	10,630
Building additions and renovations	-	(1,160)	(405)
Increase in other assets	(886)	(2,705)	(3,128)
Net cash used in investing activities	(656,847)	(258,637)	(158,567)
Cash flows from financing activities:			
Proceeds from borrowings	131,000	59,500	67,500
Repayment of debt	(53,000)	(45,500)	(223,782)
Proceeds from issuance of 8¼% notes	200,000	-	-
Deferred financing costs	(6,794)	(200)	(538)
Proceeds from common stock offerings	-	-	198,242
Expenses from common stock offerings	-	-	(844)
Proceeds from exercise of stock options	4,822	4,404	2,048
Purchase of treasury stock	(200)	(743)	(299)
Net cash provided by financing activities	275,828	17,461	42,327
Net increase (decrease) in cash and cash equivalents	(65,402)	60,906	6,770
Cash and cash equivalents beginning of year	78,557	17,651	10,881
Cash and cash equivalents end of year	$13,155	$78,557	$17,651
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$3,992	$8,793	$15,648
Income taxes	-	450	25

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 (Deficit)	Other Comprehensive Income	Total Stockholders' Equity
Balance, December 31, 1998	$207	($2,571)	$232,430	($16,935)	-	$213,131
Net income	-	-	-	37,066	-	37,066
Sale of common stock	49	-	198,193	-	-	198,242
Expenses from common stock offerings	-	-	(844)	-	-	(844)
Exercise of stock options	1	-	2,047	-	-	2,048
Stock compensation plans	-	-	370	-	-	370
Tax benefit from stock option exercises	-	-	1,467	-	-	1,467
Exercise of warrants for common stock	-	(1,716)	1,716	-	-	-
Purchase of treasury stock	-	(669)	-	-	-	(669)
Issuance and vesting of restricted stock	1	-	2,058	-	-	2,059
Retirement of treasury stock	(1)	4,956	(4,955)	-	-	-
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	-	-	-	-	(26,114)	(26,114)
Net change in fair value of derivatives	-	-	-	-	33,720	33,720
Effect of change in accounting treatment for swaps	-	-	-	-	(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

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 and operation of oil and gas properties in the Gulf Coast Basin and Rocky Mountains.

Our business strategy is to increase production, cash flow and reserves through the acquisition and development of mature properties. Currently, our property base consists of 87 active properties, 55 in the Gulf Coast Basin and 32 in the Rocky Mountains, and 39 primary term leases. We serve as operator on 56 of our active properties, which enables us to better control the timing and cost of rejuvenation activities. We believe that there will continue to be opportunities to acquire properties in the Gulf Coast Basin due to the increased focus by major and large independent companies on projects away from the onshore and shallow water shelf regions of the Gulf of Mexico.

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. In connection with the approval of the merger, stockholders of Stone Energy also approved a proposal to increase the authorized shares of Stone common stock from 25,000,000 to 100,000,000 shares. Under the merger agreement, Basin stockholders received 0.3974 of a share of Stone common stock for each share of Basin common stock they owned. 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 in 2001. Merger expenses incurred by Basin in 2000 totaled $1,297.

The following table reconciles certain of Stone's pre-merger operating results with results reflecting the restatement of our financial statements under the pooling-of-interest method of accounting:

	2000			1999		
	Stone	Effects of Pooling	As Reported	Stone	Effects of Pooling	As Reported
Revenue...............	$260,379	$125,787	$386,166	$149,134	$71,630	$220,764
Net income...........	84,945	41,512	126,457	26,490	10,576	37,066

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 our 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 Stone's presentation.

The financial statements include our accounts, the accounts of our wholly owned subsidiaries and our proportionate interest in certain partnerships. These partnerships were dissolved on December 31, 1999. 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 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 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, 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, 2001 and 2000. The following table presents the carrying amounts and estimated fair values of our financial instruments at December 31, 2001 and 2000.

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
8¼% Senior Subordinated Notes due 2011...	$200,000	$201,880	$ -	$ -
8¾% Senior Subordinated Notes due 2007...	100,000	101,690	100,000	102,000
Put contracts..	26,207	26,207	4,999	7,669
Swap contracts	(5,813)	(5,813)	-	(42,846)

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 commodity 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.

