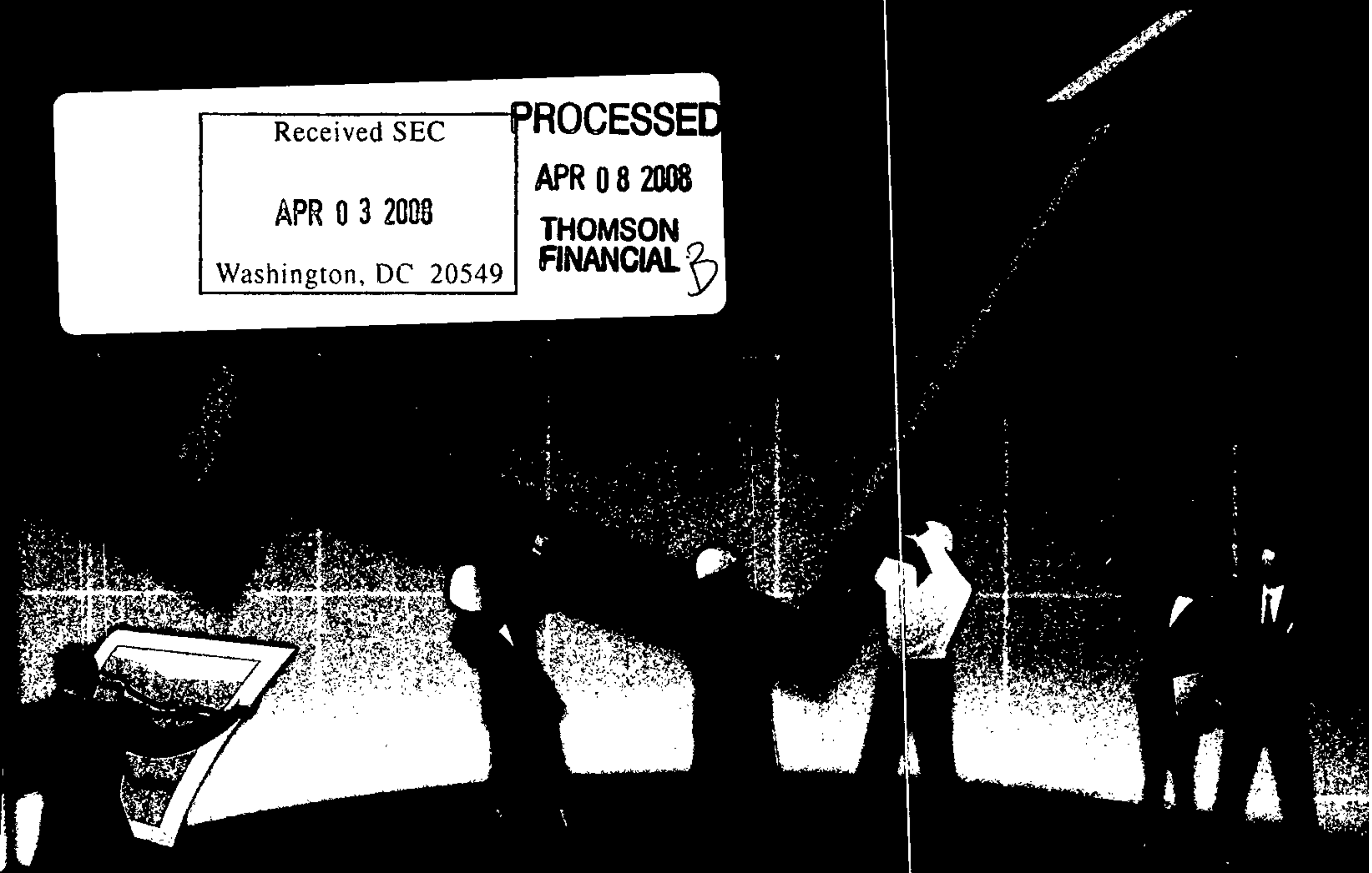
STONE ENERGY



2007 Annual Report

Stone Energy Corporation is an independent oil and natural gas exploration and production company headquartered in Lafayette, Louisiana. Our business strategy is to increase stockholder value through the acquisition, exploration and development of oil and natural gas in mature and emerging fields. Stone currently operates primarily in the Gulf of Mexico and onshore Louisiana.

2007 Significant Events

- **Implementation of Re-focus Strategy**—In early 2007, Stone re-focused on the Gulf of Mexico through lower risk exploitation projects.
- **Rocky Mountain Property Sale**—In June, Stone completed the sale of substantially all of its Rocky Mountain properties for a total cash consideration of approximately $578 million, while maintaining an interest in several undeveloped plays.
- **Debt Reduction**—The proceeds from the Rocky Mountain property sale were used to materially reduce debt. Stone fully paid down its outstanding bank borrowings of $109 million and redeemed its $225 million Senior Floating Rate Notes.
- **Future Growth**—In June, Richard L. Smith was appointed as Vice President of Exploration and Business Development. In October, Stone was the high bidder at the Minerals Management Service Outer Continental Shelf Sale 205 on sixteen offshore blocks totaling $12.9 million, including ten deep water blocks. Separately, drilling and seismic activities were performed in the exploratory joint venture in Bohai Bay, China. Stone also began to acquire acreage in selected areas of Appalachia during the year.

Summary Financial and Reserve Data

(In thousands, except per share data)

Year Ended December 31,	2007	2006	2005	2004	2003
Oil and gas revenues	$ 753,252	$ 686,300	$ 636,240	$ 544,201	$ 508,305
Income (loss) from operations	285,540	(365,249)	232,467	199,307	208,222
Net income (loss)	181,436	(254,222)*	136,764	119,668	123,192
Basic earnings (loss) per common share	$ 6.57	$ (9.29)	$ 5.07	$ 4.50	$ 4.67
Diluted earnings (loss) per common share	6.54	(9.29)	5.02	4.45	4.64
Weighted average shares outstanding (basic)	27,612	27,366	26,951	26,586	26,353
Weighted average shares outstanding (diluted)	27,723	27,366	27,244	26,901	26,546
Net cash provided by operating activities	$ 465,158	$ 399,035	$ 461,213	$ 369,668	$ 390,811
Net cash provided by (used in) investing activities	344,812	(660,456)	(499,932)	(475,159)	(341,180)
Net cash provided by (used in) financing activities	(393,706)	240,575	94,170	112,648	(60,140)
Total assets	$1,889,603	$2,128,471	$2,140 317	$1,695,664	$1,332,485
Long-term debt	400,000	797,000	563 000	482,000	370,000
Stockholders' equity	885,802	711,640	944 123	772,934	644,111
Oil and condensate reserves (MBbls)	31,586	41,360	41,509	42,385	44,508
Gas reserves (MMcf)	213,083	342,782	344,088	413,902	380,280
Total proved reserves (MMcfe)	402,598	590,942	593,142	668,210	647,326

*Includes the impact of an after-tax charge of $330.5 million due to a ceiling test write-down.

Dear Fellow Stockholders,

This past year was a good one for Stone Energy. During the year, we focused the company by divesting our Rockies production, conserved capital, paid down debt and still managed to slightly grow our production and replace production with new reserves. We exited 2007 with zero net debt, an expanded capital budget for 2008, a wide array of options and lots of enthusiasm.

At the start of 2007, we identified and articulated a number of key objectives designed to position Stone for the future by strengthening our financial and operational position. During the year we achieved or exceeded all of these objectives.

Focus Capital on Low Risk Exploitation

Virtually all of the wells drilled in 2007 were low risk exploitation wells and we delivered a drilling success rate of over 90%. Most of these wells were able to commence production shortly after being drilled, with few new facilities or pipelines being needed. We also created and maintained a three year inventory of exploitation projects and intend to continue with this program into 2008 and beyond.

Control Costs

Our operations group was able to reduce lease operating expenses in 2007 despite overall oil field cost inflation. We derived benefits from our supply chain management effort, reduced our vessel and helicopter usage, managed our insurance costs and took proactive steps with preventative maintenance, which improved the integrity of our operations.

Maintain Production While Conserving Capital

The focus of our 2007 program was to maintain production through exploitation drilling, well workover projects, compressor programs, reduced downtime and field optimization. Despite spending less than half of our cash flow and completing the sale of our Rocky Mountain properties at mid-year, we were able to increase production volumes over the previous year.

Strategically Exit the Rockies

The favorable value accorded our Rocky Mountain properties last year, combined with our concerns over price differentials, led to our decision to divest our Rocky Mountain properties as an ongoing unit. We executed an efficient and effective sales process and closed the sale of these assets at mid-year. We were pleased to receive cash proceeds of $578 million for these properties, while also retaining a 35% working interest in several of our exploration plays.

Significantly Reduce Debt

Stone started the year with $797 million in debt, which restricted our alternatives and opportunities. However, with our capital conservation program and the sale of our Rockies properties, we were able to redeem $225 million of Senior Floating Rate Notes and completely pay down our bank debt. At year-end we had over $475 million in cash while debt was down to $400 million in Subordinated Notes due 2011 and 2014, leaving us with no net debt and excess cash.

Generate Positive Returns

With a capital conserving budget, we were able to focus on profitable projects while bolstering the balance sheet. Our book equity increased by almost $175 million during the year. In the fourth quarter of 2007, our Board of Directors authorized a share repurchase program of up to $100 million, which we may use in the future to increase per share returns.

A lot of hard work was put in by the Stone Energy employees to accomplish these goals, and their effort and success is acknowledged and is greatly appreciated.

Outlook for 2008

In 2007, we were able to lay the groundwork for future growth by rebuilding our exploration and business development effort. While our exploitation projects provide us with production and cash flow, our exploration and business development groups are charged with providing profitable future reserve and production growth.

Exploration

We expect to cautiously re-enter the exploration business and will drill a number of exploratory wells in 2008. The exploration plan includes drilling prospects at appropriate ownership levels in the Gulf of Mexico (GOM), onshore in Louisiana, in Bohai Bay and possibly a residual prospect in the Rocky Mountain region. We will participate in the GOM lease sale and continue to add to our seismic library. We have assembled an experienced exploration team and expect to see positive results from the 2008 program.

Business Development

Our strong balance sheet and cash position allows us to review numerous acquisition and drill-to-earn opportunities both offshore and onshore. We remain hopeful that our efforts in this area will provide Stone with properties for future exploration and exploitation projects. We anticipate the capture and testing of an Appalachian shale resource play in 2008.

In summary, the company is in excellent financial condition, has a multi-year inventory of lower risk exploitation opportunities, is well positioned to execute opportunistic acquisitions, has an expanding inventory of exploration and business development prospects and has an experienced team in place to successfully execute a profitable growth strategy. We are excited and optimistic about our prospects for 2008 and beyond.

We greatly appreciate the support and look forward to delivering value to you, our stockholders.

Sincerely,

David H. Welch
President and Chief Executive Officer

Board of Directors

Robert A. Bernhard [1,4]
MB Investment Partners
Consultant

Lt. Gen. George R. Christmas (Ret.) [2,4]
Marine Corps Heritage Foundation
President and Chief Executive Officer

B.J. Duplantis [3,4]
Gordon, Arata, McCollam, Duplantis & Eagan
Senior Partner

John P. Laborde [3]
Tidewater Inc.
Retired Chairman Emeritus

Richard A. Pattarozzi [2,3,4]
Shell Oil Company
Former Vice President

Kay G. Priestly [1,3,4]
Kennecott Utah Copper
Vice President, Finance, and Chief Financial Officer

David R. Voelker [1,2,4]
Frantzen, Voelker and Conway Investments, LLC
Owner

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

[1] Audit Committee [2] Compensation Committee [3] Reserves Committee [4] Nominating and Governance Committee

Senior Management

David H. Welch
President and Chief Executive Officer

Kenneth H. Beer
Senior Vice President and Chief Financial Officer

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

E. J. Louviere
Senior Vice President—Land

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

Richard L. Smith
Vice President—Exploration and Business Development

Jerome F. Wenzel, Jr.
Senior Vice President—Operations/Exploitation

Florence M. Ziegler
Vice President—Human Resources and Administration

Mr. James H. Stone
Founder and Chairman of Stone Energy Corporation
December 20, 1925–January 14, 2008

Mr. James H. Stone started his first oil and gas company in 1952 and brought Stone Energy Corporation public on the New York Stock Exchange in 1993. His dedication, hard work and leadership paved the way for a small start-up company to develop into a substantial oil and gas exploration and production company. Under his direction, the company grew to a market capitalization of over $1.5 billion. Mr. Stone remained Chairman of the Board of Stone Energy Corporation until his death.

Mr. Stone will be remembered for his civic leadership, for his service to his country as a Marine, for his commitment to the oil and gas industry as an entrepreneur and businessman, and as a friend, mentor and family man.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______.

Commission File Number: 1-12074

STONE ENERGY CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

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

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. [X]Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. [ ] Yes [x] No

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. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [x]   Accelerated filer [ ]   Non-accelerated filer [ ]   Smaller reporting company [ ]

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $894,884,596 as of June 30, 2007 (based on the last reported sale price of such stock on the New York Stock Exchange Composite Tape on that day).

As of February 11, 2008, the registrant had outstanding 28,297,399 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 15, 2008 are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

PART I

This section highlights information that is discussed in more detail in the remainder of the document. Throughout this document we make statements that are classified as "forward-looking." Please refer to the "Forward-Looking Statements" section beginning on page 7 of this document for an explanation of these types of statements. We use the terms "Stone", "Stone Energy", "company", "we", "us" and "our" to refer to Stone Energy Corporation. Certain terms relating to the oil and gas industry are defined in "Glossary of Certain Industry Terms", which begins on page G-1 of this Form 10-K.

ITEM 1. BUSINESS

The Company

Stone Energy is an independent oil and natural gas company engaged in the acquisition and subsequent exploration, development, operation and production of oil and gas properties located primarily in the Gulf of Mexico ("GOM"). Prior to June 29, 2007, we also had significant operations in the Rocky Mountain Basins and the Williston Basin (Rocky Mountain Region). We are also engaged in an exploratory joint venture in Bohai Bay, China and have begun acquiring leasehold interests in Appalachia. Our corporate headquarters are located at 625 E. Kaliste Saloom Road, Lafayette, Louisiana 70508.

Available Information

We make available free of charge on our Internet web site (www.stoneenergy.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the Securities and Exchange Commission (the "SEC"). In addition, the public may read and copy any materials filed by us with the SEC at the SEC's Public Reference Room at 450 Fifth Street, NW, Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (http://www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. We also make available on our Internet web site our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation and Nominating and Governance Committee Charters, respectively, which have been approved by our board of directors. We will make immediate disclosure by a Current Report on Form 8-K and on our web site of any change to, or waiver from, the Code of Business Conduct and Ethics for our principal executive and senior financial officers. A copy of our Code of Business Conduct and Ethics is also available, free of charge by writing us at: Chief Financial Officer, Stone Energy Corporation, P.O. Box 52807, Lafayette, LA 70505. The annual CEO certification required by Section 303A.12 of the New York Stock Exchange Listed Company Manual was submitted on May 24, 2007.

Strategy and Operational Overview

Since our public offering in 1993, we have been engaged in the acquisition, exploration and development of mature oil and gas properties in the Gulf Coast Basin, which includes onshore Louisiana and offshore GOM. During 2004, we broadened our conventional shelf acquisition and exploitation strategy in order to diversify, extend reserve life and take advantage of a strong oil and gas market. This broadened growth strategy included targeting reserves and production in the deep shelf and deep water of the GOM, furthering our position in the Rocky Mountain Region to complement our existing portfolio of properties in the Gulf Coast Basin (onshore, shelf and deep shelf) and investigating viable opportunities in other areas including international areas. In December 2006, we announced that our Board of Directors had approved and endorsed a strategic plan to re-focus on our Gulf of Mexico conventional shelf properties. On June 29, 2007, we completed the sale of substantially all of our Rocky Mountain Region properties and related assets to Newfield Exploration Company in two separate transactions for a total consideration of $582 million. As part of this renewed strategy, we anticipate further investment in our assets in Bohai Bay, China in 2008 to bring the project to evaluation. Additionally, we anticipate pursuing alternatives in the deep water Gulf of Mexico and Appalachia on a selected basis.

Gulf of Mexico — Conventional Shelf (Including Onshore Louisiana)

Our conventional shelf strategy is the same acquisition and exploitation combination that we adopted prior to our initial public offering in 1993. We apply the latest geophysical interpretation tools to identify underdeveloped properties and the latest production techniques to increase production attributable to these properties. We seek to acquire properties that have the following characteristics:

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

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

Gulf of Mexico — Deep Water/ Deep Shelf

We believe that the deep water of the GOM is an important exploration area, even though it involves high risk, high costs and substantial lead time to develop infrastructure. We have made a significant investment in seismic data and have assembled a technical team with prior geological, geophysical and engineering experience in the deep water arena to evaluate potential opportunities. As of yet, we have no production or proved reserves in the deep water of the GOM.

Our current property base also contains multiple deep shelf exploration opportunities in the GOM, which are defined as prospects below 15,000 feet. The deep shelf presents higher risk with high potential opportunities usually with existing infrastructure, which shortens the lead time to production.

Rocky Mountain Region

On June 29, 2007, we completed the sale of substantially all of our Rocky Mountain Region properties and related assets to Newfield Exploration Company. At December 31, 2006, the estimated proved reserves associated with these assets totaled 182.4 Bcfe, which represented 31% of our estimated proved oil and natural gas reserves. The divested properties included our interests in the Pinedale Anticline, the Jonah field, the Williston Basin, the Scott field and several smaller producing areas. The sale also included net undeveloped acreage of approximately 550,000 acres. We maintained working interests in several undeveloped plays in the Rocky Mountain Region, which totaled approximately 96,000 net acres as of February 11, 2008.

International

During 2006, we entered into an agreement to participate in the drilling of exploratory wells on two offshore concessions in Bohai Bay, China. After the drilling of three wells it has been determined that additional drilling will be necessary to evaluate the commercial viability of this project. We have the potential to earn an interest in 750,000 acres on these two concessions.

Appalachia

During 2007, we began securing leasehold interests in Pennsylvania and are investigating other investments in this area. As of February 11, 2008, we had secured leasehold interests in approximately 20,000 net acres. We anticipate drilling two to three exploratory wells in this region in 2008.

Oil and Gas Marketing

Our oil and natural gas production is sold at current market prices under short-term contracts. Chevron Texaco E&P Company, Conoco, Inc., and Shell Trading (US) Company, each accounted for between 11%-19% of oil and natural gas revenue generated during the year ended December 31, 2007. No other purchaser accounted for 10% or more of our total oil and natural gas revenue during 2007. We believe that the loss of any of our major purchasers would not result in a material adverse effect on our ability to market future oil and gas production. From time to time, we may enter into transactions that hedge the price of oil and natural gas. See **"Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk."**

Competition and Markets

Competition in the Gulf Coast Basin, the Rocky Mountain Region and Appalachia is intense, particularly with respect to the acquisition of producing properties and undeveloped acreage. We compete with major oil and gas companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of our competitors have financial resources and exploration and development budgets that are substantially greater than ours, which may adversely affect our ability to compete. See **"Item 1A. Risk Factors – Competition within our industry may adversely affect our operations."**

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

Regulation

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

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

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

In August, 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act ("NGA") to make it unlawful for "any entity", including otherwise non-jurisdictional producers such as Stone Energy, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission ("FERC"), in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC's enforcement authority. Stone Energy does not anticipate it will be affected any differently than other producers of natural gas.

In December, 2007, the FERC issued rules requiring that any market participant, including a producer such as Stone Energy, that engages in sales for resale or purchases for resale of natural gas that equal or exceed 2.2 million MMBtus during a calendar year must annually report such sales or purchases to the FERC. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. These rules are subject to pending requests for rehearing; however, if implemented as currently written, the monitoring and reporting required could increase our administrative costs. Stone Energy does not anticipate it will be affected any differently than other producers of natural gas.

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

Environmental Regulation

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

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

The Oil Pollution Act of 1990 (or "OPA") and regulations adopted pursuant to OPA impose a variety of requirements related to the prevention of and response to oil spills into waters of the United States, including the OCS. The OPA subjects owners of oil handling facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages. OPA also requires owners and operators of offshore oil production facilities such as us to establish and maintain evidence of financial responsibility of at least $35 million to cover costs that could be incurred in responding to an oil spill. We believe that we are in substantial compliance with the requirements of OPA, and that these requirements are not any more burdensome to us than they are to other similarly situated oil and gas companies.

In response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth's atmosphere, the current session of the U.S. Congress is considering climate change-related legislation to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman-Warner Climate Security Act or S.2191, would require a 70% reduction in emissions of greenhouse gases from sources within the United States between 2012 and 2050. A vote on this bill by the full Senate is expected to occur before mid-year 2008. In addition, at least 20 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall greenhouse gas emission reduction goal is achieved. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels (e.g., natural gas) we produce. Although we would not be impacted to a greater degree than other similarly situated producers of oil and gas, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the oil and gas we produce.

Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in Massachusetts, et al. v. EPA, the EPA may be required to regulate carbon dioxide and other greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has indicated that it will issue a rulemaking notice to address carbon dioxide and other greenhouse gas emissions from vehicles and automobile fuels, although the date for issuance of this notice has not been finalized. The Court's holding in Massachusetts that greenhouse gases including carbon dioxide fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New federal or state restrictions on emissions of carbon dioxide that may be imposed in areas of the United States in which we conduct business could also adversely affect our cost of doing business and demand for the oil and gas we produce.

We have made, and will continue to make, expenditures in efforts to comply with environmental laws and regulations. While we believe that we are in substantial compliance with applicable environmental laws and regulations in effect and that continued compliance with existing requirements will not have a material adverse impact on us, we also believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards and, thus, we cannot give any assurance that we will not be adversely affected in the future.

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

Employees

On February 11, 2008, we had 224 full time employees. We believe that our relationships with our employees are satisfactory. None of our employees is covered by a collective bargaining agreement. Under our supervision, we utilize the services of independent contractors to perform various daily operational duties.

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

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

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

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and marketing of oil and natural gas. These risks include, but are not limited to:

- commodity price volatility;
- third party interruption of sales to market;
- inflation;
- lack of availability of goods and services;
- environmental risks;
- drilling and other operating risks;
- hurricanes and other weather conditions;
- regulatory changes;
- the uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures; and
- the other risks described in this Form 10-K.

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

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

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

ITEM 1A. 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, cash flows, 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;
- hurricanes and other weather conditions;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- political and economic conditions in oil producing countries, particularly those in the Middle East, Russia, South America and Africa;
- actions by the Organization of Petroleum Exporting Countries ("OPEC");
- 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 may not be able to replace production with new reserves.

In general, the volume of production from oil and gas properties declines as reserves are depleted. The decline rates depend on reservoir characteristics. Gulf of Mexico reservoirs tend to be recovered quickly through production with associated steep declines, while declines in other regions after initial flush production tend to be relatively low. During 2007, 92% of our production was derived from Gulf of Mexico reservoirs, while the remaining portion of our production was derived from the Rocky Mountain Region which was sold in June of 2007. At December 31, 2007, all of our 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 drilling activities. Our future natural gas and oil production is highly dependent upon our level of success in finding or acquiring additional reserves at a unit cost that is sustainable at prevailing commodity prices.

Our actual recovery of reserves may substantially differ from our proved reserve estimates.

This Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir and is therefore inherently imprecise. Additionally, our interpretations of the rules governing the estimation of proved reserves could differ from the interpretation of staff members of regulatory authorities resulting in estimates that could be challenged by these authorities.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this document and the information incorporated by reference. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

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

We spend and will continue to spend a substantial amount of capital for the acquisition, exploration, exploitation, development and production of oil and gas reserves. Our capital expenditures, including acquisitions and exclusive of estimated asset retirement costs, were $200.2 million during 2007, $639.2 million during 2006 and $479.8 million during 2005. We have budgeted total capital expenditures in 2008, excluding property acquisitions, asset retirement costs, hurricane related expenditures and capitalized salaries, general and administrative costs and interest to be approximately $395 million. If low oil and natural gas prices, operating difficulties or other factors, many of which are beyond our control, cause our revenues and cash flows from operating activities to decrease, we may be limited in our ability to fund the capital necessary to complete our capital expenditures program. In addition, if our borrowing base under our credit facility is re-determined to a lower amount, this could adversely affect our ability to fund our planned capital expenditures. After utilizing our available sources of financing, we may be forced to raise additional debt or equity proceeds to fund such capital expenditures. We cannot assure you that additional debt or equity financing will be available or cash flows provided by operations will be sufficient to meet these requirements.

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 February 11, 2008, we had $400 million in outstanding indebtedness. We have a borrowing base under our bank credit facility of $175 million with availability of an additional $122.2 million of borrowings as of February 11, 2008.

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

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

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

- making it more difficult for us to satisfy our obligations under the indentures or other debt and increasing the risk that we may default on our debt obligations;
- requiring us to dedicate a substantial portion of our cash flow from operating activities to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and other general business activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- detracting from our ability to successfully withstand a downturn in our business or the economy generally;
- placing us at a competitive disadvantage against other less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under our credit facility and our senior floating rate notes is at variable rates.

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

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

We have experienced significant shut-ins and losses of production due to the effects of hurricanes in the Gulf of Mexico.

Approximately 92% of our production during 2007 was associated with our Gulf Coast Basin properties. All of our estimated proved reserves at December 31, 2007 were derived from Gulf Coast Basin reservoirs. Accordingly, if the level of production from these properties substantially declines, it could have a material adverse effect on our overall production level and our revenue. We are particularly vulnerable to significant risk from hurricanes and tropical storms. During 2004, we experienced an approximate 7.0 Bcfe deferral of production due to Hurricane Ivan. During 2007, 2006 and 2005, we experienced approximate deferrals of 3.6 Bcfe, 15.6 Bcfe and 16.4 Bcfe of production, respectively, due to Hurricanes Katrina and Rita. We are unable to predict what impact future hurricanes and tropical storms might have on our future results of operations and production.

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

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

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

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

Lower oil and gas prices and other factors 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 the full cost method of accounting, we compare, at the end of each financial reporting period for each cost center, the present value of estimated future net cash flows from proved reserves (based on period-end hedge adjusted commodity prices and excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and gas properties, net of related deferred taxes. We refer to this comparison as a "ceiling test." If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows. We recorded a write-down in 2007 and have recorded write-downs in past years. A write-down of oil and gas properties does not impact cash flow from operating activities, but does reduce net income. The risk that we will be required to write down the carrying value of oil and gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our undeveloped property values, or if estimated future development costs increase. We cannot assure you that we will not experience additional ceiling test write-downs in the future.

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

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

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

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

There are uncertainties in successfully integrating our acquisitions.

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

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

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

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- hurricanes and other weather conditions;
- shortages in experienced labor; and
- shortages or delays in the delivery of equipment.

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

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

Our industry experiences numerous operating risks.

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

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

We maintain insurance of various types to cover our operations, including maritime employer's liability and comprehensive general liability. Coverage amounts are provided by primary liability policies. In addition, we maintain operator's extra expense insurance, which provides coverage for the care, custody and control of wells drilled and/or completed plus re-drill and pollution coverage. The exact amount of coverage for each well is dependent upon its depth and location. We experienced Gulf of Mexico production interruption in 2005, 2006 and 2007 from Hurricanes Katrina and Rita for which we do not have any loss of production insurance.

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

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

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

Competition within our industry may adversely affect our operations.

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

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

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

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

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

Hedging transactions may limit our potential gains or become ineffective.

In order to manage our exposure to price risks in the marketing of our oil and natural gas, we periodically enter into oil and gas price hedging arrangements with respect to a portion of our expected production. Our hedging policy provides that, without prior approval of our board of directors, generally not more than 50% of our estimated production quantities may be hedged. These arrangements may include futures contracts on the New York Mercantile Exchange ("NYMEX"). While intended to reduce the effects of volatile oil and gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected or is shut-in for extended periods due to hurricanes or other factors;
- 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;
- a sudden, unexpected event materially impacts oil or natural gas prices; or
- we are unable to market our production in a manner contemplated when entering into the hedge contract.

We do not pay dividends.

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

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

Certain provisions of our Certificate of Incorporation, Bylaws and shareholders' rights plan and the provisions of the Delaware General Corporation Law may encourage persons considering unsolicited tender offers or other unilateral takeover proposals to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. Our Bylaws currently provide for a classified board of directors, who are elected by plurality voting. The board of directors will propose and recommend that the stockholders approve amending the Bylaws to declassify the board at the next annual meeting. 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. Our board of directors recently considered a policy to elect directors by majority vote, but a decision was made to continue with plurality voting at this time.

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. This shareholder rights agreement expires on September 30, 2008.

Resolution of litigation could materially affect our financial position and results of operations.

We have been named as a defendant in certain lawsuits **(See "Item 3. Legal Proceedings")**. In some of these suits, our liability for potential loss upon resolution may be mitigated by insurance coverage. To the extent that potential exposure to liability is not covered by insurance or insurance coverage is inadequate, we could incur losses that could be material to our financial position or results of operations in future periods.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

As of February 11, 2008, our property portfolio consisted of 48 active properties and 72 primary term leases in the Gulf Coast Basin. We serve as operator on 63% of our active properties. The properties that we operate accounted for 89% of our year-end 2007 estimated proved reserves. This high operating percentage allows us to better control the timing, selection and costs of our drilling and production activities.

Oil and Natural Gas Reserves

The information in this Annual Report on Form 10-K relating to our estimated oil and natural gas proved reserves is based upon reserve reports prepared as of December 31, 2007. Estimates of our proved reserves were prepared by Netherland, Sewell & Associates, Inc.

The following table sets forth our estimated proved oil and natural gas reserves (all of which are located in the Gulf Coast Basin) as of December 31, 2007.

	Proved Developed	Proved Undeveloped	Total Proved	Percent Proved Developed
Oil (MBbls)	25,172	6,414	31,586	80%
Natural gas (MMcf)	171,815	41,268	213,083	81%
Total oil and natural gas (MMcfe)	322,846	79,752	402,598	80%

The following represents additional information on individually significant properties:

Field Name	Location	2007 Production	December 31, 2007 Estimated Proved Reserves	Nature of Interest
Mississippi Canyon Block 109	GOM Shelf	12.8 Bcfe	89.3 Bcfe	Working
Ewing Bank Block 305	GOM Shelf	5.8 Bcfe	64.9 Bcfe	Working
Vermilion Block 255	GOM Shelf	2.7 Bcfe	22.7 Bcfe	Working
South Pelto Block 23	GOM Shelf	3.8 Bcfe	22.2 Bcfe	Working
Main Pass Block 288	GOM Shelf	3.4 Bcfe	21.7 Bcfe	Working
East Cameron Block 64	GOM Shelf	4.2 Bcfe	21.3 Bcfe	Working
South Marsh Island Block 288	GOM Shelf	7.4 Bcfe	10.1 Bcfe	Working

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

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

Acquisition, Production and Drilling Activity

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

	Year Ended December 31,		
	2007	2006	2005
		(In thousands)	
Acquisition costs, net of sales of unevaluated properties	$18,730	$228,108	$138,080
Development costs (1)	154,507	370,201	203,577
Exploratory costs	10,966	160,371	156,472
Sale of Rocky Mountain Region properties	(1,363,939)	-	-
Subtotal	(1,179,736)	758,680	498,129
Capitalized salaries, general and administrative costs and interest, net of fees and reimbursements	36,178	41,543	35,339
Total additions (reductions) to oil and gas properties, net	($1,143,558)	$800,223	$533,468

(1) Includes asset retirement costs of $20,171, $161,048 and $53,687 for the years ended December 31, 2007, 2006 and 2005, respectively.

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, 2007.

	Gross	Net
Productive Wells:		
Oil (1):		
Gulf Coast Basin	145.00	100.09
Rocky Mountain Region	1.00	1.00
Bohai Bay, China	-	-
Appalachia	-	-
	146.00	101.09
Gas (2):		
Gulf Coast Basin	126.00	80.37
Rocky Mountain Region	-	-
Bohai Bay, China	-	-
Appalachia	-	-
	126.00	80.37
Total	272.00	181.46
Developed Acres:		
Gulf Coast Basin	41,734.23	27,790.83
Rocky Mountain Region	-	-
Bohai Bay, China	-	-
Appalachia	-	-
	41,734.23	27,790.83
Undeveloped Acres (3):		
Gulf Coast Basin	608,724.71	405,349.78
Rocky Mountain Region	248,338.10	96,193.00
Bohai Bay, China	-	-
Appalachia	19,691.18	19,625.18
	876,753.99	521,167.96
Total	918,488.22	548,958.79

(1) 13 gross wells each have dual completions.
(2) 8 gross wells each have dual completions.
(3) Leases covering approximately 8.2% of our undeveloped gross acreage will expire in 2008, 10.4% in 2009, 11.2% in 2010, 12.4% in 2011, 5.0% in 2012, 1.3% in both 2013 and 2014, 4.6% in 2015, 2.6% in 2016 and 0.4% and in 2017. Leases covering the remainder of our undeveloped gross acreage (42.6 %) are held by production.

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

	Year Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive	1.00	1.00	6.00	3.49	7.00	6.17
Nonproductive	1.00	1.00	13.00	9.26	8.00	5.17
Development Wells:						
Productive	19.00	12.71	43.00	22.48	37.00	22.42
Nonproductive	1.00	0.33	1.00	0.51	6.00	2.86

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

On April 23, 2007, Stone received notification from the Staff of the SEC that its inquiry into the revision of Stone's proved reserves had been terminated and no enforcement action had been recommended. In 2005, Stone had received notice that the Staff of the SEC was conducting an inquiry into the revision of Stone's proved reserves and the financial statement restatement.

On December 30, 2004, Stone was served with two petitions (civil action numbers 2004-6227 and 2004-6228) filed by the Louisiana Department of Revenue ("LDR") in the 15th Judicial District Court (Parish of Lafayette, Louisiana) claiming additional franchise taxes due. In one case, the LDR is seeking additional franchise taxes from Stone in the amount of $640,000, plus accrued interest of $352,000 (calculated through December 15, 2004), for the franchise year 2001. In the other case, the LDR is seeking additional franchise taxes from Stone (as successor to Basin Exploration, Inc.) in the amount of $274,000, plus accrued interest of $159,000 (calculated through December 15, 2004), for the franchise years 1999, 2000 and 2001. Further, on December 29, 2005, the LDR filed another petition in the 15th Judicial District Court claiming additional franchise taxes due for the taxable years ended December 31, 2002 and 2003 in the amount of $2.6 million plus accrued interest calculated through December 15, 2005 in the amount of $1.2 million. Also, on January 2, 2008, Stone was served with a petition (civil action number 2007-6754) claiming $1.5 million of additional franchise taxes due for the 2004 franchise year, plus accrued interest of $800,000 calculated through November 30, 2007. These assessments all relate to the LDR's assertion that sales of crude oil and natural gas from properties located on the Outer Continental Shelf, which are transported through the state of Louisiana, should be sourced to the state of Louisiana for purposes of computing the Louisiana franchise tax apportionment ratio. The Company disagrees with these contentions and intends to vigorously defend itself against these claims. The franchise tax years 2005, 2006 and 2007 remain subject to examination.

Stone has received an inquiry from the Philadelphia Stock Exchange investigating matters including trading prior to Stone's October 6, 2005 announcement regarding the revision of Stone's proved reserves. Stone cooperated fully with this inquiry. Stone has not received any further inquires form the Philadelphia Exchange since the original request for information.

On or around November 30, 2005, George Porch filed a putative class action in the United States District Court for the Western District of Louisiana (the "Federal Court") against Stone, David Welch, Kenneth Beer, D. Peter Canty and James Prince purporting to allege violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934. Three similar complaints were filed soon thereafter. All complaints had asserted a putative class period commencing on June 17, 2005 and ending on October 6, 2005. All complaints contended that, during the putative class period, defendants, among other things, misstated or failed to disclose (i) that Stone had materially overstated Stone's financial results by overvaluing its oil reserves through improper and aggressive reserve methodologies; (ii) that the Company lacked adequate internal controls and was therefore unable to ascertain its true financial condition; and (iii) that as a result of the foregoing, the values of the Company's proved reserves, assets and future net cash flows were materially overstated at all relevant times. On March 17, 2006, these purported class actions were consolidated, with El Paso Fireman & Policeman's Pension Fund designated as Lead Plaintiff ("Securities Action"). Lead Plaintiff filed a consolidated class action complaint on or about June 14, 2006. The consolidated complaint alleges claims similar to those described above and expands the putative class period to commence on May 2, 2001 and to end on March 10, 2006. On September 13, 2006, Stone and the individual defendants filed motions seeking dismissal of that action.

On August 17, 2007, a Federal Magistrate Judge issued a report and recommendation (the "Report") recommending that the Federal Court grant in part and deny in part the Motions to Dismiss. The Report recommended that (i) the claims asserted against defendants Kenneth Beer and James Prince pursuant to Section 10(b) of the Securities Exchange Act and Rule 10b-5 promulgated thereunder and (ii) claims asserted on behalf of putative class members who sold their Company shares prior to October 6, 2005 be dismissed and that the Motions to Dismiss be denied with respect to the other claims against Stone and the individual defendants.

On October 1, 2007, the Federal Court issued an Order directing that judgment on the Motions to Dismiss be entered in accordance with the recommendations of the Report. On October 23, 2007, Stone and the individual defendants filed a motion seeking permission to appeal the denial of the Motions to Dismiss to the Fifth Circuit Court of Appeals, which motion was denied. The discovery process is now underway. The parties have exchanged initial disclosures and several document requests and interrogatories. Stone has begun producing documents in response to Lead Plaintiff's requests.