Oil and gas properties included $113,372 and $55,691 of unevaluated property and related costs that were not being amortized at December 31, 2001 and 2000, respectively. The remainder of the unevaluated costs were associated with the acquisition and evaluation of unproved properties and major development projects expected to entail significant costs to ascertain quantities of proved reserves. We believe that a majority of unevaluated properties at December 31, 2001 will be evaluated within one to 24 months. The excluded costs and related reserve volumes 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, 2001 and 2000 was $6,000 and $4,027, 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. 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. At December 31, 2001, $53,117 of the acquisition cost was allocated to unevaluated properties based on our analysis of the acquired properties.

The following unaudited pro forma information details estimated operating results for 2001 and 2000 assuming the acquisition occurred on January 1, 2000:

	Year Ended December 31,	
	2001	2000
Revenues	$513,266	$542,545
Net income	17,879	177,208
Diluted net income per share	$0.68	$6.73

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

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, 2001 and 2000 included approximately $2,593 and $2,764, 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, 2001 and 2000 included approximately $9,291 and $2,637, respectively, of deferred financing costs, net of accumulated amortization, related to the issuance of the 8¾% and 8¼% Notes and the amendment of the credit facility (see Note 7). 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, 531,000 and 462,000 weighted-average dilutive shares for the years ending December 31, 2000 and 1999 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 279,000 shares and 71,000 shares during 2000 and 1999, 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.

Revenues 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, 2001, 2000 and 1999 were immaterial.

Income Taxes:

Income taxes are accounted for in accordance with 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 Standards:

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS No. 141 prohibits the use of the pooling-of-interest method of accounting for all business combinations initiated after June 30, 2001. SFAS No. 142 requires that goodwill not be amortized in any circumstances and also requires goodwill to be tested for impairment annually or when events or circumstances occur between annual tests indicating that goodwill for a reporting unit might be impaired. The standard establishes a new method for testing goodwill for impairment based on a fair value concept and is effective for fiscal years beginning after December 15, 2001. The adoption of SFAS Nos. 141 and 142 is not expected to have a material impact on our financial statements, because we do not have any goodwill recorded.

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 expect to adopt SFAS No. 143 on January 1, 2003. Upon adoption, we will be required to recognize cumulative transition amounts for existing asset retirement obligation liabilities, asset retirement costs and accumulated depreciation. We have not yet determined the transition amounts.

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, 2001, our put contracts were considered effective cash flow hedges, while our gas swap contracts, with a subsidiary of Enron, were not considered effective due to Enron's financial difficulties. (See Note 9)

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,	
	2001	2000
Accounts Receivable:		
Other co-venturers	$11,211	$12,697
Trade	35,371	75,670
Officers and employees	4	22
Unbilled accounts receivable	401	7,333
	$46,987	$95,722

NOTE 3 — CONCENTRATIONS:

Sales to Major Customers

Our production is sold without collateral 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,		
	2001	2000	1999
Adams Resources Energy, Inc.	(a)	(a)	10%
Columbia Energy Services	(a)	(a)	16%
Duke Energy Corporation	(a)	11%	(a)
Dynegy, Incorporated	(a)	(a)	11%
El Paso Merchant Energy, LP	26%	13%	(a)
Enron North America Corporation	19%	10%	(a)
Northridge Energy Marketing	(a)	(a)	12%

(a) less than 10 percent

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

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

Production Volumes

Production from South Pelto Block 23 and Eugene Island Block 243 each accounted for approximately 16% of our total oil and gas production volumes during 2001.

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,		
	2001	2000	1999
Oil and gas properties—			
Balance, beginning of year	$1,368,084	$1,098,940	$904,456
Costs incurred during year:			
Capitalized—			
Acquisition costs, net of sales of unevaluated properties	328,778	15,086	27,316
Exploratory drilling	176,679	138,420	66,848
Development drilling	119,426	98,004	86,218
Employee, general and administrative costs and interest	16,720	19,234	15,440
Less: overhead reimbursements	(326)	(1,600)	(1,338)
Total costs incurred during year	641,277	269,144	194,484
Balance, end of year	$2,009,361	$1,368,084	$1,098,940
Charged to expense—			
Operating costs:			
Normal lease operating expenses	$47,564	$41,474	$33,372
Major maintenance expenses	6,508	6,538	1,115
Total operating costs	54,072	48,012	34,487
Production taxes	6,408	7,607	2,933
	$60,480	$55,619	$37,420
Unevaluated oil and gas properties—			
Costs incurred during year:			
Acquisition costs	$77,311	$22,760	$22,381
Exploration costs	-	6,229	806
	$77,311	$28,989	$23,187
Accumulated depreciation, depletion and amortization—			
Balance, beginning of year	($620,510)	($511,279)	($412,107)
Provision for depreciation, depletion and amortization	(157,204)	(109,231)	(99,172)
Write-down of oil and gas properties	(237,741)	-	-
Balance, end of year	(1,015,455)	(620,510)	(511,279)
Net capitalized costs (proved and unevaluated)	$993,906	$747,574	$587,661
DD&A per Mcfe	$1.70	$1.10	$1.08

At December 31, 2001 and 2000, unevaluated oil and gas properties of $113,372 and $55,691, respectively, were not subject to depletion. Of the $113,372 in unevaluated costs at December 31, 2001, $77,311 was incurred in 2001 and $36,061 was incurred in prior years. We believe that a majority of unevaluated properties will be evaluated within one to 24 months.

NOTE 5 — INCOME TAXES:

An analysis of our deferred taxes follows:

	As of December 31,	
	2001	2000
Net operating loss carryforward	$9,795	$8,056
Statutory depletion carryforward	4,787	4,527
Contribution carryforward	158	112
Capital loss carryforward	43	43
Alternative minimum tax credit carryforward	812	1,142
Temporary differences:		
Oil and gas properties — full cost	(48,617)	(83,773)
Hedges	(4,214)	-
Other	1,838	967
Valuation allowance	(158)	-
	($35,556)	($68,926)

For tax reporting purposes, operating loss carryforwards totaled approximately $27,984 at December 31, 2001. If not utilized, such carryforwards would begin expiring in 2009 and would completely expire by the year 2021. In addition, we had approximately $14,195 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.

During 1999, our provision for income taxes was net of a $1,460 reduction in deferred taxes related to estimates of tax basis that were resolved during 1999. In order to conform Stone and Basin's accounting methods, we recognized the $5,729 tax benefit related to Basin's 1998 write-down of oil and gas properties by reversing the valuation allowance that Basin recorded in 1998. This resulted in additional deferred tax benefit for the year ended December 31, 1998 and deferred tax expense for the years ended December 31, 1999 and 2000. During 1999 and 2000, Basin had previously reduced its effective tax rate through the reversal of the valuation allowance recorded in 1998. 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,		
	2001	2000	1999
Income tax expense (benefit) computed at the statutory federal income tax rate	(35%)	35%	35%
Non-deductible portion of merger expenses	2%	-	-
Other	(1%)	-	(3%)
Effective income tax rate	(34%)	35%	32%

Income tax expense allocated to other comprehensive income amounted to $4,036 for 2001.

NOTE 6 — PRODUCTION PAYMENTS:

In June 1999, we acquired a 100% working interest in the Lafitte Field by executing an agreement that included a dollar-denominated production payment to be satisfied through the sale of production from the purchased property. At that time, we recorded a production payment of $4,600 representing the estimated discounted present value of production payments to be made. As provided for in a separate agreement, on September 23, 1999, Goodrich Petroleum Company, L.L.C. exercised its option to participate for a 49% working interest in the Lafitte Field resulting in a reduction of the production payment to $2,346 at September 30, 1999. At December 31, 2001, the production payment associated with this transaction totaled $1,335.

In July 1999, we acquired an additional working interest in East Cameron Block 64 and a 100% working interest in West Cameron Block 176 in exchange for a volumetric production payment. This agreement requires that 7.3 MMcf of gas per day be delivered to the seller from South Pelto Block 23 until 8 Bcf of gas have been distributed. At the transaction date, we recorded a volumetric production payment of $17,926 representing the estimated discounted cash flows associated with the specific production volumes to be delivered. We amortize the volumetric production payment as specified deliveries of gas are made to the seller and recognize non-cash revenue in the form of gas production revenue. At December 31, 2001, the volumetric production payment was $2,988 and gas revenues of $5,975 were recognized during 2001.