In addition, on or about December 16, 2005, Robert Farer and Priscilla Fisk filed respective complaints in the Federal Court purportedly alleging claims derivatively on behalf of Stone. Similar complaints were filed thereafter in the Federal Court by Joint Pension Fund, Local No. 164, I.B.E.W., and in the 15th Judicial District Court, Parish of Lafayette, Louisiana (the "State Court") by Gregory Sakhno. Stone was named as a nominal defendant and David Welch, Kenneth Beer, D. Peter Canty, James Prince, James Stone, John Laborde, Peter Barker, George Christmas, Richard Pattarozzi, David Voelker, Raymond Gary, B.J. Duplantis and Robert Bernhard were named as defendants in these actions. The State Court action purportedly alleged claims of breach of fiduciary duty, abuse of control, gross mismanagement, and waste of corporate assets against all defendants, and claims of unjust enrichment and insider selling against certain individual defendants. The Federal Court derivative actions asserted purported claims against all defendants for breach of fiduciary duty, abuse of control, gross mismanagement, waste of corporate assets and unjust enrichment and claims against certain individual defendants for breach of fiduciary duty and violations of the Sarbanes-Oxley Act of 2002.

On March 30, 2006, the Federal Court entered an order naming Robert Farer, Priscilla Fisk and Joint Pension Fund, Local No. 164, I.B.E.W. as co-lead plaintiffs in the Federal Court derivative action and directed the lead plaintiffs to file a consolidated amended complaint within forty-five days. On April 22, 2006, the complaint in the State Court derivative action was amended to also assert claims on behalf of a purported class of shareholders of Stone. In addition to the above mentioned claims, the amended State Court derivative action complaint purported to allege breaches of fiduciary duty by the director defendants in connection with the then proposed merger transaction with Plains Exploration and Production Company ("Plains") and seeks an order enjoining the director defendants from entering into the then proposed transaction with Plains. On May 15, 2006, the first consolidated complaint in the Federal Court derivative action was filed; it contained a similar injunctive claim. On September 15, 2006, co-lead plaintiffs' in the Federal Court derivative action further amended their complaint to seek an order enjoining Stone's proposed merger with Energy Partners, Ltd. ("EPL") based on substantially the same grounds previously asserted regarding the prior proposed transaction with Plains. On October 2, 2006, each of the defendants in the Federal Court derivative action filed or joined in motions seeking dismissal of all or part of that action. Those motions were denied without prejudice on November 30, 2006 when the Federal Court granted the co-lead plaintiffs leave to file a third amended complaint. Following the filing of the third amended complaint in the Federal Court derivative action, defendants filed motions seeking to have that action either dismissed or stayed until resolution of the pending motion to dismiss the Securities Action before the Federal Court. On December 21, 2006 the Federal Court stayed the Federal Court derivative action at least until resolution of the then-pending motion to dismiss the Securities Action after which time a hearing was to be conducted by the Federal Court to determine the propriety of maintaining that stay. As of the date hereof, the Federal Court has yet to consider any potential modification of the stay.

Stone's Certificate of Incorporation and/or its Restated Bylaws provide, to the extent permissible under the law of Delaware (Stone's state of incorporation), for indemnification of and advancement of defense costs to Stone's current and former directors and officers for potential liabilities related to their service to Stone. Stone has purchased directors and officers insurance policies that, under certain circumstances, may provide coverage to Stone and/or its officers and directors for certain losses resulting from securities-related civil liabilities and/or the satisfaction of indemnification and advancement obligations owed to directors and officers. These insurance policies may not cover all costs and liabilities incurred by Stone and its current and former officers and directors in these regulatory and civil proceedings.

The foregoing pending actions are at an early stage and subject to substantial uncertainties concerning the outcome of material factual and legal issues relating to the litigation and the regulatory proceedings. Accordingly, based on the current status of the litigation and inquiries, we cannot currently predict the manner and timing of the resolution of these matters and are unable to estimate a range of possible losses or any minimum loss from such matters. Furthermore, to the extent that our insurance policies are ultimately available to cover any costs and/or liabilities resulting from these actions, they may not be sufficient to cover all costs and liabilities incurred by us and our current and former officers and directors in these regulatory and civil proceedings.

On or around August 28, 2006, ATS, Inc. instituted an action (the "ATS Litigation") in the Delaware Court of Chancery for New Castle County (the "Delaware Court"). The initial complaint in the ATS Litigation, among other things, challenged certain provisions of the EPL Merger Agreement pursuant to which EPL (i) paid the $43.5 million Plains Termination Fee; and (ii) agreed, under certain contractually specified conditions, to pay Stone $25.6 million in the event of a future termination of the Merger Agreement (the "EPL Termination Fee"). On or around September 12, 2006, a purported shareholder of EPL filed a purported class action in the Delaware Court (the "Farrington Action"). The initial Farrington Action complaint asserted claims similar to those in the ATS Litigation and sought, among other things, a damages recovery in the amount of the Plains Termination Fee.

On or around September 7, 2006, EPL commenced an action against Stone in the Delaware Court (the "Declaratory Action"), in which EPL sought a declaratory judgment with respect to EPL's rights and obligations under Section 6.2(e) of the Merger Agreement. On September 11, 2006, the Delaware Court expedited the Declaratory Action and consolidated with the Declaratory Action a portion of the ATS Litigation in which ATS likewise asserted claims respecting Section 6.2(e) of the Merger Agreement. By oral ruling on September 27, 2006, and subsequent written opinion dated October 11, 2006, the Delaware Court ruled, among other things, that Section 6.2(e) of the Merger Agreement did not limit the ability of EPL to explore and negotiate, in good faith, with respect to any Third Party Acquisition Proposals (as defined in the Merger Agreement), including the tender offer by ATS, Inc. for all of the outstanding shares of EPL stock at $23.00 per share ("ATS Offer"). The Delaware Court dismissed without prejudice the remainder of the claims raised by EPL in the Declaratory Action as not ripe for a judicial determination.

On October 11, 2006, EPL and Stone entered into an agreement (the "Termination and Release Agreement") pursuant to which they agreed, among other things, (i) to enter into a mutual termination of the Merger Agreement, (ii) to mutually release certain actual or potential claims or rights of action, (iii) to mutually seek a dismissal of the Declaratory Action, and (iv) that EPL would make a payment of $8 million to Stone (the "$8 Million Payment"). EPL made the $8 Million Payment to Stone. On October 13, 2006, the Declaratory Action was dismissed by stipulation of the parties and order of the Delaware Court.

On or around October 16, 2006, following the execution of the Termination and Release Agreement, plaintiffs in both the ATS Litigation and the Farrington Litigation sought (and were later granted leave by the Court) to file Second Amended Complaints that, among other things, added claims seeking a recovery in the amount of the $8 Million Payment. On October 26, 2006, ATS voluntarily dismissed the ATS Litigation without prejudice. On November 2, 2006, Stone and EPL filed motions to dismiss the Farrington Action, and on September 10, 2007, the parties filed a Stipulation and Order dismissing the Farrington action without prejudice, which was granted. No compensation in any form passed from any of the defendants to plaintiff or his attorneys. The court retained jurisdiction over plaintiff's claim for award of attorneys' fees and reimbursement of litigation costs and expenses. Plaintiffs have confirmed that they will not be seeking any fees or expenses from Stone in the Farrington Action and, accordingly, Stone is no longer a party to the action.

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

No matters were submitted for a vote of our stockholders during the third or fourth quarters of 2007.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth information regarding the names, ages (as of February 11, 2008) and positions held by each of our executive officers, followed by biographies describing the business experience of our executive officers for at least the past five years. Our executive officers serve at the discretion of the board of directors.

Name	Age	Position
David H. Welch	59	President, Chief Executive Officer and Director
Kenneth H. Beer	50	Senior Vice President and Chief Financial Officer
Andrew L. Gates, III	60	Senior Vice President, General Counsel and Secretary
E. J. Louviere	59	Senior Vice President – Land
J. Kent Pierret	52	Senior Vice President, Chief Accounting Officer and Treasurer
Richard L. Smith	49	Vice President – Exploration and Business Development
Jerome F. Wenzel, Jr.	55	Senior Vice President – Operations/Exploitation
Florence M. Ziegler	47	Vice President – Human Resources and Administration

David H. Welch was appointed President, Chief Executive Officer and a director of the Company effective April 1, 2004. Prior to joining Stone, Mr. Welch served as Senior Vice President of BP America, Inc. since 2003, and Vice President of BP, Inc. since 1999.

Kenneth H. Beer was named Senior Vice President and Chief Financial Officer in August 2005. He most recently served as a director of research and a senior energy analyst at the investment banking firm of Johnson Rice & Company. Prior to joining Johnson Rice in 1992, he spent five years as an energy analyst and investment banker at Howard Weil Incorporated.

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

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

J. Kent Pierret was named Senior Vice President – Chief Accounting Officer and Treasurer in April 2004. Mr. Pierret previously served as Vice President and Chief Accounting Officer since June 1999 and Treasurer since February 2004.

Richard L. Smith was appointed Vice President – Exploration and Business Development in June 2007. Prior to joining Stone, Mr. Smith served as the General Manager of Deepwater Gulf of Mexico Exploration of Dominion E&P Inc. Mr. Smith has also worked for Exxon Corporation and Texaco USA with experience in deep water, shelf, onshore, and international projects.

Jerome F. Wenzel, Jr. joined Stone in October 2004 as Vice President-Production and Drilling and was named Senior Vice President – Operations/Exploitation in September 2005. Prior to joining Stone, Mr. Wenzel held managerial and executive positions with Amoco and BP America, Inc. over a 29 year career.

Florence M. Ziegler was named Vice President – Human Resources and Administration in September 2005. She has been employed by Stone since its inception in 1993 and served as the Director of Human Resources from 1997 to 2004.

PART II

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

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

		High	Low
2006			
	First Quarter	$51.40	$38.55
	Second Quarter	51.50	40.12
	Third Quarter	48.25	39.64
	Fourth Quarter	40.19	34.71
2007			
	First Quarter	$35.35	$26.92
	Second Quarter	35.60	29.03
	Third Quarter	40.43	27.43
	Fourth Quarter	48.53	38.59
2008	First Quarter (through February 11, 2008)	$47.48	$39.14

On February 11, 2008, the last reported sales price on the New York Stock Exchange Composite Tape was $44.03 per share. As of that date, there were 615 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 8¼% Senior Subordinated Notes due 2011 and 6¾% Senior Subordinated Notes due 2014. In addition, our bank credit facility contains provisions that may have the effect of limiting or prohibiting the payment of dividends.

Issuer Purchases of Equity Securities

On September 24, 2007, our Board of Directors authorized a share repurchase program for an aggregate amount of up to $100 million. Through December 31, 2007 no shares had been repurchased under this program; however, shares were withheld from certain employees to pay taxes associated with the employees' vesting of restricted stock. The following table sets forth information regarding our repurchases or acquisitions of common stock during the fourth quarter of 2007:

Period	Total Number of Shares (or Units) Purchased	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet be Purchased Under the Plans or Programs
Share Repurchase Program:				
Oct. 2007	-	$ -	-	
Nov. 2007	-	-	-	
Dec. 2007	-	-	-	
	-	-	-	$100,000,000
Other:				
Oct. 2007	7,541(a)	43.94	-	
Nov. 2007	-	-	-	
Dec. 2007	75(a)	44.75	-	
	7,616	43.95	-	N/A
Total	7,616	$43.95	-	

(a) Amounts include shares withheld from employees upon the vesting of restricted stock in order to satisfy the required tax withholding obligations.

In addition to the above, in the first three quarters of 2007, we repurchased 22,939 shares at an average price of $31.74 per share. These shares were withheld from employees upon the vesting of restricted stock in order to satisfy the required tax withholding obligations.

Equity Compensation Plan Information

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

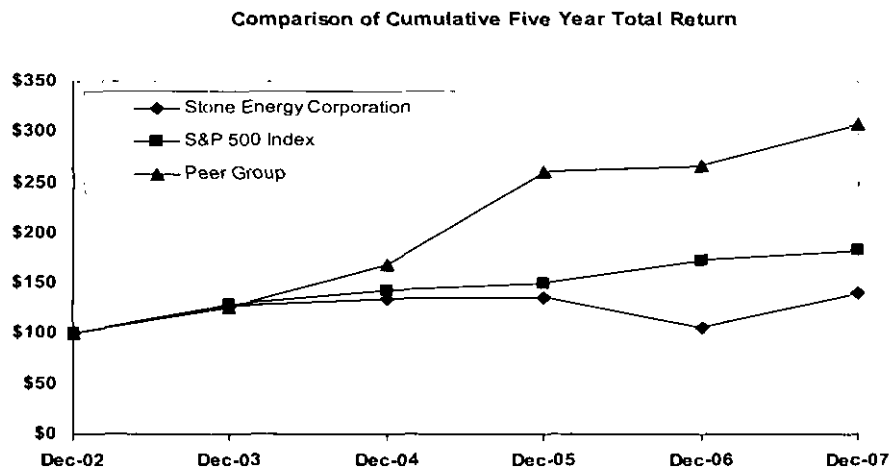
Stock Performance Graph

As required by applicable rules of the Securities and Exchange Commission, the performance graph shown below was prepared based upon the following assumptions:

1. $100 was invested in the Company's Common Stock, the S&P 500 and the Peer Group (as defined below) on December 31, 2002 at $33.36 per share for the Company's Common Stock and at the closing price of the stocks comprising the S&P 500 and the Peer Group, respectively, on such date.

2. Peer Group investment is weighted based upon the market capitalization of each individual company within the Peer Group at the beginning of the period.

3. Dividends are reinvested on the ex-dividend dates.



Measurement Period (Fiscal Year Covered)	SGY	Peer Group	S&P 500
12/31/03	127.25	125.42	128.68
12/31/04	135.16	168.11	142.69
12/31/05	136.48	261.21	149.70
12/31/06	105.97	266.83	173.34
12/31/07	140.62	307.42	182.86

The companies that comprised our Peer Group in 2007 are as follows: Bois D'Arc Energy, Cabot Oil & Gas Corporation, Callon Petroleum Company, Comstock Resources, Inc., Energy Partners, Ltd., Forest Oil Corporation, Newfield Exploration Company, St. Mary Land and Exploration Company, Swift Energy Company, and W&T Offshore, Inc. The Houston Exploration Company was removed from our Peer Group pursuant to a merger with Forest Oil Corporation during 2007.

The information in this Form 10-K appearing under the heading "Stock Performance Graph" is being "furnished" pursuant to Item 2.01(e) of Regulation S-K under the Securities Act of 1933, as amended, and shall not be deemed to be "soliciting material" or "filed" with the Securities and Exchange Commission or subject to Regulation 14A or 14C, other than as provided in Item 2.01(e) of Regulation S-K, or to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended.

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, 2007. 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,				
	2007	2006	2005	2004	2003
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenue:					
Oil production	$424,205	$348,979	$244,469	$214,153	$174,139
Gas production	329,047	337,321	391,771	330,048	334,166
Derivative income, net	-	2,688	-	-	-
Total operating revenue	753,252	688,988	636,240	544,201	508,305
Operating expenses:					
Lease operating expenses	149,702	159,043	114,664	100,045	72,786
Production taxes	9,945	13,472	13,179	7,408	5,975
Depreciation, depletion and amortization	302,739	320,696	241,426	210,861	188,813
Write-down of oil and gas properties	8,164	510,013	-	-	-
Accretion expense	17,620	12,391	7,159	5,852	6,292
Derivative expenses, net	666	-	3,388	4,099	8,711
Salaries, general and administrative expenses	33,584	34,266	22,705	14,311	14,870
Incentive compensation expense	5,117	4,356	1,252	2,318	2,636
Total operating expenses	527,537	1,054,237	403,773	344,894	300,083
Gain on Rocky Mountain Region properties divestiture	59,825	-	-	-	-
Income (loss) from operations	285,540	(365,249)	232,467	199,307	208,222
Other (income) expenses:					
Interest expense	32,068	35,931	23,151	16,835	19,860
Interest income	(12,135)	(2,524)	(1,095)	(208)	(219)
Early extinguishment of debt	844	-	-	845	4,661
Merger expenses	-	50,029	-	-	-
Merger expense reimbursement	-	(51,500)	-	-	-
Other income, net	(5,657)	(4,657)	(2,799)	(2,269)	(2,376)
Total other expenses, net	15,120	27,279	19,257	15,203	21,926
Income (loss) before income taxes	270,420	(392,528)	213,210	184,104	186,296
Income tax provision (benefit)	88,984	(138,306)	76,446	64,436	65,203
Income (loss) before cumulative effects of accounting changes, net of tax	181,436	(254,222)	136,764	119,668	121,093
Cumulative effects of accounting changes, net of tax (1)	-	-	-	-	2,099
Net income (loss)	$181,436	($254,222)	$136,764	$119,668	$123,192
Earnings and dividends per common share:					
Income (loss) before cumulative effects of accounting changes per share	$6.57	($9.29)	$5.07	$4.50	$4.60
Earnings (loss) per common share	$6.57	($9.29)	$5.07	$4.50	$4.67
Income (loss) before cumulative effects of accounting changes per share assuming dilution	$6.54	($9.29)	$5.02	$4.45	$4.56
Earnings (loss) per common share assuming dilution	$6.54	($9.29)	$5.02	$4.45	$4.64
Cash dividends declared	-	-	-	-	-
Cash Flow Data:					
Net cash provided by operating activities	$465,158	$399,035	$461,213	$369,668	$390,811
Net cash provided by (used in) investing activities	344,812	(660,456)	(499,932)	(475,159)	(341,180)
Net cash provided by (used in) financing activities	(393,706)	240,575	94,170	112,648	(60,140)
Balance Sheet Data (at end of period):					
Working capital (deficit)	$412,445	$1,845	$16,506	($28,598)	($38,474)
Oil and gas properties, net	1,181,312	1,784,425	1,810,959	1,517,308	1,216,141
Total assets	1,889,603	2,128,471	2,140,317	1,695,664	1,332,485
Long-term debt, less current portion	400,000	797,000	563,000	482,000	370,000
Stockholders' equity	885,802	711,640	944,123	772,934	644,111

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

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF 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, 2007. 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 – Note 1."**

Executive Overview

We are an independent oil and natural gas company engaged in the acquisition, exploration, exploitation, development and operation of oil and gas properties located primarily in the Gulf of Mexico (the "GOM"). Prior to June 29, 2007, we also had significant operations in the Rocky Mountain Basins and the Williston Basin (Rocky Mountain Region). We are also engaged in an exploratory joint venture in Bohai Bay, China. Our business strategy is to increase reserves, production and cash flow through the acquisition, exploitation and development of mature properties in the Gulf Coast Basin and exploring opportunities in the deep water environment of the Gulf of Mexico, Rocky Mountain Region, Appalachia, Bohai Bay, China and other potential areas. See **"Item 1. Business – Strategy and Operational Overview."**

2007 Significant Events.

- *Property Divestiture* – On June 29, 2007, we completed the sale of substantially all of our Rocky Mountain Region properties and related assets to Newfield Exploration Company for a total consideration of $582 million. At December 31, 2006, the estimated proved reserves associated with these assets totaled 182.4 Bcfe, which represented 31% of our estimated proved oil and gas reserves. A portion of the proceeds was used to pay down all outstanding borrowings under our bank credit facility and to fund the redemption of our Senior Floating Rate Notes.

- *Stock Repurchase Plan* – In September of 2007, we announced that our Board of Directors had approved a share repurchase program for an aggregate amount of up to $100 million. Although no shares were repurchased through December 31, 2007, we continue to view share repurchases as an investment alternative.

- *Credit Facility* – In November of 2007, we entered into a new $300 million credit facility maturing on July 1, 2011.

2008 Outlook.

GOM Divestitures – In early 2008, we completed a small divestiture of non-core Gulf Coast Basin properties. The aggregate proceeds from these divestitures were approximately $20 million before closing adjustments. Year-end 2007 reserves associated with these properties totaled 18 Bcfe and projected 2008 production was 9 MMcfe per day.

Exploratory Drilling – During 2008, we expect a greater percentage of our capital expenditures budget will be allocated to exploratory drilling versus 2007 including the likely drilling of exploratory plays in Bohai Bay, Appalachia and in the deep water of the GOM.

Our 2008 capital expenditures budget is approximately $395 million (exclusive of $25 million in budgeted abandonment expenditures) excluding acquisitions, hurricane related expenditures and capitalized interest and general and administrative expenses. The $395 million is expected to be spent as follows:

GOM exploitation program	51%
GOM facilities	9%
GOM exploration, leasing and seismic	33%
Rocky Mountain, Appalachia, Bohai Bay, other	7%

Known Trends and Uncertainties.

Gulf Coast Basin Reserve Replacement – We have faced challenges in replacing production in the Gulf Coast Basin at a reasonable unit cost. This condition has been caused by a number of factors including the following:

- rising costs of drilling, abandonment and production services;
- lack of an adequate inventory of reserve targets of an attractive size; and
- inadequate risking of projects to assist in appropriate portfolio management.

During 2005 and early 2006, we instituted organizational changes which have lead to a replenishment of our prospect inventory. Additionally, we have employed a new risk management system for project evaluation that we believe will result in more efficient portfolio management. Our 2007 Gulf Coast conventional shelf exploitation program reflected the results of our organizational and risk management changes and resulted in an improvement in performance and a resulting decrease in unit costs.

In 2008, we expect a higher percentage of our capital expenditures to be on exploratory prospects. Because exploratory prospects tend to involve lower probabilities of geological success but higher potential reserves, it is difficult to predict the effect of this shift on reserve replacement and finding costs.

Louisiana Franchise Taxes – We have been involved in litigation with the state of Louisiana over the proper computation of franchise taxes allocable to the state. This litigation relates to the state's position that sales of crude oil and natural gas from properties located on the Outer Continental Shelf, which are transported through the state of Louisiana, should be sourced to Louisiana for purposes of computing franchise taxes. We disagree with the state's position. However, if the state's position were to be upheld, we would incur higher franchise tax expense in future years. See **"Item 3. Legal Proceedings."**

Hurricanes – Since the majority of our production originates in the Gulf of Mexico, we are particularly vulnerable to the effects of hurricanes on production. In 2007, 2006 and 2005, we experienced deferrals of production due to Hurricanes Katrina, Rita and Ivan of approximately 3.6 Bcfe, 15.6 Bcfe and 16.4 Bcfe, respectively. Although we do include hurricane contingencies in our production forecasting models, hurricane activity can be more frequent and disruptive than what is projected as was the case in 2005.

Regulatory Inquiries and Stockholder Lawsuits – We have been named as a defendant in certain stockholder lawsuits resulting from our reserve restatement. The ultimate resolution of these matters and their impact on us is uncertain. See **"Item 3. Legal Proceedings."**

International Operations – Included in unevaluated oil and gas property costs at December 31, 2007 are $29.6 million of capital expenditures related to our properties in Bohai Bay, China. Under full cost accounting, investments in individual countries represent separate cost centers for computation of depreciation, depletion and amortization as well as for full cost ceiling test evaluations. In 2007 this investment was deemed to be impaired in the amount of $8.2 million. Given that this is our sole investment in the Peoples Republic of China, it is possible that future evaluations of this project could result in additional charges to income on our income statement.

Current Income Taxes – The sale of substantially all of our Rocky Mountain Region properties resulted in a significant taxable gain, causing us to utilize the entirety of our net operating loss and statutory depletion carry forwards. Despite the utilization of these benefits, we estimate that we have incurred a current tax liability of approximately $95.6 million for the 2007 tax year. For 2008, we have no net operating loss or depletion carry forwards available to apply against potential taxable events. The prediction of current tax liabilities is difficult in the exploration and production industry because of its sensitivity to production, commodity prices, dry hole and intangible drilling costs and other factors.

Liquidity and Capital Resources

Cash Flow and Working Capital. Net cash flow provided by operating activities totaled $465.2 million during 2007 compared to $399.0 million and $461.2 million in 2006 and 2005, respectively. Based on our outlook of commodity prices and our estimated production, we expect to fund our 2008 capital expenditures with cash flow provided by operating activities.

Net cash flow provided by investing activities totaled $344.8 million during the year ended December 31, 2007, which primarily represents proceeds received from the sale of substantially all of our Rocky Mountain Region properties offset by our investment in oil and natural gas properties. Net cash flow used in investing activities totaled $660.5 million and $499.9 million during 2006 and 2005, respectively, which primarily represents our investment in oil and natural gas properties.

Net cash flow used in financing activities totaled $393.7 million during the year ended December 31, 2007, which primarily represents the redemption of our senior floating rate notes and repayments of borrowings under our credit facility. Net cash flow provided by financing activities totaled $240.6 million and $94.2 million for the years ended December 31, 2006 and 2005, respectively. Net cash flow provided by financing activities generated during 2006 primarily represents proceeds from the issuance of our Senior Floating Rate Notes due 2010, borrowings net of repayments under our bank credit facility and proceeds from the exercise of stock options. Net cash flow provided by financing activities generated during 2005 primarily relates to borrowings net of repayments under our bank credit facility and proceeds from the exercise of stock options.

We had working capital at December 31, 2007 of $412.4 million. A substantial portion of this working capital was generated from the sale of our Rocky Mountain Region properties on June 29, 2007. We believe that our working capital balance should be viewed in conjunction with availability of borrowings under our bank credit facility when measuring liquidity. "Liquidity" is defined as the ability to obtain cash quickly either through the conversion of assets or incurrence of liabilities. See "***Bank Credit Facility.***"

Our 2008 capital expenditures budget, excluding acquisitions, asset retirement costs, hurricane related expenditures, capitalized interest and general and administrative expenses, is approximately $395 million, or 170% higher than our 2007 capital expenditures, excluding acquisitions, asset retirement costs and capitalized interest and general and administrative expenses. Based on our outlook of commodity prices and our estimated production, we expect to fund our 2008 capital program with cash flow provided by operating activities.

To the extent that 2008 cash flow from operating activities exceeds our estimated 2008 capital expenditures, we may pay down a portion of our existing debt or repurchase shares of common stock. If cash flow from operating activities during 2008 is not sufficient to fund estimated 2008 capital expenditures, we believe that our bank credit facility will provide us with adequate liquidity. See "***Bank Credit Facility.***"

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

Bank Credit Facility. At December 31, 2007, we had no outstanding borrowings under our bank credit facility and letters of credit totaling $52.8 million had been issued pursuant to the facility. Effective June 29, 2007, in connection with the sale of substantially all of our Rocky Mountain Region properties, our borrowing base under the credit facility was reduced from $250 million to $85.4 million. On November 1, 2007, we entered into a $300 million senior secured credit facility, maturing July 1, 2011, with a syndicated bank group. The new facility has an initial borrowing base of $175 million and replaces the previous $500 million credit facility. We recorded a pre-tax charge in the fourth quarter of 2007 in the amount of $0.2 million for the early extinguishment of debt of the old facility. As of February 11, 2008, after accounting for the $52.8 million of letters of credit, we have $122.2 million of borrowings available under the new credit facility. The borrowing base under the credit facility is re-determined periodically based on the bank group's evaluation of our proved oil and gas reserves.

Under the financial covenants of our new credit facility, we must (i) maintain a ratio of consolidated debt to consolidated EBITDA, as defined in the credit agreement, for the preceding four quarterly periods of not greater than 3.25 to 1 and (ii) maintain a ratio of EBITDA to consolidated Net Interest, as defined in the credit agreement, for the preceding four quarterly periods of not less than 3.0 to 1.0. As of December 31, 2007 our debt to EBITDA Ratio was 0.7 to 1 and our EBITDA to consolidated Net Interest Ratio was approximately 27.5 to 1. In addition, the new credit facility places certain customary restrictions or requirements with respect to disposition of properties, incurrence of additional debt, change of ownership and reporting responsibilities. These covenants may limit or prohibit us from paying cash dividends but do allow for limited stock repurchases.

$225 Million Senior Floating Rate Notes. On August 1, 2007, we redeemed our Senior Floating Rate Notes at their face value of $225 million. We recorded a pre-tax charge of $0.6 million in the third quarter of 2007 for the early extinguishment of debt.

Share Repurchase Program. On September 24, 2007, our Board of Directors authorized a share repurchase program for an aggregate amount of up to $100 million. The shares may be repurchased from time to time in the open market or through privately negotiated transactions. The repurchase program is subject to business and market conditions, and may be suspended or discontinued at any time. Through December 31, 2007, no shares had been repurchased.

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

Contractual Obligations and Other Commitments

The following table summarizes our significant contractual obligations and commitments, other than hedging contracts, by maturity as of December 31, 2007 (in thousands):

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Contractual Obligations and Commitments:					
8¼% Senior Subordinated Notes due 2011	$200,000	$ -	$ -	$200,000	$ -
6¾% Senior Subordinated Notes due 2014	200,000	-	-	-	200,000
Interest and commitment fees (1)	160,855	30,511	60,929	43,007	26,408
Asset retirement obligations including accretion	523,467	44,476	46,017	94,688	338,286
Rig commitments	17,815	17,815	-	-	-
Seismic data commitments (2)	16,336	16,336	-	-	-
Operating lease obligations	865	307	558	-	-
Total Contractual Obligations and Commitments	$1,119,338	$109,445	$107,504	$337,695	$564,694

(1) Represents interest on notes and commitment fees on unused line of bank credit facility. See ***Bank Credit Facility*** above.
(2) Represents pre-commitments for seismic data purchases.

Results of Operations

2007 Compared to 2006. 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 Natural Gas Reserves."**

	Year Ended December 31,			
	2007	2006	Variance	% Change
Production:				
Oil (MBbls)	6,088	5,593	495	9%
Natural gas (MMcf)	45,088	43,508	1,580	4%
Oil and natural gas (MMcfe)	81,617	77,066	4,551	6%
Average prices: (1)				
Oil (per Bbl)	$69.68	$62.40	$7.28	12%
Natural gas (per Mcf)	7.30	7.75	(0.45)	(6%)
Oil and natural gas (per Mcfe)	9.23	8.91	0.32	4%
Expenses (per Mcfe):				
Lease operating expenses	$1.83	$2.06	($0.23)	(11%)
Salaries, general and administrative expenses (2)	0.41	0.44	(0.03)	(7%)
DD&A expense on oil and gas properties	3.67	4.11	(0.44)	(11%)
Estimated Proved Reserves at December 31:				
Oil (MBbls)	31,586	41,360	(9,774)	(24%)
Natural gas (MMcf)	213,083	342,782	(129,699)	(38%)
Oil and natural gas (MMcfe)	402,598	590,942	(188,344)	(32%)

(1) Includes the settlement of effective hedging contracts.
(2) Exclusive of incentive compensation expense.

For the year ended 2007, net income totaled $181.4 million, or $6.54 per share, compared to a net loss for the year ended December 31, 2006 of $254.2 million, or $9.29 per share. All per share amounts are on a diluted basis.

Included in 2007 net income before income taxes is a $59.8 million gain on the sale of our Rocky Mountain Region properties, representing the excess of the proceeds from the sale over the carrying value of the oil and gas properties and other assets sold and transaction costs.

We follow the full cost method of accounting for oil and gas properties. At the end of 2007 and 2006, we recognized ceiling test write-downs of our oil and gas properties totaling $8.2 million ($5.5 million after taxes) and $510.0 million ($330.5 million after taxes), respectively. The write-downs did not impact our cash flow from operations but did reduce net income and stockholders' equity.

Included in the 2006 net loss is $51.5 million in merger expense reimbursements partially offset by $50.0 million in merger related expenses. Merger expenses include a $43.5 million termination fee incurred in connection with the proposed merger with Energy Partners Ltd. ("EPL"). Prior to entering into the EPL merger agreement, we terminated our merger agreement with Plains Exploration and Production Company ("Plains") and Plains Acquisition Corp. ("Plains Acquisition") on June 22, 2006. As required under the terms of the terminated merger agreement among Stone, Plains and Plains Acquisition, Plains was entitled to a termination fee of $43.5 million ("Plains Termination Fee"), which was advanced by EPL to Plains on June 22, 2006. Pursuant to the EPL merger agreement, we were obligated to repay all or a portion of this termination fee under certain circumstances if the EPL merger was not consummated. The $43.5 million termination fee was recorded as merger expenses in the income statement during the second quarter of 2006. Of this amount, $25.3 million was potentially reimbursable to EPL under certain circumstances described in the EPL merger agreement and therefore was recorded as deferred revenue on the balance sheet as of June 30, 2006 and September 30, 2006. The remaining $18.2 million of the termination fee was recorded as merger expense reimbursement in the income statement during the three months ended June 30, 2006. On October 11, 2006, we entered into an agreement with EPL pursuant to which the EPL merger agreement was terminated. Pursuant to the termination of the EPL merger agreement, EPL paid us $8 million and released all claims to the $43.5 million Plains Termination Fee. The $8.0 million fee paid to us by EPL in conjunction with the termination of the EPL merger agreement was recorded as merger expense reimbursement in earnings in the fourth quarter of 2006. Additionally, the remaining $25.3 million of the Plains Termination Fee was recognized as merger expense reimbursement in earnings in the fourth quarter of 2006.

The variance in annual results was also due to the following components:

Production. 2007 production totaled 6,088,000 barrels of oil and 45.1 Bcf of natural gas compared to 5,593,000 barrels of oil and 43.5 Bcf of natural gas produced during 2006, a increase on a gas equivalent basis of 4.6 Bcfe. 2007 and 2006 total production rates were negatively impacted by extended Gulf Coast shut-ins due to Hurricanes Katrina and Rita, amounting to volumes of approximately 3.6 Bcfe (10 MMcfe per day) and 15.6 Bcfe (43MMcfe per day), respectively. Without the effects of the hurricane production deferrals, year to year total production volumes decreased approximately 7.5 Bcfe. The decrease was primarily the result of the sale of substantially all of our Rocky Mountain Region properties on June 29, 2007. Rocky Mountain Region production was 11.9 Bcfe for the year ended December 31, 2006 and 6.6 Bcfe for the year ended December 31, 2007.

Prices. Prices realized during 2007 averaged $69.68 per barrel of oil and $7.30 per Mcf of natural gas compared to 2006 average realized prices of $62.40 per barrel of oil and $7.75 per Mcf of natural gas. On a gas equivalent basis, average 2007 prices were 4% higher than prices realized during 2006. All unit pricing amounts include the settlement of effective hedging contracts.

We enter into various hedging contracts in order to reduce our exposure to the possibility of declining oil and gas prices. During the years ended December 31, 2007 and 2006, our effective hedging transactions increased our average realized natural gas prices by $0.23 per Mcf and $0.85 per Mcf, respectively. Average realized oil prices were decreased during the year ended December 31, 2007 by $0.42 per barrel and were increased by $0.02 per barrel for year ended December 31, 2006.

Income. As a result of 4% higher realized prices on a gas equivalent basis and a 6% increase in production volumes for the year , oil and natural gas revenue increased 10% to $753.3 million in 2007 from $686.3 million during 2006. Rocky Mountain Region year ended December 31, 2007 oil and natural gas revenue amounted to $47.4 million, representing 6% of total company oil and natural gas revenue for such period.

Interest income totaled $12.1 million during 2007 compared to $2.5 million during 2006. The increase in interest income is the result of an increase in our cash balances during the period after the sale of substantially all of our Rocky Mountain Region properties in June 2007.

Derivative Income/Expense. During 2007 and 2006, certain of our derivative contracts were determined to be partially ineffective because of differences in the relationship between the fixed price in the derivative contract and actual prices realized. Derivative expense for the year ended December 31, 2007 totaled $0.7 million, representing changes in the fair market value of the ineffective portion of the derivatives. Derivative income for the year ended December 31, 2006 totaled $2.7 million, consisting of $2.3 million of cash settlements on the ineffective portion of derivatives and $0.4 million of changes in the fair market value of the ineffective portion of derivatives.

Expenses. During 2007, we incurred lease operating expenses of $149.7 million, compared to $159.0 million incurred during 2006. On a unit of production basis, 2007 lease operating expenses were $1.83 per Mcfe as compared to $2.06 per Mcfe for 2006. The decrease in lease operating expenses is primarily the result of a decrease in major maintenance activity in 2007, net of estimated insurance recoveries. We sold substantially all of our Rocky Mountain Region properties in June 2007. Rocky Mountain Region lease operating expenses were $10.0 million and $10.6 million for the years ended December 31, 2007 and 2006, respectively.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2007 totaled $299.2 million, or $3.67 per Mcfe, compared to DD&A expense of $316.8 million, or $4.11 per Mcfe in 2006. At December 31, 2006, we recorded a ceiling test write-down, which reduced our net investment in oil and gas properties and resulted in a reduction of the going forward unit cost of DD&A of $0.86 per Mcfe. See **"Known Trends and Uncertainties."**

During 2007 and 2006, salaries, general and administrative ("SG&A") expenses (exclusive of incentive compensation) totaled $33.6 million and $34.3 million, respectively. Included in 2007 SG&A are severance and retention payments of $2.1 million made to employees in our Denver District in connection with the sale of substantially all of our Rocky Mountain Region properties in June 2007 and the resulting discontinuation of operations of such district. Total 2007 SG&A expenses for the Denver District were $3.8 million. Exclusive of the $2.1 million severance and retention payments, 2007 Denver District SG&A represented 5.5% of total company SG&A.