NOTE 7 — LONG-TERM DEBT:

Long-term debt consisted of the following at:

	December 31,	
	2001	2000
8¼% Senior subordinated notes due 2011	$200,000	$ -
8¾% Senior subordinated notes due 2007	100,000	100,000
Bank debt	126,000	48,000
Total long-term debt	$426,000	$148,000

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 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, 2001, $723 had been accrued in connection with the June 15, 2002 interest payment.

At December 31, 2001 and 2000, long-term debt included of $100,000 8¾% Senior Subordinated Notes due 2007 and there were no minimum principal payments due for the next five years. At December 31, 2001, $2,601 had been accrued in connection with the March 15, 2002 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, 2001, we had $126,000 of borrowings outstanding under our bank credit facility and letters of credit totaling $7,347 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, 2001, Stone had $116,653 of borrowings available under the amended credit facility. The weighted average interest rate under the amended credit facility was approximately 3.4% at December 31, 2001. 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. Our credit facility provides for certain covenants, including restrictions or requirements with respect to debt to EBITDA ratio, tangible net worth, disposition of properties, incurrence of additional debt, change of ownership and reporting responsibilities. These covenants may limit or prohibit us from paying cash dividends.

Concurrent with closing the merger on February 1, 2001, borrowings of $48,000 outstanding under Basin Exploration's bank credit facility were repaid with cash on hand and the credit facility was terminated.

NOTE 8 — 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 various net profit interests granted at the time of acquisition to certain of our officers and other employees. Such net profit interest owners do not receive any cash distributions until we have recovered all acquisition, development, financing and operating costs. We believe the estimated value of these interests at the time of acquisition is not material to our financial position or results of operations. Effective January 1, 2001, we acquired the net profit interests from our employees through a final settlement payment and discontinued this benefit program. Two of our officers remain net profit interest owners. Amounts paid to officers under the remaining net profits arrangement amounted to $1,777, $1,085 and $79 in 2001, 2000 and 1999, respectively.

We received certain fees as a result of our function as managing partner of certain partnerships. These partnerships were dissolved on December 31, 1999. All participants in the partnerships, including four of our directors, James H. Stone, Joe R. Klutts, Raymond B. Gary and Robert A. Bernhard, received overriding royalty interests in the related properties in exchange for their partnership interests. For the year ended December 31, 1999, management fees and overhead reimbursements from partnerships totaled $224, the majority of which was treated as a reduction of our investment in oil and gas properties. Until their dissolution, we collected and distributed production revenue as managing partner for the partnerships' interests in oil and gas properties.

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 received $56 and $41 during 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 and Audit Committee members, 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 2001 in the amount of $255.

The law firm of Gordon, Arata, McCollam, Duplantis and Eagan, of which B.J. Duplantis, one of our Directors and Audit Committee members, is a Senior Partner, provided legal services for us during 2001 and 2000. The value of these services totaled approximately $20 and $9 during 2001 and 2000, respectively.

NOTE 9 — HEDGING ACTIVITIES:

We enter into hedging transactions to secure a price for a portion of future production that is acceptable at the time at which the transaction is entered. The primary objective of these activities is to reduce our exposure to the possibility of declining oil and gas prices during the term of the hedge. These hedges are designated as cash flow hedges 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 oil and gas revenue. Any amount received or paid related to terminated contracts are amortized over the original contract period and reflected in revenue from oil and gas production.

At December 31, 2000, our oil put contracts were reflected as assets at a historical cost of $4,999 and, in accordance with generally accepted accounting principles in effect at year-end 2000, our fixed price gas swap contracts were not reflected in the financial statements since they were costless. Our gas put contracts were purchased subsequent to year-end and therefore were not reflected in the December 31, 2000 balance sheet.

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. In addition, the fair market value of the fixed price gas swaps was recorded as a liability and the corresponding after-tax loss of $27,850 was recorded in equity through other comprehensive income.