Interest expense for 2007 totaled $32.1 million, net of $16.2 million of capitalized interest, compared to interest of $35.9 million, net of $18.2 million of capitalized interest, during 2006. In June 2007, a portion of the proceeds from the sale of substantially all of our Rocky Mountain Region properties was used to pay down all outstanding borrowings under our bank credit facility resulting in a decrease in interest expense for the year ended December 31, 2007.

During 2007 and 2006, we incurred $17.6 million and $12.4 million, respectively, of accretion expense related to asset retirement obligations. The increase in 2007 accretion expense is due to increases in estimated asset retirement costs determined in late 2006.

For the years ended December 31, 2007 and 2006, production taxes totaled $9.9 million and $13.5 million, respectively. The decrease in production taxes resulted from the sale of substantially all of our Rocky Mountain Region properties in June 2007. 2007 Rocky Mountain Region production taxes totaled $4.0 million, representing 40% of total company production taxes for such period.

We estimate that we have incurred $95.6 million of current federal and state income tax expense for calendar year 2007 of which $57.6 million is unpaid through December 31, 2007.

Reserves. At December 31, 2007, our estimated proved oil and gas reserves totaled 402.6 Bcfe, compared to December 31, 2006 reserves of 590.9 Bcfe. The decrease in estimated proved reserves during 2007 was primarily the result of the sale of substantially all of our Rocky Mountain Region properties in June 2007. Estimated proved natural gas reserves totaled 213.1 Bcf and estimated proved oil reserves totaled 31.6 MMBbls at the end of 2007. The reserve estimates at December 31, 2007 were prepared by an engineering firm in accordance with guidelines established by the SEC.

Our standardized measure of discounted future net cash flows was $1.5 billion and $1.2 billion at December 31, 2007 and 2006, respectively. You should not assume that these estimates of future net cash flows represent the fair value of our estimated oil and natural gas reserves. As required by the SEC, we determine these estimates of future net cash flows using market prices for oil and gas on the last day of the fiscal period. The average year-end oil and gas prices net of differentials on all of our properties used in determining these amounts, excluding the effects of hedges in place at year-end, were $94.72 per barrel and $7.25 per Mcf for 2007 and $56.90 per barrel and $5.39 per Mcf for 2006.

2006 Compared to 2005. 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 Natural Gas Reserves."**

	Year Ended December 31,			
	2006	**2005**	**Variance**	**% Change**
Production:				
Oil (MBbls)	5,593	4,838	755	16%
Natural gas (MMcf)	43,508	54,129	(10,621)	(20%)
Oil and natural gas (MMcfe)	77,066	83,158	(6,092)	(7%)
Average prices: (1)				
Oil (per Bbl)	$62.40	$50.53	$11.87	24%
Natural gas (per Mcf)	7.75	7.24	0.51	7%
Oil and natural gas (per Mcfe)	8.91	7.65	1.26	17%
Expenses (per Mcfe):				
Lease operating expenses	$2.06	$1.38	$0.68	49%
Salaries, general and administrative expenses (2)	0.44	0.27	0.17	63%
DD&A expense on oil and gas properties	4.11	2.87	1.24	43%
Estimated Proved Reserves at December 31:				
Oil (MBbls)	41,360	41,509	(149)	(0.4%)
Natural gas (MMcf)	342,782	344,088	(1,306)	(0.4%)
Oil and natural gas (MMcfe)	590,942	593,142	(2,200)	(0.4%)

(1) Includes the settlement of effective hedging contracts.
(2) Exclusive of incentive compensation expense.

For the year ended 2006, we reported a net loss totaling $254.2 million, or $9.29 per share, compared to net income for the year ended December 31, 2005 of $136.8 million, or $5.02 per share. All per share amounts are on a diluted basis.

We follow the full cost method of accounting for oil and gas properties. At the end of 2006, we recognized a ceiling test write-down of our oil and gas properties totaling $510.0 million, or $330.5 million after taxes. This expense did not impact our cash flow from operations but did reduce net income and stockholders' equity.

Included in the 2006 net loss is $51.5 million in merger expense reimbursements partially offset by $50.0 million in merger related expenses. Merger expenses include a $43.5 million termination fee incurred in connection with the proposed merger with EPL. Prior to entering into the EPL merger agreement, we terminated our merger agreement with Plains and Plains Acquisition on June 22, 2006. As required under the terms of the terminated merger agreement among Stone, Plains and Plains Acquisition, Plains was entitled to a termination fee of $43.5 million, which was advanced by EPL to Plains on June 22, 2006. Pursuant to the EPL merger agreement, we were obligated to repay all or a portion of this termination fee under certain circumstances if the EPL merger was not consummated. The $43.5 million termination fee was recorded as merger expenses in the income statement during the second quarter of 2006. Of this amount, $25.3 million was potentially reimbursable to EPL under certain circumstances described in the EPL merger agreement and therefore was recorded as deferred revenue on the balance sheet as of June 30, 2006 and September 30, 2006. The remaining $18.2 million of the termination fee was recorded as merger expense reimbursement in the income statement during the three months ended June 30, 2006.

On October 11, 2006, we entered into an agreement with EPL pursuant to which the EPL merger agreement was terminated. Pursuant to the termination of the EPL merger agreement, EPL paid us $8 million and released all claims to the $43.5 million Plains Termination Fee. The $8.0 million fee paid to us by EPL in conjunction with the termination of the EPL merger agreement was recorded as merger expense reimbursement in earnings in the fourth quarter of 2006. Additionally, the remaining $25.3 million of the Plains Termination Fee was recognized as merger expense reimbursement in earnings in the fourth quarter of 2006.

The variance in annual results was also due to the following components:

Production. 2006 production totaled 5,593,000 barrels of oil and 43.5 Bcf of natural gas compared to 4,838,000 barrels of oil and 54.1 Bcf of natural gas produced during 2005, a decrease on a gas equivalent basis of 6.1 Bcfe. 2006 total production rates were negatively impacted by extended Gulf Coast shut-ins due to Hurricanes Katrina and Rita, amounting to volumes of approximately 15.6 Bcfe, or 43MMcfe per day, while 2005 production rates reflected shut-ins due to Hurricanes Katrina and Rita, amounting to volumes of approximately 16.4 Bcfe, or 45 MMcfe per day. Without the effects of the hurricane production deferrals, year to year total production volumes decreased approximately 6.9 Bcfe, as a result of natural production declines.

Approximately 85% of our 2006 production volumes were generated from our Gulf Coast Basin properties while the remaining 15% came from our Rocky Mountain Region properties.

Prices. Prices realized during 2006 averaged $62.40 per barrel of oil and $7.75 per Mcf of natural gas compared to 2005 average realized prices of $50.53 per barrel of oil and $7.24 per Mcf of natural gas. On a gas equivalent basis, average 2006 prices were 17% higher than prices realized during 2005. All unit pricing amounts include the settlement of effective hedging contracts.

We enter into various hedging contracts in order to reduce our exposure to the possibility of declining oil and gas prices. During the year ended December 31, 2006, we realized a net increase in average realized natural gas prices related to our effective zero-premium collars of $0.85 per Mcf and a net increase in average realized oil prices of $0.02 per barrel. We realized a net decrease of $0.58 per Mcf in average realized natural gas prices related to our effective swaps and a net decrease of $2.26 per Bbl in average realized oil prices related to our effective zero-premium collars for the year ended December 31, 2005.

Income. As a result of 17% higher realized prices on a gas equivalent basis, oil and natural gas revenue increased 8% to $686.3 million in 2006 from $636.2 million during 2005 despite a 7% decline in total production volumes during 2006.

Derivative Income/Expense. During 2006, certain of our derivative contracts were determined to be partially ineffective because of differences in the relationship between the fixed price in the derivative contract and actual prices realized. Derivative income for the year ended December 31, 2006 totaled $2.7 million, consisting of $2.3 million of cash settlements on the ineffective portion of derivatives and $0.4 million of changes in the fair market value of the ineffective portion of derivatives.

As a result of extended shut-ins of production after Hurricane Katrina and Hurricane Rita, our September, October and November 2005 crude oil production levels were below the volumes that were hedged. Consequently, one of our crude oil hedges for the months of September, October and November 2005 was deemed to be ineffective. During 2005, we recognized $3.4 million of derivative expenses, which related to the cash settlement of the ineffective crude oil collars.

Expenses. During 2006, we incurred lease operating expenses of $159.0 million, compared to $114.7 million incurred during 2005. On a unit of production basis, 2006 lease operating expenses were $2.06 per Mcfe as compared to $1.38 per Mcfe for 2005. 2006 lease operating costs included an approximate $19 million increase in property and control-of-well insurance premiums and $24 million of repairs in excess of estimated insurance recoveries related to damage from Hurricanes Katrina, Rita and Ivan and increased major maintenance repair activity.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2006 totaled $316.8 million, or $4.11 per Mcfe, compared to DD&A expense of $238.3 million, or $2.87 per Mcfe in 2005. The increase in 2006 DD&A on a unit basis is attributable to the unit cost of current year net reserve additions (including future development costs) exceeding the per unit amortizable base as of the beginning of the year. See **"Known Trends and Uncertainties."**

During 2006 and 2005, salaries, general and administrative ("SG&A") expenses totaled $34.3 million and $22.7 million, respectively. The increase in SG&A is primarily due to approximately $3.7 million of additional compensation expense associated with restricted stock issuances and stock option expensing, an approximate $2.5 million increase in legal and consulting fees and a $2.6 million increase in salaries and wages expense resulting from salary adjustments.

Incentive compensation expense for 2006 totaled $4.4 million compared to $1.3 million for 2005. The increase in incentive compensation expense is due to an employee retention program put in place by the board of directors in the third quarter of 2006 whereby employees earned bonuses equal to 100% of their targeted bonus opportunity in 2006.

During 2006 and 2005, we incurred $12.4 million and $7.2 million, respectively, of accretion expense related to asset retirement obligations. The increase in 2006 accretion expense is due to higher estimated asset retirement costs. We had approximately $10.3 million of additional asset retirement costs related to asset additions in 2006, $6.5 million of which relates to the acquisition of additional working interests in Mississippi Canyon Blocks 109 and 108.

The approximate $169.3 million revision in estimates of asset retirement obligations in 2006 is due to the following factors: (1) approximately $142.0 million of the increase is due to a significant increase in 2006 in the cost of services necessary to abandon oil and gas properties and (2) approximately $27.3 million of the increase is due to changes in the timing to plug and abandon our facilities.

For the years ended December 31, 2006 and 2005, production taxes totaled $13.5 million and $13.2 million, respectively. Despite a decrease in gas production volumes for the year, 2006 production taxes increased slightly due to a prior year ad valorem tax adjustment on certain of our Rocky Mountain properties expensed in the first quarter of 2006.

Interest expense for 2006 totaled $35.9 million, net of $18.2 million of capitalized interest, compared to interest of $23.2 million, net of $14.9 million of capitalized interest, during 2005. The increase in interest expense in 2006 is primarily the result of increased interest rates and the issuance of our senior floating rate notes.

Reserves. At December 31, 2006, our estimated proved oil and gas reserves totaled 590.9 Bcfe, compared to December 31, 2005 reserves of 593.1 Bcfe. The decrease in estimated proved reserves during 2006 was the result of production and downward revisions of previous estimates exceeding additions from drilling results and acquisitions made during the year. Estimated proved natural gas reserves totaled 342.8 Bcf and estimated proved oil reserves totaled 41.4MMBbls at the end of 2006. The reserve estimates at December 31, 2006 were prepared by engineering firms in accordance with guidelines established by the SEC.

Our standardized measure of discounted future net cash flows was $1.2 billion and $1.9 billion at December 31, 2006 and 2005, respectively. You should not assume that these estimates of future net cash flows represent the fair value of our estimated oil and natural gas reserves. As required by the SEC, we determine these estimates of future net cash flows using market prices for oil and gas on the last day of the fiscal period. The average year-end oil and gas prices net of differentials on all of our properties used in determining these amounts, excluding the effects of hedges in place at year-end, were $56.90 per barrel and $5.39 per Mcf for 2006 and $57.17 per barrel and $9.86 per Mcf for 2005.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

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 **"Item 1A. Risk Factors."**

Accounting Matters and Critical Accounting Policies

Asset Retirement Obligations. Our accounting for asset retirement obligations is governed by Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations". This statement requires us to record our estimate of the fair value of liabilities related to future asset retirement obligations in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of an oil and gas property's useful life. The adoption of SFAS No. 143 requires the use of management's estimates with respect to future abandonment costs, inflation, market risk premiums, useful life and cost of capital. As required by SFAS No. 143, our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

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

We amortize our investment in oil and gas properties through DD&A using the units of production ("UOP") method. Under the UOP method, the quarterly provision for DD&A is computed by dividing production volumes for the period by the total proved reserves as of the beginning of the period, and applying the respective rate to the net cost of proved oil and gas properties, including future development costs.

We capitalize a portion of the interest costs incurred on our debt that is calculated based upon the balance of our unevaluated property costs and our weighted-average borrowing rate. We also capitalize the portion of salaries, general and administrative expenses that are attributable to our acquisition, exploration and development activities.

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

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

Stock-Based Compensation. On December 16, 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), "Share-Based Payments", which is a revision of SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123(R) supersedes Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees", and amends SFAS No. 95, "Statement of Cash Flows." SFAS No. 123(R) became effective for us on January 1, 2006.

We have elected to adopt the requirements of SFAS No. 123(R) using the "modified prospective" method. Under this method, compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS No. 123(R) for all share-based payments granted after the effective date and (b) based on the requirements of SFAS No. 123 for all awards granted prior to the effective date of SFAS No. 123(R) that remain unvested on the effective date. The cumulative net effect of the implementation of SFAS No. 123(R) on net income for the year ended December 31, 2006 was immaterial.

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. During 2007 and 2006, certain of our hedges became ineffective because of differences in the relationship between the fixed price in the derivative contract and actual prices realized. This resulted in expense in the amount of $0.7 million for the year ended December 31, 2007 and income in the amount of $2.7 million for the year ended December 31, 2006. During 2005, certain of our hedges became ineffective when actual production was less than hedged volumes, resulting in a charge to income in the amount of $3.4 million.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates. Our most significant estimates are:

- remaining proved oil and gas reserves volumes and the timing of their production;
- estimated costs to develop and produce proved oil and gas reserves;
- accruals of exploration costs, development costs, operating costs and production revenue;
- timing and future costs to abandon our oil and gas properties;
- the effectiveness and estimated fair value of derivative positions;
- classification of unevaluated property costs;
- capitalized general and administrative costs and interest;
- insurance recoveries related to hurricanes;
- current income taxes; and
- contingencies.

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

Recent Accounting Developments

Fair Value Accounting. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements". SFAS No.157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure about fair value measurements. This statement became effective for us on January 1, 2008.

The Fair Value Option for Certain Items. In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Liabilities – Including an amendment of FASB Statement No. 115". SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. This statement became effective for us January 1, 2008.

Non-controlling Interests & Business Combinations. In December 2007, the FASB issued SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements, an amendment of ARB No. 151" and SFAS No. 141(R), "Business Combinations". These statements are designed to improve, simplify and converge internationally the accounting for business combinations and the reporting of non-controlling interests in consolidated financial statements. These statements are effective for us beginning on January 1, 2009.

We do not anticipate that the implementation of these new standards will have a material effect on our financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure continues to be the pricing applicable to our oil and natural gas production. Our revenues, profitability and future rate of growth depend substantially upon the market prices of oil and natural gas, which fluctuate widely. Oil and natural gas price declines and volatility could adversely affect our revenues, cash flows and profitability. Price volatility is expected to continue. Assuming a 10% decline in realized oil and natural gas prices, including the effects of hedging contracts, we estimate our diluted net income per share for 2007 would have decreased approximately $1.75 per share. In order to manage our exposure to oil and natural gas price declines, we occasionally enter into oil and natural gas price hedging arrangements to secure a price for a portion of our expected future production.

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

We have entered into zero-premium collars with various counterparties for a portion of our expected 2008 oil and natural gas production from the Gulf Coast Basin. The natural gas collar settlements are based on an average of NYMEX prices for the last three days of a respective month. The oil collar settlements are based upon an average of the NYMEX closing price for West Texas Intermediate ("WTI") during the entire calendar month. The contracts require payments to the counterparties if the average price is above the ceiling price or payment from the counterparties if the average price is below the floor price.

The following tables show our hedging positions as of February 11, 2008:

	Zero-Premium Collars					
	Natural Gas			Oil		
	Daily Volume (MMBtus/d)	Floor Price	Ceiling Price	Daily Volume (Bbls/d)	Floor Price	Ceiling Price
2008	30,000*	$8.00	$14.05	3,000	$60.00	$90.20
2008	20,000**	7.50	11.35	2,000	65.00	81.00
2008				3,000	70.00	110.25

*January – March
**April - December

We believe these positions have hedged approximately 36% to 40% of our estimated 2008 production.

Interest Rate Risk

We had long-term debt outstanding of $400 million at December 31, 2007, all of which bears interest at fixed rates. The $400 million of fixed-rate debt is comprised of $200 million of 8¼% Senior Subordinated Notes due 2011 and $200 million of 6¾% Senior Subordinated Notes due 2014. On August 1, 2007, we redeemed in full our $225 million Senior Floating Rate notes at face value with a portion of the proceeds received from the sale of our Rocky Mountain Region properties. Borrowings under our credit facility were paid in full on June 29, 2007 in connection with the sale of our Rocky Mountain Region properties. We currently have no interest rate hedge positions in place to reduce our exposure to changes in interest rates.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information concerning this Item begins on Page F-1.

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

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

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to Stone Energy Corporation and its consolidated subsidiary (collectively "Stone") is made known to the Officers who certify Stone's financial reports and the Board of Directors. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives.

Our chief executive officer and our chief financial officer, with the participation of other members of our senior management, reviewed and evaluated the effectiveness of Stone's disclosure controls and procedures as of December 31, 2007. Based on this evaluation, our chief executive officer and chief financial officer believe:

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

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

Changes in Internal Control Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during our year ended December 31, 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined by the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including the CEO and CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2007. In making this assessment, we used the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation, we have concluded that our internal controls over financial reporting were effective as of December 31, 2007. Ernst and Young LLP, an independent public accounting firm, has issued their report on the Company's internal control over financial reporting as of December 31, 2007.

ITEM 9B. OTHER INFORMATION

None.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Stockholders and Board of Directors
Stone Energy Corporation

We have audited Stone Energy Corporation's internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Stone Energy Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Stone Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Stone Energy Corporation as of December 31, 2007 and 2006, and the related consolidated statements of operations, cash flows, changes in stockholders' equity and comprehensive income for each of the three years in the period ended December 31, 2007 and our report dated February 25, 2008 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
February 25, 2008

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

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

Additional information required by Item 10, including information regarding our audit committee financial experts, is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2008 Annual Meeting of Stockholders to be held on May 15, 2008. The Company has made available free of charge on its Internet Web Site (www.StoneEnergy.com) the Code of Business Conduct and Ethics applicable to all employees of the Company including the Chief Executive Officer, Chief Financial Officer and Principal Accounting Officer.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2008 Annual Meeting of Stockholders to be held on May 15, 2008.