At December 31, 2001, our oil and gas puts were reflected as assets at a fair value of $26,207. Our oil put contracts are with Bank of America, N.A. and our gas put contracts are with J. Aron & Co. 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 addition to put contracts, we utilized fixed price swaps to hedge a portion of our future gas production. Fixed price swaps typically provide for monthly payments by us if NYMEX prices rise above the fixed swap price or to us if NYMEX prices fall below the fixed swap price. At December 31, 2001,our swap contracts were reflected as liabilities at fair value of $5,813.

Our natural gas swap contracts are with a subsidiary of Enron Corp. Due to Enron's financial difficulties, there is no assurance that we will receive full or partial payment of any amounts that may become owed to us under these contracts. Accordingly, these swaps no longer qualify as effective hedges under SFAS No. 133. As a result, the changes in fair value for each period will now be recorded through earnings and amounts previously recorded in other comprehensive income will be amortized through earnings over the remaining life of the swaps. At December 31, 2001, other comprehensive income included $4,109 related to the natural gas swaps that will be amortized over the remaining life of the swap contracts. Included in the 2001 non-cash derivative expense is a $169 gain from amortization of other comprehensive income and a $340 gain related to the changes in the fair value of the swaps.

Since 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, 2002.

	Puts					
	Gas			Oil		
	Volume (BBtus)	Floor	Cost	Volume (Bbls)	Floor	Cost
2002	21,900	$3.50	$5,201	1,277,500	$24.00	$3,152

	Fixed Price Gas Swaps	
	Volume (BBtus)	Price
2002	3,650	$2.15
2003	3,650	$2.15

For the years ended December 31, 2001, 2000 and 1999, we realized net decreases in oil and gas revenue related to hedging transactions of $1,819, $47,899, and $11,295, respectively.

NOTE 10 — 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.

On July 28, 1999, Stone Energy completed an offering of 3,162,500 shares of its common stock at a price to the public of $43.75 per share. After payment of the underwriting discount and related expenses, Stone received net proceeds of $130,760.

On June 23, 1999, Basin Exploration completed an offering of 4,312,500 shares (approximately 1,713,788 shares post merger) of its common stock at a price to the public of $16.50 per share (approximately $41.52 per share post merger). After payment of the underwriting discount and related expenses, Basin received net proceeds of $66,638.

NOTE 11 — COMMITMENTS AND CONTINGENCIES:

We lease office facilities in New Orleans, Louisiana, Denver, Colorado and at 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 2004. The minimum net annual commitments under all leases, subleases and contracts noted above at December 31, 2001 were as follows:

2002	$1,075
2003	1,046
2004	1,045
2005	508
2006	98
Thereafter	-

Payments related to our lease obligations for the years ended December 31, 2001, 2000 and 1999 were approximately $1,280, $1,146 and $859, respectively. We sublease office space to third parties, and for the years ended 2001, 2000 and 1999 we recorded related receipts of $285, $181 and $186, respectively. Minimum lease rentals to be received from the sublease of office space is $239 for each of the years ended December 31, 2002, 2003 and 2004.

Until December 31, 1999, we were the managing general partner of eight partnerships and are contingently liable for any recourse debts and other liabilities that may result from their operations until dissolution. We are not aware of the existence of any such liabilities that would have a material impact on future operations.

We are contingently liable to surety insurance companies in the aggregate amount of $41,304 relative to bonds issued on our behalf to the 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.

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.

NOTE 12 — EMPLOYEE BENEFIT PLANS:

We have entered into deferred compensation and disability agreements with certain of our officers whereby we have purchased split-dollar life insurance policies to provide certain retirement and death benefits for certain of our officers and death benefits payable to us. The aggregate death benefit of the policies was $3,139 at December 31, 2001, of which $1,975 was payable to certain officers or their beneficiaries and $1,164 was payable to us. Total cash surrender value of the policies, net of related surrender charges at December 31, 2001, was approximately $994. Additionally, the benefits under the deferred compensation agreements vest after certain periods of employment, and at December 31, 2001, the liability for such vested benefits was approximately $842. 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, net cash flows and net asset value. Incentive bonuses are awarded to participants based upon individual performance factors. Stone incurred expenses of $523, $1,722 and $1,510, net of amounts capitalized, for the years ended December 31, 2001, 2000 and 1999, respectively, related to incentive compensation bonuses paid under this program.

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. 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.