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

The information required by Item 12 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2008 Annual Meeting of Stockholders to be held on May 15, 2008.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by Item 13 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2008Annual Meeting of Stockholders to be held on May 15, 2008.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2008 Annual Meeting of Stockholders to be held on May 15, 2008.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements:

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

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheet as of December 31, 2007 and 2006
Consolidated Statement of Operations for the three years in the period ended December 31, 2007
Consolidated Statement of Cash Flows for the three years in the period ended December 31, 2007
Consolidated Statement of Changes in Stockholders' Equity for the three years in the period ended December 31, 2007
Consolidated Statement of Comprehensive Income for the three years in the period ended December 31, 2007
Notes to the Consolidated Financial Statements

2. Financial Statement Schedules:

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

3. Exhibits:

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

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

3.3 -- Restated Bylaws of the Registrant (incorporated by reference to Exhibit 3.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 001-12074)).

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

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

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

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

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

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

†10.3 -- Stone Energy Corporation Revised (2005) Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.11 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-12074)).

10.4 -- Letter Agreement dated May 19, 2005 between Stone Energy Corporation and Kenneth H. Beer (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed May 24, 2005 (File No. 001-12074)).

10.5 -- Employment Agreement dated January 12, 2006 between Stone Energy Corporation and David H. Welch (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed January 18, 2006 (File No. 001-12074)).

†10.6 -- Stone Energy Corporation Deferred Compensation Plan (incorporated by reference to Exhibit 4.5 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-12074)).

†10.7 -- Adoption Agreement between Fidelity Management Trust Company and Stone Energy Corporation for the Stone Energy Corporation Deferred Compensation Plan dated December 1, 2004 (incorporated by reference to Exhibit 4.6 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-12074)).

10.8 -- Letter Agreement dated June 28, 2007 between Stone Energy Corporation and Richard L. Smith (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K dated June 28, 2007 (File No. 001-12074)).

10.9 -- Credit Agreement between Stone Energy Corporation, the financial institutions named therein and Bank of America N.A., as administrative agent, dated November 1, 2007 (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K dated November 1, 2007 (File No. 001-12074)).

*10.10 -- Stone Energy Corporation Amended and Restated Revised Annual Incentive Compensation Plan (dated November 14, 2007).

10.11 -- Stone Energy Corporation Executive Change of Control and Severance Plan (as amended and restated) dated December 7, 2007 (incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K, filed December 12, 2007 (File No. 001-12074)).

10.12 -- Stone Energy Corporation Employee Change of Control Severance Plan (as amended and restated) dated December 7, 2007 (incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K, filed December 12, 2007 (File No. 001-12074)).

10.13 -- Stone Energy Corporation Executive Change in Control Severance Policy (as amended and restated) dated December 7, 2007 (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed December 12, 2007 (File No. 001-12074)).

*21.1 -- Subsidiaries of the Registrant.

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

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

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

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

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

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* Filed herewith.

† Identifies management contracts and compensatory plans or arrangements.

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

SIGNATURES

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

STONE ENERGY CORPORATION

Date: February 27, 2008

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

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

Signature	Title	Date
/s/ David H. Welch David H. Welch	President, Chief Executive Officer and Director (principal executive officer)	February 27, 2008
/s/ Kenneth H. Beer Kenneth H. Beer	Senior Vice President and Chief Financial Officer (principal financial officer)	February 27, 2008
/s/ J. Kent Pierret J. Kent Pierret	Senior Vice President, Chief Accounting Officer and Treasurer (principal accounting officer)	February 27, 2008
/s/ Robert A. Bernhard Robert A. Bernhard	Director	February 27, 2008
/s/ George R. Christmas George R. Christmas	Director	February 27, 2008
/s/ B.J. Duplantis B.J. Duplantis	Director	February 27, 2008
/s/ John P. Laborde John P. Laborde	Director	February 27, 2008
/s/ Richard A. Pattarozzi Richard A. Pattarozzi	Director	February 27, 2008
/s/ Kay G. Priestly Kay G. Priestly	Director	February 27, 2008
/s/ David R. Voelker David R. Voelker	Director	February 27, 2008

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Stockholders and Board of Directors
Stone Energy Corporation

We have audited the accompanying consolidated balance sheets of Stone Energy Corporation as of December 31, 2007 and 2006, and the related consolidated statements of operations, cash flows, changes in stockholders' equity and comprehensive income for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Stone Energy Corporation as of December 31, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for stock-based compensation.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Stone Energy Corporation's internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 25, 2008

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

	December 31,	
ASSETS	**2007**	**2006**
Current assets:		
Cash and cash equivalents	$475,126	$58,862
Accounts receivable	186,853	241,829
Fair value of hedging contracts	2,163	11,017
Deferred tax asset	9,039	-
Other current assets	521	965
Total current assets	673,702	312,673
Oil and gas properties – United States—full cost method of accounting:		
Proved, net of accumulated depreciation, depletion and amortization of $2,158,327 and $2,706,936, respectively	1,001,179	1,569,947
Unevaluated	150,568	173,925
Oil and gas properties – China – full cost method of accounting:		
Unevaluated, net of accumulated depreciation, depletion and amortization of $8,164 and $0, respectively	29,565	40,553
Building and land, net of accumulated depreciation of $1,497 and $1,331, respectively	5,667	5,811
Fixed assets, net of accumulated depreciation of $14,575 and $18,348, respectively	5,584	8,302
Other assets, net of accumulated depreciation and amortization of $3,802 and $5,550, respectively	23,338	14,244
Fair value of hedging contracts	-	3,016
Total assets	$1,889,603	$2,128,471
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$88,801	$120,532
Undistributed oil and gas proceeds	37,743	39,540
Fair value of hedging contracts	18,968	-
Asset retirement obligations	44,180	130,341
Current income taxes payable	57,631	-
Deferred taxes	-	3,706
Other current liabilities	13,934	16,709
Total current liabilities	261,257	310,828
Long-term debt	400,000	797,000
Deferred taxes	89,665	94,560
Asset retirement obligations	245,610	210,035
Other long-term liabilities	7,269	4,408
Total liabilities	1,003,801	1,416,831
Commitments and contingencies		
Common stock, $.01 par value; authorized 100,000,000 shares; issued 27,767,631 and 27,558,136 shares, respectively	278	276
Treasury stock (22,382 and 22,382 shares, respectively, at cost)	(1,161)	(1,161)
Additional paid-in capital	515,055	502,747
Retained earnings	382,365	200,929
Accumulated other comprehensive income (loss)	(10,735)	8,849
Total stockholders' equity	885,802	711,640
Total liabilities and stockholders' equity	$1,889,603	$2,128,471

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

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Operating revenue:			
Oil production	$424,205	$348,979	$244,469
Gas production	329,047	337,321	391,771
Derivative income, net	-	2,688	-
Total operating revenue	753,252	688,988	636,240
Operating expenses:			
Lease operating expenses	149,702	159,043	114,664
Production taxes	9,945	13,472	13,179
Depreciation, depletion and amortization	302,739	320,696	241,426
Write-down of oil and gas properties	8,164	510,013	-
Accretion expense	17,620	12,391	7,159
Salaries, general and administrative expenses	33,584	34,266	22,705
Incentive compensation expense	5,117	4,356	1,252
Derivative expenses, net	666	-	3,388
Total operating expenses	527,537	1,054,237	403,773
Gain on Rocky Mountain Region properties divestiture	59,825	-	-
Income (loss) from operations	285,540	(365,249)	232,467
Other (income) expenses:			
Interest expense	32,068	35,931	23,151
Interest income	(12,135)	(2,524)	(1,095)
Other income, net	(5,657)	(4,657)	(2,799)
Merger expense reimbursement	-	(51,500)	-
Merger expenses	-	50,029	-
Early extinguishment of debt	844	-	-
Total other expenses, net	15,120	27,279	19,257
Net income (loss) before income taxes	270,420	(392,528)	213,210
Income tax provision (benefit):			
Current	95,579	227	-
Deferred	(6,595)	(138,533)	76,446
Total income taxes	88,984	(138,306)	76,446
Net income (loss)	$181,436	($254,222)	$136,764
Basic earnings (loss) per share	$6.57	($9.29)	$5.07
Diluted earnings (loss) per share	$6.54	($9.29)	$5.02
Average shares outstanding	27,612	27,366	26,951
Average shares outstanding assuming dilution	27,723	27,366	27,244

The accompanying notes are an integral part of this statement.

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Cash flows from operating activities:			
Net income (loss)	$181,436	($254,222)	$136,764
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	302,739	320,696	241,426
Write-down of oil and gas properties	8,164	510,013	-
Accretion expense	17,620	12,391	7,159
Deferred income tax provision (benefit)	(6,595)	(138,533)	76,446
Gain on sale of oil and gas properties	(59,825)	-	-
Settlement of asset retirement obligations	(87,144)	(18,545)	(3,741)
Non-cash stock compensation expense	5,395	4,358	-
Non-cash derivative (income) expense	666	(377)	-
Early extinguishment of debt	844	-	-
Other non-cash expenses	2,259	2,066	3,873
Increase in current income taxes payable	57,508	-	-
(Increase) decrease in accounts receivable	47,549	(30,145)	(24,605)
(Increase) decrease in other current assets	(167)	1,780	(752)
Increase (decrease) in accounts payable	(900)	1,300	2,100
Increase (decrease) in other current liabilities	(4,596)	(11,682)	22,424
Other	205	(65)	119
Net cash provided by operating activities	465,158	399,035	461,213
Cash flows from investing activities:			
Investment in oil and gas properties	(227,651)	(657,878)	(494,125)
Proceeds from sale of oil and gas properties, net of expenses	571,857	(38)	1,549
Sale of fixed assets	691	-	-
Investment in fixed and other assets	(85)	(2,540)	(7,356)
Net cash provided by (used in) investing activities	344,812	(660,456)	(499,932)
Cash flows from financing activities:			
Proceeds from bank borrowings	-	85,000	126,000
Repayment of bank borrowings	(172,000)	(76,000)	(45,000)
Proceeds from issuance of senior floating rate notes	-	225,000	-
Redemption of senior floating rate notes	(225,000)	-	-
Deferred financing costs	(855)	(3,283)	(188)
Excess tax benefits	1,071	-	-
Net proceeds from exercise of stock options and vesting of restricted stock	3,078	9,858	13,358
Net cash provided by (used in) financing activities	(393,706)	240,575	94,170
Net increase (decrease) in cash and cash equivalents	416,264	(20,846)	55,451
Cash and cash equivalents, beginning of year	58,862	79,708	24,257
Cash and cash equivalents, end of year	$475,126	$58,862	$79,708
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$34,083	$31,982	$22,560
Income taxes	36,771	227	-

The accompanying notes are an integral part of this statement.

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

	Common Stock	Treasury Stock	Additional Paid-In Capital	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balance, December 31, 2004	$267	($1,462)	$466,478	($1,486)	$318,425	($9,288)	$ 772,934
Net income	-	-	-	-	136,764	-	136,764
Adjustment for fair value accounting of derivatives, net of tax	-	-	-	-	-	14,144	14,144
Exercise of stock options and vesting of restricted stock	5	-	13,353	-	-	-	13,358
Tax benefit from stock option exercises	-	-	3,796	-	-	-	3,796
Issuance of restricted stock	-	-	17,588	(17,588)	-	-	-
Cancellation of restricted stock	-	-	(1,009)	1,009	-	-	-
Tax benefit from restricted stock vesting	-	-	22	-	-	-	22
Amortization of stock compensation expense	-	-	-	2,997	-	-	2,997
Issuance of treasury stock	-	114	-	-	(6)	-	108
Balance, December 31, 2005	272	(1,348)	500,228	(15,068)	455,183	4,856	944,123
Net loss	-	-	-	-	(254,222)	-	(254,222)
Adjustment for fair value accounting of derivatives, net of tax	-	-	-	-	-	3,993	3,993
Exercise of stock options and vesting of restricted stock	4	-	9,853	-	-	-	9,857
Reverse unearned compensation on restricted stock	-	-	(15,068)	15,068	-	-	-
Amortization of stock compensation expense	-	-	7,734	-	-	-	7,734
Issuance of treasury stock	-	187	-	-	(32)	-	155
Balance, December 31, 2006	276	(1,161)	502,747	-	200,929	8,849	711,640
Net income	-	-	-	-	181,436	-	181,436
Adjustment for fair value accounting of derivatives, net of tax	-	-	-	-	-	(19,584)	(19,584)
Exercise of stock options and vesting of restricted stock	2	-	3,076	-	-	-	3,078
Amortization of stock compensation expense	-	-	8,774	-	-	-	8,774
Tax benefit from stock option exercises and restricted stock vesting	-	-	458	-	-	-	458
Balance, December 31, 2007	$278	($1,161)	$515,055	$ -	$382,365	($10,735)	$885,802

The accompanying notes are an integral part of this statement.

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Net income (loss)	$181,436	($254,222)	$136,764
Other comprehensive income (loss) net of tax effect:			
Adjustment for fair value accounting of derivatives, net of tax	(19,584)	3,993	14,144
Comprehensive income (loss)	$161,852	($250,229)	$150,908

The accompanying notes are an integral part of this statement.

NOTE 1 — ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Stone Energy Corporation is an independent oil and natural gas company engaged in the acquisition and subsequent exploration, development, and operation of oil and gas properties located primarily in the Gulf of Mexico (the "GOM"). Prior to June 29, 2007, we also had significant operations in the Rocky Mountain Basins and the Williston Basin (Rocky Mountain Region). We are also engaged in an exploratory joint venture in Bohai Bay, China and have begun acquiring leasehold interests in Appalachia. Our corporate headquarters are located at 625 E. Kaliste Saloom Road, Lafayette, Louisiana 70508. We have additional offices in New Orleans and Houston.

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

Basis of Presentation:

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

Use of Estimates:

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates are used primarily when accounting for depreciation, depletion and amortization, unevaluated property costs, estimated future net cash flows from proved reserves, cost to abandon oil and gas properties, taxes, reserves of accounts receivable, accruals of capitalized costs, operating costs and production revenue, capitalized employee, general and administrative expenses, effectiveness of financial instruments, the purchase price allocation on properties acquired, current income taxes 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, 2007 and 2006. Our hedging contracts are recorded in the financial statements at fair value in accordance with the Financial Accounting Standards Board's ("FASB") Statement of Financial Accounting Standard ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." As of December 31, 2007 and 2006, the fair value of our $200,000 8¼% Senior Subordinated Notes due 2011 was $202,000 and $198,500, respectively. As of December 31, 2007 and 2006, the fair value of our $200,000 6¾% Senior Subordinated Notes due 2014 was $185,000 and $191,000, respectively. The fair values of our outstanding notes were determined based upon quotes obtained from brokers.

Cash and Cash Equivalents:

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

Oil and Gas Properties:

We follow the full cost method of accounting for oil and gas properties. Under this method, all acquisition, exploration, development and estimated abandonment costs, including certain related employee and general and administrative costs (less any reimbursements for such costs) and interest incurred for the purpose of finding oil and gas are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Employee, general and administrative costs that are capitalized include salaries and all related fringe benefits paid to employees directly engaged in the acquisition, exploration and development of oil and gas properties, as well as all other directly identifiable general and administrative costs associated with such activities, such as rentals, utilities and insurance. Fees received from managed partnerships for providing such services are accounted for as a reduction of capitalized costs. During 2007, 2006 and 2005, we capitalized salaries, general and administrative costs (net of reimbursements) in the amount of $19,993, $23,323 and $20,462, respectively. Employee, general and administrative costs associated with production operations and general corporate activities are expensed in the period incurred. Additionally, workover and maintenance costs incurred solely to maintain or increase levels of production from an existing completion interval are charged to lease operating expense in the period incurred. We capitalize a portion of the interest costs incurred on our debt that is calculated based upon the balance of our unevaluated property costs and our weighted-average borrowing rate. During 2007, 2006 and 2005, we capitalized interest costs of $16,185, $18,221 and $14,877, respectively.

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

We amortize our investment in oil and gas properties through DD&A using the units of production ("UOP") method. Under the UOP method, the quarterly provision for DD&A is computed by dividing production volumes for the period by the total proved reserves as of the beginning of the period, and applying the respective rate to the net cost of proved oil and gas properties, including future development costs.

Under the full cost method of accounting, we compare, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (based on period-end hedge adjusted commodity prices and excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and gas properties net of related deferred taxes. We refer to this comparison as a "ceiling test." If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows (See **Note 4 – Investment in Oil and Gas Properties**).

Sales of oil and gas properties are accounted for as adjustments to the net full cost pool with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Asset Retirement Obligations:

Our accounting for asset retirement obligations is governed by SFAS No. 143, "Accounting for Asset Retirement Obligations". This statement requires us to record our estimate of the fair value of liabilities related to future asset retirement obligations in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of an oil and gas property's useful life. The adoption of SFAS No. 143 requires the use of management's estimates with respect to future abandonment costs, inflation, market risk premiums, useful life and cost of capital. As required by SFAS No. 143, our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

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, 2007 and 2006 included approximately $3,803 and $4,973, 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.

Earnings Per Common Share:

Earnings per common share were calculated by dividing net income applicable to common stock by the weighted-average number of common shares outstanding during the year. Earnings per common share assuming dilution were calculated by dividing net income applicable to common stock by the weighted-average number of common shares outstanding during the year plus the weighted-average number of outstanding dilutive stock options and restricted stock granted to outside directors, officers and employees. There were approximately 110,000 weighted-average dilutive shares for the year ended December 31, 2007. There were no dilutive shares for the year ended December 31, 2006 because we had a net loss for the year. There were approximately 293,000 weighted-average dilutive shares for the year ended December 31, 2005. Stock options that were considered antidilutive because the exercise price of the stock exceeded the average price for the applicable period totaled approximately 747,000, 602,000 and 562,000 shares during 2007, 2006 and 2005, respectively. During the years ended December 31, 2007, 2006 and 2005, approximately 209,000, 372,000 and 483,000 shares of common stock, respectively, were issued, from either authorized shares or shares held in treasury, upon the exercise of stock options and vesting of restricted stock by employees and non-employee directors and the awarding of employee bonus stock pursuant to the 2004 Amended and Restated Stock Incentive Plan.

Production Revenue:

We recognize production revenue under the Entitlement method of accounting. Under this method, revenue is deferred for deliveries in excess of the company's net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production.

Income Taxes:

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

Derivative Instruments and Hedging Activities:

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

Stock-Based Compensation:

On December 16, 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment", which is a revision of SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123(R) supersedes Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees", and amends SFAS No. 95, "Statement of Cash Flows." SFAS No. 123(R) became effective for us on January 1, 2006. We have elected to adopt the requirements of SFAS No. 123(R) using the "modified prospective" method. Under this method, compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS No. 123(R) for all share-based payments granted after the effective date and (b) based on the requirements of SFAS No. 123 for all awards granted prior to the effective date of SFAS No. 123(R) that remain unvested on the effective date. The cumulative net effect of the implementation of SFAS No. 123(R) on net income for the year ended December 31, 2006 was immaterial.

The implementation of SFAS No. 123(R) primarily impacted our 2007 and 2006 financial statements as follows:

- Expense amounts related to stock option issuances are now expensed in the income statement prospectively as opposed to the pro forma disclosures previously presented in prior periods.
- Unearned Compensation and Additional Paid-In Capital balances related to our restricted stock issuances were reversed in 2006.

Recent Accounting Developments:

Fair Value Accounting. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements". SFAS No.157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure about fair value measurements. This statement became effective for us on January 1, 2008.

The Fair Value Option for Certain Items. In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Liabilities – Including an amendment of FASB Statement No. 115". SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. This statement became effective for us January 1, 2008.

Non-controlling Interests & Business Combinations. In December 2007, the FASB issued SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements, an amendment of ARB No. 151" and SFAS No. 141(R), "Business Combinations". These statements are designed to improve, simplify and converge internationally the accounting for business combinations and the reporting of non-controlling interests in consolidated financial statements. These statements are effective for us beginning on January 1, 2009.

We do not anticipate that the implementation of these new standards will have a material effect on our financial statements.

NOTE 2 — ACCOUNTS RECEIVABLE:

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

	As of December 31,	
	2007	2006
Accounts Receivable:		
Other co-venturers	$8,640	$11,837
Trade	103,010	93,987
Insurance receivable on hurricane claims	70,366	130,205
Officers and employees	5	3
Unbilled accounts receivable	4,832	5,797
	$186,853	$241,829

We have accrued insurance claims receivable related to Hurricanes Katrina and Rita to the extent we have concluded the insurance recovery is probable. The accrual is for all costs previously recorded in our financial statements including Asset Retirement Obligations and repair expenses including in Lease Operating Expenses. Included in other long term-assets at December 31, 2007 is $11,531 of accrued hurricane insurance reimbursements attributable to asset retirement obligations estimated to be completed in time frames greater than one year.

NOTE 3 — CONCENTRATIONS:

Sales to Major Customers

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

	December 31,		
	2007	2006	2005
Chevron Texaco E&P Company	19%	(a)	(a)
Conoco, Inc.	16%	12%	10%
Sequent Energy Management LP	(a)	10%	10%
Shell Trading (US) Company	11%	13%	(a)
Total Gas & Power North America, Inc.	(a)	(a)	12%

(a) Less than 10 percent

The maximum amount of credit risk exposure at December 31, 2007 relating to these customers amounted to $43,229.

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

Production and Reserve Volumes

Approximately 92% of our production during 2007 was associated with our Gulf Coast Basin properties. All of our estimated proved reserves (unaudited) at December 31, 2007 were derived from Gulf Coast Basin reservoirs. On June 29, 2007, we sold substantially all of our Rocky Mountain Region properties.

Cash and Cash Equivalents

Substantially all of our cash balances are in excess of federally insured limits. At December 31, 2007 approximately $269,300 was invested in the J.P. Morgan Prime Money Market Fund (Capital Shares). An additional $202,600 was in interest bearing accounts at J.P. Morgan Chase & Co.

NOTE 4 — INVESTMENT IN OIL AND GAS PROPERTIES:

The following table discloses certain financial data relative to our oil and gas producing activities located onshore and offshore the continental United States:

	Year Ended December 31,		
	2007	2006	2005
Oil and gas properties— United States, proved and unevaluated:			
Balance, beginning of year	$4,450,808	$3,691,138	$3,157,670
Costs incurred during the year:			
Capitalized—			
Acquisition costs, net of sales of unevaluated properties	18,730	228,108	138,080
Exploratory costs	16,556	121,883	156,472
Development costs (1)	154,507	370,201	203,577
Sale of Rocky Mountain Region properties (see Note 5)	(1,363,939)	-	-
Salaries, general and administrative costs and interest	33,595	39,958	35,939
Less: overhead reimbursements	(183)	(480)	(600)
Total costs incurred during year, net of divestitures	(1,140,734)	759,670	533,468
Balance, end of year	$3,310,074	$4,450,808	$3,691,138

(1) Includes asset retirement costs of $20,171, $161,048 and $53,687, respectively.

	2007	2006	2005
Charged to expense—			
Lease operating expenses	$149,702	$159,043	$114,664
Production taxes	9,945	13,472	13,179
Accretion expense	17,620	12,391	7,159
	$177,267	$184,906	$135,002
Accumulated depreciation, depletion and amortization—			
Balance, beginning of year	($2,706,936)	($1,880,180)	($1,640,362)
Provision for DD&A	(299,182)	(316,781)	(238,269)
Write-down of oil and gas properties	-	(510,013)	-
Sale of proved properties (see Note 5)	847,791	38	(1,549)
Balance, end of year	($2,158,327)	($2,706,936)	($1,880,180)
Net capitalized costs – United States (proved and unevaluated)	$1,151,747	$1,743,872	$1,810,958
DD&A per Mcfe	$3.67	$4.11	$2.87

At December 31, 2006, our ceiling test computation (See Note 1) resulted in a write-down of oil and gas properties of $510,013 based on a December 31, 2006 Henry Hub gas price of $5.635 per MMBtu and a West Texas Intermediate oil price of $61.05 per barrel. The benefit of hedges in place at December 31, 2006 reduced the write-down by $36,458 net of taxes.

The following table discloses net costs incurred (evaluated) on our unevaluated properties located in the United States for the years indicated:

Unevaluated oil and gas properties—	2007	2006	2005
Net costs incurred (evaluated) during year:			
Acquisition costs	$29,461	$16,007	$87,486
Exploration costs	(5,396)	2,389	37,841
Capitalized interest	10,212	13,828	14,391
	$34,277	$32,224	$139,718

During 2006, we entered into an agreement to participate in the drilling of exploratory wells on two offshore concessions in Bohai Bay, China. After the drilling of three wells, it has been determined that additional drilling will be necessary to evaluate the commercial viability of this project. We have the potential to earn an interest in 750,000 acres on these two concessions. The following table discloses certain financial data relative to our oil and gas producing activities located in Bohai Bay, China:

	Year Ended December 31,		
	2007	2006	2005
Oil and gas properties— China, unevaluated:			
Balance, beginning of year	$40,553	$ -	$ -
Costs incurred during the year:			
Capitalized—			
Exploratory costs	(5,590)	38,488	-
Salaries, general and administrative costs and interest	2,766	2,065	-
Total costs incurred during year	(2,824)	40,553	-
Balance, end of year	$37,729	$40,553	$ -
Accumulated depreciation, depletion and amortization—			
Balance, beginning of year	$ -	$ -	$ -
Write-down of oil and gas properties	(8,164)	-	-
Balance, end of year	($8,164)	$ -	$ -
Net capitalized costs - China (unevaluated)	$29,565	$40,553	$ -

During the fourth quarter of 2007, $8,164 of our investment in China was determined to be impaired and is included as a charge to write-down of oil and gas properties (See Note 1).

The following table discloses financial data associated with unevaluated costs (United States and China) at December 31, 2007:

	Balance as of December 31, 2007	Net Costs Incurred (Evaluated) During the Year Ended December 31,			
		2007	2006	2005	2004 and prior
Acquisition costs	$129,673	$29,461	$53,557	$24,832	$21,823
Exploration costs	24,857	(10,986)	35,843	-	-
Capitalized interest	25,603	12,978	8,399	2,825	1,401
Total unevaluated costs	$180,133	$31,453	$97,799	$27,657	$23,224

Of the total unevaluated costs at December 31, 2007, approximately $29,565 related to our investment in Bohai Bay, China which is expected to be evaluated in the next twelve months. Approximately $84,773 related to seismic costs and is expected to be evaluated in the next forty-eight months. The excluded costs will be included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. Interest costs capitalized on unevaluated properties during the years ended December 31, 2007, 2006 and 2005 totaled $16,185, $18,221 and $14,877, respectively.

NOTE 5 — DISPOSITION OF ASSETS:

On June 29, 2007, we completed the sale of substantially all of our Rocky Mountain Region properties and related assets to Newfield Exploration Company in two separate transactions for a total consideration of $581,958. At December 31, 2006, the estimated proved reserves associated with these assets totaled 182.4 billion cubic feet of natural gas equivalent (Bcfe), which represented 31% of our estimated proved oil and natural gas reserves. Sales of oil and gas properties under the full cost method of accounting are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless the adjustment significantly alters the relationship between capitalized costs and reserves. Since the sale of these oil and gas properties would significantly alter that relationship, we recognized a net gain on the sale of $59,825, computed as follows:

Proceeds from the sale (after post-closing adjustments)	$581,958
Add: Transfer of asset retirement and other obligations	1,823
Less: Transaction costs	(6,088)
Carrying value of oil and gas properties	(516,148)
Carrying value of other assets	(1,720)
Net gain on sale	$59,825

The carrying value of the properties sold was computed by allocating total capitalized costs within the U.S. full cost pool between properties sold and properties retained based on their relative fair values.

NOTE 6 — ASSET RETIREMENT OBLIGATIONS:

Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of a property's useful life. SFAS No. 143 requires that the fair value of a liability to retire an asset be recorded on the balance sheet and that the corresponding cost is capitalized in oil and gas properties. The ARO liability is accreted to its future value and the capitalized cost is depreciated consistent with the UOP method. As required by SFAS No. 143, our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

The change in our ARO during 2007, 2006 and 2005 is set forth below:

	Year Ended December 31,		
	2007	2006	2005
Asset retirement obligations as of the beginning of the year	$340,376	$166,937	$106,091
Liabilities incurred	5,279	10,326	7,461
Liabilities settled	(86,795)	(18,545)	(3,741)
Divestment of properties	(1,233)	-	-
Accretion expense	17,620	12,391	7,159
Revision of estimates	14,543	169,267	49,967
Asset retirement obligations as of the end of the year, including current portion	$289,790	$340,376	$166,937

NOTE 7 — INCOME TAXES:

An analysis of our deferred taxes follows:

	As of December 31,	
	2007	2006
Net operating loss carryforward	$ -	$34,653
Statutory depletion carryforward	-	5,471
Alternative minimum tax credit carryforward	-	909
Temporary differences:		
Oil and gas properties — full cost	(174,314)	(253,526)
Hurricane insurance receivable	(16,246)	-
Asset retirement obligations	101,427	119,856
Stock compensation	3,588	1,790
Hedges	5,881	(4,941)
Other	(962)	(2,478)
	($80,626)	($98,266)

We estimate that we have incurred $95,600 of current federal and state income taxes for calendar year 2007 of which $57,600 is unpaid through December 31, 2007. All of our operating loss and statutory depletion carryforwards were utilized during the year.

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

	Year Ended December 31,		
	2007	2006	2005
Income tax expense computed at the statutory federal income tax rate	35.0%	(35.0%)	35.0%
Domestic production activities deduction	(1.6)	-	-
State taxes and other	(0.5)	(0.1)	0.9
Reversal of valuation allowance	-	(0.1)	-
Effective income tax rate	32.9%	(35.2%)	35.9%

In 2007, we recognized a tax deduction for domestic production activities pursuant to Internal Revenue Code Section 199. This deduction was not previously available to us due to our tax operating loss position.

Income taxes allocated to accumulated other comprehensive income related to oil and gas hedges amounted to ($10,587), $2,192 and $7,615 for the years ended December 31, 2007, 2006 and 2005, respectively.

We adopted the provisions of FASB Interpretation No. 48 Accounting for Uncertainty in Income Taxes ("FIN 48") on January 1, 2007. The cumulative net effect of the implementation of FIN 48 on our financial statements was immaterial. As of December 31, 2007 and 2006, we had unrecognized tax benefits of $1,178. All of our unrecognized tax benefits will impact our tax rate if recognized.

A reconciliation of the total amounts of unrecognized tax benefits follows:

Total unrecognized tax benefits as of January 1, 2007	$1,178
Increases (decreases) in unrecognized tax benefits as a result of:	
Tax positions taken during a prior period	-
Tax positions taken during the current period	-
Settlements with taxing authorities	-
Lapse of applicable statute of limitations	-
Total unrecognized tax benefits as of December 31, 2007	$1,178

It is our policy to classify interest and penalties associated with underpayment of income taxes as interest expense and general and administrative expenses, respectively. For the year ended December 31, 2007, no interest or penalties were incurred related to underpayment of income taxes. As of December 31, 2007 and 2006, there were no accrued interest and penalties relating to prior periods.

The tax years 2004 through 2007 remain subject to examination by major tax jurisdictions.

NOTE 8 — LONG-TERM DEBT:

Long-term debt consisted of the following:

	As of December 31,	
	2007	2006
8¼% Senior Subordinated Notes due 2011	$200,000	$200,000
6¾% Senior Subordinated Notes due 2014	200,000	200,000
Senior Floating Rate Notes due 2010	-	225,000
Bank debt	-	172,000
Total long-term debt	$400,000	$797,000

At December 31, 2007, we had no outstanding borrowings under our bank credit facility and letters of credit totaling $52,821 had been issued pursuant to the facility. Effective June 29, 2007, in connection with the sale of substantially all of our Rocky Mountain Region properties, our borrowing base under the credit facility was reduced from $250,000 to $85,400. On November 1, 2007, we entered into a new $300,000 senior secured credit facility, maturing July 1, 2011, with a syndicated bank group. The new facility has an initial borrowing base of $175,000 and replaces the previous $500,000 credit facility. We recorded a pre-tax charge in the fourth quarter of 2007 in the amount of $252 for the early extinguishment of debt of the old facility. As of February 11, 2008, after accounting for the $52,821 of letters of credit, we had $122,179 of borrowings available under the new credit facility. 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 under the credit facility is re-determined periodically based on the bank group's evaluation of our proved oil and gas reserves. The facility provides for a valid, perfected first-priority lien in favor of the participating banks on the majority of our oil and gas properties.

Under the financial covenants of our new credit facility, we must (i) maintain a ratio of consolidated debt to consolidated EBITDA, as defined in the credit agreement, for the preceding four quarterly periods of not greater than 3.25 to 1 and (ii) maintain a ratio of EBITDA to consolidated Net Interest, as defined in the credit agreement, for the preceding four quarterly periods of not less than 3.0 to 1.0. In addition, the new credit facility places certain customary restrictions or requirements with respect to disposition of properties, incurrence of additional debt, change of ownership and reporting responsibilities. These covenants may limit or prohibit us from paying cash dividends but do allow for limited stock repurchases. The violation of any of these covenants could give rise to a default, which if not cured could give the lenders under the facility a right to accelerate payment.

On August 1, 2007, we redeemed our Senior Floating Rate Notes at their face value of $225,000. The redemption was funded through the proceeds received from the sale of substantially all of our Rocky Mountain Region properties on June 29, 2007. We recorded a pre-tax charge of $592 in the third quarter of 2007 for the early extinguishment of debt.

On December 15, 2004, we issued $200,000 6¾% Senior Subordinated Notes due 2014. The notes were sold at par value and we received net proceeds of $195,500 and are subordinated to our senior unsecured credit facility and rank *pari passu* with our 8¼% Senior Subordinated Notes. There is no sinking fund requirement and the notes are redeemable at our option, in whole but not in part, at any time before December 15, 2009 at a Make-Whole Amount. Beginning December 15, 2009, the notes are redeemable at our option, in whole or in part, at 103.375% of their principal amount and thereafter at prices declining annually to 100% on and after December 15, 2012. In addition, before December 15, 2007, we may redeem up to 35% of the aggregate principal amount of the notes issued with net proceeds from an equity offering at 106.75%. The notes provide for certain covenants, which include, without limitation, restrictions on liens, indebtedness, asset sales, dividend payments and other restricted payments. The violation of any of these covenants could give rise to a default, which if not cured could give the holder of the notes a right to accelerate payment. At December 31, 2007, $563 had been accrued in connection with the June 15, 2008 interest payment.

On December 5, 2001, we issued $200,000 8¼% Senior Subordinated Notes due 2011. The notes were sold at par value and we received net proceeds of $195,500 and are subordinated to our senior unsecured credit facility and rank *pari passu* with our 6¾% Senior Subordinated Notes. There is no sinking fund requirement and the notes are redeemable at our option, in whole but not in part, at any time before December 15, 2006 at a Make-Whole Amount. Beginning December 15, 2006, the notes are redeemable at our option, in whole or in part, at 104.125% of their principal amount and thereafter at prices declining annually to 100% on and after December 15, 2009. The notes provide for certain covenants, which include, without limitation, restrictions on liens, indebtedness, asset sales, dividend payments and other restricted payments. The violation of any of these covenants could give rise to a default, which if not cured could give the holder of the notes a right to accelerate payment. At December 31, 2007, $688 had been accrued in connection with the June 15, 2008 interest payment.

Other assets at December 31, 2007 and 2006 included approximately $7,418 and $10,411, respectively, of deferred financing costs, net of accumulated amortization. These costs at December 31, 2007 related primarily to the issuance of the 8¼% notes, the 6¾% notes and the bank credit facility. The costs associated with the 8¼% notes and the 6¾% notes are being amortized over the life of the notes using a method that applies effective interest rates of 8.6% and 7.1%, respectively. The costs associated with the credit facility are being amortized over the term of the facility.

Total interest cost incurred on all obligations for the years ended December 31, 2007, 2006 and 2005 was $48,253, $54,152 and $38,100 respectively.

NOTE 9 STOCK-BASED COMPENSATION:

On December 16, 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment", which is a revision of SFAS No. 123. SFAS No. 123(R) supersedes APB Opinion No. 25 and amends SFAS No. 95, "Statement of Cash Flows". SFAS No. 123(R) became effective for us on January 1, 2006. The cumulative net effect of the implementation of SFAS No. 123(R) on net income (loss) for the year ended December 31, 2006 was immaterial.

We elected to adopt the requirements of SFAS No. 123(R) using the "modified prospective" method. Under this method, compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS No. 123(R) for all share-based payments granted after the effective date and (b) based on the requirements of SFAS No. 123 for all awards granted prior to the effective date of SFAS No. 123(R) that remain unvested on the effective date. For the year ended December 31, 2007, we incurred $8,775 of stock-based compensation, of which $6,177 related to restricted stock issuances and $2,598 related to stock option grants and of which a total of approximately $3,380 was capitalized into Oil and Gas Properties. For the year ended December 31, 2006, we incurred $9,190 of stock-based compensation, of which $5,452 related to restricted stock issuances, $3,584 related to stock option grants and $154 related to employee bonus stock awards and of which a total of approximately $4,136 was capitalized into Oil and Gas Properties. Because of the non-cash nature of stock based compensation, the expensed portion of stock based compensation is added back to the net income (loss) in arriving at net cash provided by operating activities in our statement of cash flow. The capitalized portion is not included in net cash used in investing activities.