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, 2001, 2000 and 1999, Stone contributed $688, $445 and $313, respectively, to the plan.

The following Basin benefit plans were in effect during portions of the periods presented but were terminated upon consummation of the merger on February 1, 2001. Unless otherwise indicated, the following share amounts do not reflect the conversion factor of .3974 of a share of Stone common stock for each share of Basin common stock:

i. Basin Exploration had a 401(k) profit sharing plan. All Basin employees who joined Stone were eligible to participate in Stone's 401(k) plan based on years of service with Basin. In the month of January 2001, Basin contributed $13 to the Basin 401(k) profit sharing plan prior to termination. During 2000 and 1999, Basin contributed $383 and $241, respectively, to the Basin 401(k) profit sharing plan.

ii. Under the Equity Incentive Plan, Basin's officers, key employees, consultants and directors were eligible to receive incentive stock options, non-qualified stock options, restricted stock and performance shares. At December 31, 2000, approximately 1,599,000 shares were available for grant under the plan. Of this total, an aggregate of 1,283,000 shares of Basin common stock were subject to prior issuances under such plan, including 182,000 non-vested shares of restricted stock and performance shares and 1,100,000 outstanding stock options.

    Basin granted 19,000 shares of restricted stock during 2000. Approximately $206, $291 and $466 of related compensation expense was recognized during 2001, 2000 and 1999, respectively. As of December 31, 2001 only 2,514 shares of restricted stock, as converted to Stone shares, remained subject to future vesting in 2002 and 2003. With the consummation of the merger, no further grants of restricted stock were made and after the remaining shares are vested this plan will be terminated.

Basin granted 50,000 and 55,000 performance shares during 2000 and 1999, respectively. Expense was recognized based on vesting schedules, projections of performance and changes in the price of Basin common stock during the applicable vesting periods. Related compensation expense of $640 and $1,593 was recognized during 2000 and 1999, respectively. All outstanding performance shares at February 1, 2001 were forfeited.

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 cost for stock-based compensation plans had been determined consistent with the expense recognition provisions under SFAS No. 123, our 2001, 2000 and 1999 net income (loss) and basic and diluted earnings (loss) per common share would have approximated the pro forma amounts below:

	Year Ended December 31,					
	2001		2000		1999	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
Net income (loss)	($71,375)	($74,944)	$126,457	$121,248	$37,066	$33,957
Earnings (loss) per common share:						
Basic	($2.73)	($2.87)	$4.90	$4.70	$1.61	$1.48
Diluted	($2.73)	($2.87)	$4.80	$4.60	$1.58	$1.45

A summary of stock options as of December 31, 2001, 2000 and 1999 and changes during the years ended on those dates is presented below.

	Year Ended December 31,					
	2001		2000		1999	
	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	1,880,077	$34.39	1,771,668	$27.22	1,428,029	$21.95
Granted	588,200	48.72	455,045	51.92	530,197	37.47
Expired	(163,861)	47.18	(13,000)	23.95	(34,923)	22.73
Exercised	(245,885)	28.81	(333,636)	20.52	(151,635)	15.96
Outstanding at end of year	2,058,531	$38.04	1,880,077	$34.39	1,771,668	$27.22
Options exercisable at year-end	963,761	27.95	808,072	24.48	782,082	20.29
Options available for future grant	910,750		957,250		299,750	
Weighted average fair value of options granted during the year	$23.86		$28.65		$22.87	

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 44.24%, 45.72% and 47.18% in the years 2001, 2000 and 1999, respectively, (c) risk-free interest rate of 4.88%, 6.76% and 6.07% in the years 2001, 2000 and 1999, 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, 2001:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Options Outstanding at 12/31/01	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable at 12/31/01	Wgtd. Avg. Exercise Price
\$9 – \$20	206,110	2.3 years	\$12.37	206,110	\$12.37
20 – 30	490,154	4.6 years	24.09	412,830	23.67
30 – 40	585,145	6.8 years	36.83	226,620	36.04
40 – 50	146,000	8.5 years	45.80	30,200	45.44
50 – 61.93	631,122	7.8 years	56.59	88,001	57.73
	2,058,531	6.2 years	38.04	963,761	27.95

NOTE 13 — OIL AND GAS RESERVE INFORMATION – UNAUDITED:

Our net proved oil and gas reserves at December 31, 2001 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, 1998	27,143	370,772
Revisions of previous estimates	3,961	(7,027)
Extensions, discoveries and other additions	3,305	67,001
Purchase of producing properties	5,128	19,101
Production (1)	(4,324)	(64,180)
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
Proved developed reserves:		
as of December 31, 1999	25,194	309,696
as of December 31, 2000	25,374	307,320
as of December 31, 2001	43,094	351,269

(1) Excludes gas production volumes related to the volumetric production payment. See "Note 6 – Production Payments."

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 2001 year-end product prices for all of our properties were $18.64 per barrel of oil and $2.79 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 13 — OIL AND GAS RESERVE INFORMATION – UNAUDITED: (Continued)

	Standardized Measure Year Ended December 31,		
	2001	2000	1999
Future cash flows	$2,274,665	$4,902,297	$1,806,565
Future production and development costs	(767,442)	(701,533)	(613,129)
Future income taxes	(212,883)	(1,392,078)	(215,879)
Future net cash flows	1,294,340	2,808,686	977,557
10% annual discount	(385,764)	(825,937)	(286,076)
Standardized measure of discounted future net cash flows	$908,576	$1,982,749	$691,481

	Changes in Standardized Measure Year Ended December 31,		
	2001	2000	1999
Standardized measure at beginning of year	$1,982,749	$691,481	$418,403
Sales and transfers of oil and gas produced, net of production costs	(333,200)	(368,243)	(178,007)
Changes in price, net of future production costs	(2,097,695)	1,784,727	326,300
Extensions and discoveries, net of future production and development costs	134,876	656,944	138,945
Changes in estimated future development costs, net of development costs incurred during the period	61,994	30,608	13,348
Revisions of quantity estimates	(19,982)	(162,462)	28,735
Accretion of discount	294,179	83,064	45,059
Net change in income taxes	828,820	(819,893)	(108,160)
Purchases of reserves in-place	314,394	48,752	60,065
Changes in production rates due to timing and other	(257,559)	37,771	(53,207)
Standardized measure at end of year	$908,576	$1,982,749	$691,481

NOTE 14 — SUMMARIZED QUARTERLY FINANCIAL INFORMATION – UNAUDITED:

	Revenues	Expenses	Net Income (Loss)	Basic Earnings (Loss) Per Share	Diluted Earnings (Loss) Per Share
2001					
First Quarter	$144,001	$104,742	$39,259	$1.51	$1.49
Second Quarter	106,729	77,661	29,068	1.11	1.10
Third Quarter	83,082	228,150	(145,068)	(5.54)	(5.54)
Fourth Quarter	64,684	59,318	5,366	0.20	0.20
	$398,496	$469,871	($71,375)	(2.73)	(2.73)
2000					
First Quarter	$70,869	$53,097	$17,772	$0.69	$0.68
Second Quarter	84,302	59,007	25,295	0.98	0.96
Third Quarter	109,547	72,165	37,382	1.45	1.42
Fourth Quarter	121,448	75,440	46,008	1.78	1.74
	$386,166	$259,709	$126,457	4.90	4.80

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.

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.

EBITDA. Represents net income attributable to common stock plus interest, income taxes, depreciation, depletion and amortization and non-cash ceiling test write-downs of oil and gas properties.

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.

Farmin or farmout. An agreement under which the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farmin" while the interest transferred by the assignor is a "farmout."

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.

MBbls/d. One thousand barrels of crude oil or other liquid hydrocarbons per day.

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.

Mcf/d. One thousand cubic feet of gas per day.

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.

MMcf/d. One million cubic feet of gas 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.

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%.

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.

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

Tcf. One trillion cubic feet of gas.

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.

BOARD OF DIRECTORS

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D. Peter Canty
President and Chief Executive Officer

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Craig L. Glassinger
Vice President—Resources

Eldon J. Louviere
Vice President—Land

J. Kent Pierret
Vice President—Controller and
Chief Accounting Officer

James H. Prince
Vice President and Chief Financial Officer

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ANNUAL MEETING

The Company's annual meeting of stockholders will be held at 10:00 a.m. on May 16, 2002 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 can be accessed through the website.

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