For the year ended December 31, 2005, if stock-based compensation expense had been determined consistent with the expense recognition provisions under SFAS No. 123, our net income, basic earnings per share and diluted earnings per share would have approximated the pro forma amounts below:

	Year Ended December 31, 2005 (In thousands, except per share amounts)
Net income	$136,764
Add: Stock-based compensation expense included in net income, net of tax	909
Less: Stock-based compensation expense using fair value method, net of tax	(2,601)
Pro forma net income	$135,072
Basic earnings per share	$5.07
Pro forma basic earnings per share	$5.01
Diluted earnings per share	$5.02
Pro forma diluted earnings per share	$4.96

Under our 2004 Amended and Restated Stock Incentive Plan (the "Plan"), we may grant both incentive stock options qualifying under Section 422 of the Internal Revenue Code and options that are not qualified as incentive stock options to all employees and directors. All such options must have an exercise price of not less than the fair market value of the common stock on the date of grant and may not be re-priced without stockholder approval. Stock options to all employees vest ratably over a five-year service-vesting period and expire ten years subsequent to award. Stock options issued to non-employee directors vest ratably over a three-year service-vesting period and expire ten years subsequent to award. In addition, the Plan provides that shares available under the Plan may be granted as restricted stock. Restricted stock typically vests over a three-year period.

Stock Options. Stock options granted and related fair values for the years ended December 31, 2007, 2006 and 2005 are listed in the following table. Fair value for the years ended December 31, 2007, 2006 and 2005, was determined using the Black-Scholes option pricing model with the following assumptions:

	2007	2006	2005
	(Amounts in table represent actual values except where indicated otherwise)		
Stock options granted	25,000	15,000	85,500
Fair value of stock options granted ($ in thousands)	$342	$314	$1,780
Weighted average grant date fair value	$13.66	$20.90	$20.81
Assumptions:			
Dividend yield	0.00%	0.00%	0.00%
Expected volatility	33.01%	36.59%	36.47%
Risk-free rate	4.60%	4.58%	3.84%
Expected option life	6.0 years	6.0 years	6.0 years
Forfeiture rate	10.00%	10.00%	0.00%

Expected volatility and expected option life are based on a historical average. The risk-free rate is based on quoted rates on zero-coupon Treasury Securities for terms consistent with the expected option life.

A summary of stock option activity under the Plan during the year ended December 31, 2007 is as follows (amounts in table represent actual values except where indicated otherwise):

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Term	Aggregate Intrinsic Value (in thousands)
Options outstanding, beginning of period	1,394,835	$42.87		
Granted	25,000	33.19		
Exercised	(127,636)	33.29		$707
Forfeited	(52,490)	37.42		
Expired	(308,120)	44.40		
Options outstanding, end of period	931,589	43.72	4.7 years	5,254
Options exercisable, end of period	736,659	43.74	4.1 years	4,475
Options unvested, end of period	194,930	43.64	7.0 years	779

Exercise prices for stock options outstanding at December 31, 2007 range from $29.16 to $61.93.

A summary of stock option activity under the Plan during the year ended December 31, 2006 is as follows (amounts in table represent actual values except where indicated otherwise):

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Term	Aggregate Intrinsic Value (in thousands)
Options outstanding, beginning of period	1,902,062	$41.99		
Granted	15,000	47.75		
Exercised	(290,219)	33.96		$3,545
Forfeited	(107,077)	37.63		
Expired	(124,931)	55.29		
Options outstanding, end of period	1,394,835	42.87	4.5 years	759
Options exercisable, end of period	1,018,716	43.15	3.6 years	751
Options unvested, end of period	376,119	42.09	7.0 years	8

A summary of stock option activity under the Plan during the year ended December 31, 2005 is as follows (amounts in table represent actual values except where indicated otherwise):

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Term	Aggregate Intrinsic Value (in thousands)
Options outstanding, beginning of period	2,541,135	$39.47		
Granted	85,500	49.54		
Exercised	(486,127)	29.00		$10,845
Forfeited	(154,163)	37.73		
Expired	(84,283)	56.43		
Options outstanding, end of period	1,902,062	41.99	5.7 years	6,496
Options exercisable, end of period	1,160,669	42.72	4.5 years	3,114
Options unvested, end of period	741,993	40.84	7.5 years	3,382

Restricted Stock. The fair value of restricted shares is determined based on the average of the high and low prices on the issuance date and assumes a 5% forfeiture rate in 2007 and 2006. During the year ended December 31, 2007, we issued 193,084 shares of restricted stock valued at $6,576. During the year ended December 31, 2006, we issued 151,150 shares of restricted stock valued at $6,220. During the year ended December 31, 2005, we issued 338,000 shares of restricted stock valued at $17,589.

A summary of the restricted stock activity under the Plan for the years ended December 31, 2007, 2006 and 2005 is as follows (amounts in table represent actual values):

	2007		2006		2005	
	Number of Restricted Shares	Wgtd. Avg. Fair Value Per Share	Number of Restricted Shares	Wgtd. Avg. Fair Value Per Share	Number of Restricted Shares	Wgtd. Avg. Fair Value Per Share
Restricted stock outstanding, beginning of period	328,447	$46.97	344,038	$51.52	33,710	$44.91
Issuances	193,084	34.06	151,150	41.15	338,000	52.04
Lapse of restrictions	(114,740)	48.01	(106,261)	51.39	(8,272)	44.76
Forfeitures	(95,305)	42.74	(60,480)	50.50	(19,400)	52.01
Restricted stock outstanding, end of period	311,486	$39.86	328,447	$46.97	344,038	$51.52

As of December 31, 2007, there was $10,579 of unrecognized compensation cost related to all non-vested share-based compensation arrangements under the Plan. That cost is being amortized on a straight-line basis over the vesting period and is expected to be recognized over a weighted-average period of 1.7 years. Subsequent to December 31, 2007, 233,786 shares of restricted stock and 40,000 stock options were granted under the Plan.

The adoption of SFAS No. 123(R) changed the accounting for tax benefits and deficits associated with the differences between book compensation and tax deductions associated with stock based compensation. If tax deductions exceed book compensation, then excess tax benefits are credited to additional paid-in-capital to the extent realized. If book compensation expense exceeds tax deductions, the tax deficit results in either a reduction in additional-paid-in-capital or an increase in income tax expense depending on certain circumstances. Credits to additional-paid-in-capital for net tax benefits were $458, $0 and $3,818 in 2007, 2006 and 2005, respectively.

NOTE 10 SUBSEQUENT EVENT:

In early 2008, we completed the divesture of a small package of Gulf of Mexico properties which totaled 18 Bcfe of reserves at December 31, 2007 and a projected 9 MMcfe per day of production in 2008 for a cash consideration of approximately $20,000 before closing adjustments. The properties that were sold had estimated abandonment costs of $33,500. These properties were mature, high cost properties with minimal exploitation or exploration opportunities.

NOTE 11 SHARE REPURCHASE PROGRAM:

On September 24, 2007, our Board of Directors authorized a share repurchase program for an aggregate amount of up to $100,000. The shares may be repurchased from time to time in the open market or through privately negotiated transactions. The repurchase program is subject to business and market conditions, and may be suspended or discontinued at any time. Through December 31, 2007 no shares had been repurchased.

NOTE 12 TERMINATED MERGERS:

Included in the 2006 net loss is $51,500 in merger expense reimbursements partially offset by $50,029 in merger related expenses. Merger expenses include a $43,500 termination fee incurred in connection with the proposed merger with Energy Partners Ltd, ("EPL"). Prior to entering into the EPL merger agreement, we terminated our merger agreement with Plains Exploration and Production Company ("Plains") and Plains Acquisition Corp. ("Plains Acquisition") on June 22, 2006. As required under the terms of the terminated merger agreement among Stone, Plains and Plains Acquisition, Plains was entitled to a termination fee of $43,500 ("Plains Termination Fee"), which was advanced by EPL to Plains on June 22, 2006. Pursuant to the EPL merger agreement, we were obligated to repay all or a portion of this termination fee under certain circumstances if the EPL merger was not consummated. The $43,500 termination fee was recorded as merger expenses in the income statement during the second quarter of 2006. Of this amount, $25,300 was potentially reimbursable to EPL under certain circumstances described in the EPL merger agreement and therefore was recorded as deferred revenue on the balance sheet as of June 30, 2006 and September 30, 2006. The remaining $18,200 of the termination fee was recorded as merger expense reimbursement in the income statement during the three months ended June 30, 2006.

On October 11, 2006, we entered into an agreement with EPL pursuant to which the EPL merger agreement was terminated. Pursuant to the termination of the EPL merger agreement, EPL paid us $8,000 and released all claims to the $43,500 Plains Termination Fee. The $8,000 fee paid to us by EPL in conjunction with the termination of the EPL merger agreement was recorded as merger expense reimbursement in the income statement in the fourth quarter of 2006. Additionally, the remaining $25,300 of the Plains Termination Fee was recognized as merger expense reimbursement in earnings in the fourth quarter of 2006.

NOTE 13 — HEDGING ACTIVITIES:

We enter into hedging transactions to secure a commodity price for a portion of future production that is acceptable at the time of the transaction. The primary objective of these activities is to reduce our exposure to the risk of declining oil and natural gas prices during the term of the hedge. These hedges are designated as cash flow hedges upon entering into the contract. We do not enter into hedging transactions for trading purposes.

Under Statement of Financial Accounting Standards ("SFAS") No. 133, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. If the instrument qualifies for hedge accounting treatment, it is recorded as either an asset or liability measured at fair value and subsequent changes in the derivative's fair value are recognized in equity through other comprehensive income, to the extent the hedge is considered effective. Additionally, monthly settlements of effective hedges are reflected in revenue from oil and gas production and cash flows from operations. Instruments not qualifying for hedge accounting are recorded in the balance sheet at fair value and changes in fair value are recognized in earnings through derivative expense (income). Monthly settlements of ineffective hedges are recognized in earnings through derivative expense (income) and cash flows from operations.

Stone has entered into zero-premium collars with various counterparties for a portion of our expected 2008 oil and natural gas production from the Gulf Coast Basin. The natural gas collar settlements are based on an average of New York Mercantile Exchange ("NYMEX") prices for the last three days of a respective month. The oil collar settlements are based upon an average of the NYMEX closing price for West Texas Intermediate ("WTI") during the entire calendar month. The contracts require payments to the counterparties if the average price is above the ceiling price or payment from the counterparties if the average price is below the floor price. Our outstanding collars are with Bank of America, N.A., BNP Paribas and JP Morgan. During the years ended December 31, 2007 and 2006, certain of our derivative contracts were determined to be partially ineffective because of differences in the relationship between the fixed price in the derivative contract and actual prices realized.

During 2005 we utilized oil and gas collar contracts in the Gulf Coast Basin and fixed-price swaps to hedge a portion of our future gas production from our Rocky Mountain Region properties. Our swap contracts were with Bank of America and were based upon Inside FERC published prices for natural gas deliveries at Kern River. Swaps typically provide for monthly payments by us if prices rise above the swap price or to us if prices fall below the swap price. The last of these contracts terminated on December 31, 2005. One of our collar contracts for September, October and November 2005 became ineffective when curtailments of our oil production resulting from Hurricanes Katrina and Rita resulted in production levels less than hedged amounts.

During the year ended December 31, 2007, we realized a net increase in natural gas revenue related to our effective zero-premium collars of $10,438 and a net decrease in oil revenue of $2,554. During the year ended December 31, 2006, we realized a net increase in oil revenue and natural gas revenue related to our effective zero-premium collars of $89 and $36,953, respectively. We realized a net decrease of $31,231 in natural gas revenue related to our effective swaps and a net decrease of $10,936 in oil revenue related to our effective zero-premium collars for the year ended December 31, 2005.

At December 31, 2007, we had accumulated other comprehensive loss of $10,735, net of tax, which related to our 2008 collar contracts. We believe this amount approximates the estimated amount to be reclassified into earnings in the next year.

Derivative expense (income) for the years ended December 31, 2007, 2006 and 2005 consisted of the following:

	Year Ended December 31,		
	2007	2006	2005
Cash settlement on the ineffective portion of derivatives	$ -	($2,311)	$3,388
Changes in fair market value of ineffective portion of derivatives	666	(377)	-
Total derivative expense (income)	$666	($2,688)	$3,388

The following table shows our hedging positions as of February 11, 2008:

	Zero-Premium Collars					
	Natural Gas			Oil		
	Daily Volume (MMBtus/d)	Floor Price	Ceiling Price	Daily Volume (Bbls/d)	Floor Price	Ceiling Price
2008	30,000*	$8.00	$14.05	3,000	$60.00	$90.20
2008	20,000**	7.50	11.35	2,000	65.00	81.00
2008				3,000	70.00	110.25

*January – March
**April - December

NOTE 14 — COMMITMENTS AND CONTINGENCIES:

We lease office facilities in New Orleans, Louisiana, Houston, Texas and Morgantown, West Virginia under the terms of long-term, non-cancelable leases expiring on various dates through 2010. We also lease certain equipment on our oil and gas properties typically on a month-to-month basis. The minimum net annual commitments under all leases, subleases and contracts noted above at December 31, 2007 were as follows:

2008	$307
2009	287
2010	271

Payments related to our lease obligations for the years ended December 31, 2007, 2006 and 2005 were approximately $530, $690 and $876 respectively. We subleased office space to third parties for the year ended 2005 and recorded related receipts of $86.

We are contingently liable to surety insurance companies in the aggregate amount of $73,765 relative to bonds issued on our behalf to the United States Department of the Interior Minerals Management Service (MMS), federal and state agencies and certain third parties from which we purchased oil and gas working interests. The bonds represent guarantees by the surety insurance companies that we will operate in accordance with applicable rules and regulations and perform certain plugging and abandonment obligations as specified by applicable working interest purchase and sale agreements.

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

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

In connection with our exploration efforts, specifically in the deep water of the Gulf of Mexico, we have committed to acquire seismic data from certain providers on multiple offshore blocks over the next two years. As of December 31, 2007, our seismic data purchase commitments totaled $16,336 to be incurred over the next year.

On April 23, 2007, Stone received notification from the Staff of the SEC that its inquiry into the revision of Stone's proved reserves had been terminated and no enforcement action had been recommended. In 2005, Stone had received notice that the Staff of the SEC was conducting an inquiry into the revision of Stone's proved reserves and the financial statement restatement.

On December 30, 2004, Stone was served with two petitions (civil action numbers 2004-6227 and 2004-6228) filed by the Louisiana Department of Revenue ("LDR") in the 15th Judicial District Court (Parish of Lafayette, Louisiana) claiming additional franchise taxes due. In one case, the LDR is seeking additional franchise taxes from Stone in the amount of $640, plus accrued interest of $352 (calculated through December 15, 2004), for the franchise year 2001. In the other case, the LDR is seeking additional franchise taxes from Stone (as successor to Basin Exploration, Inc.) in the amount of $274, plus accrued interest of $159 (calculated through December 15, 2004), for the franchise years 1999, 2000 and 2001. Further, on December 29, 2005, the LDR filed another petition in the 15th Judicial District Court claiming additional franchise taxes due for the taxable years ended December 31, 2002 and 2003 in the amount of $2,600 plus accrued interest calculated through December 15, 2005 in the amount of $1,200. Also, on January 2, 2008, Stone was served with a petition (civil action number 2007-6754) claiming $1,500 of additional franchise taxes due for the 2004 franchise year, plus accrued interest of $800 calculated through November 30, 2007. These assessments all relate to the LDR's assertion that sales of crude oil and natural gas from properties located on the Outer Continental Shelf, which are transported through the state of Louisiana, should be sourced to the state of Louisiana for purposes of computing the Louisiana franchise tax apportionment ratio. The Company disagrees with these contentions and intends to vigorously defend itself against these claims. The franchise tax years 2005, 2006 and 2007 remain subject to examination.

Stone has received an inquiry from the Philadelphia Stock Exchange investigating matters including trading prior to Stone's October 6, 2005 announcement regarding the revision of Stone's proved reserves. Stone cooperated fully with this inquiry. Stone has not received any further inquires form the Philadelphia Exchange since the original request for information.

On or around November 30, 2005, George Porch filed a putative class action in the United States District Court for the Western District of Louisiana (the "Federal Court") against Stone, David Welch, Kenneth Beer, D. Peter Canty and James Prince purporting to allege violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934. Three similar complaints were filed soon thereafter. All complaints had asserted a putative class period commencing on June 17, 2005 and ending on October 6, 2005. All complaints contended that, during the putative class period, defendants, among other things, misstated or failed to disclose (i) that Stone had materially overstated Stone's financial results by overvaluing its oil reserves through improper and aggressive reserve methodologies; (ii) that the Company lacked adequate internal controls and was therefore unable to ascertain its true financial condition; and (iii) that as a result of the foregoing, the values of the Company's proved reserves, assets and future net cash flows were materially overstated at all relevant times. On March 17, 2006, these purported class actions were consolidated, with El Paso Fireman & Policeman's Pension Fund designated as Lead Plaintiff ("Securities Action"). Lead Plaintiff filed a consolidated class action complaint on or about June 14, 2006. The consolidated complaint alleges claims similar to those described above and expands the putative class period to commence on May 2, 2001 and to end on March 10, 2006. On September 13, 2006, Stone and the individual defendants filed motions seeking dismissal of that action.

On August 17, 2007, a Federal Magistrate Judge issued a report and recommendation (the "Report") recommending that the Federal Court grant in part and deny in part the Motions to Dismiss. The Report recommended that (i) the claims asserted against defendants Kenneth Beer and James Prince pursuant to Section 10(b) of the Securities Exchange Act and Rule 10b-5 promulgated thereunder and (ii) claims asserted on behalf of putative class members who sold their Company shares prior to October 6, 2005 be dismissed and that the Motions to Dismiss be denied with respect to the other claims against Stone and the individual defendants.

On October 1, 2007, the Federal Court issued an Order directing that judgment on the Motions to Dismiss be entered in accordance with the recommendations of the Report. On October 23, 2007, Stone and the individual defendants filed a motion seeking permission to appeal the denial of the Motions to Dismiss to the Fifth Circuit Court of Appeals, which motion was denied. The discovery process is now underway. The parties have exchanged initial disclosures and several document requests and interrogatories. Stone has begun producing documents in response to Lead Plaintiff's requests.

In addition, on or about December 16, 2005, Robert Farer and Priscilla Fisk filed respective complaints in the Federal Court purportedly alleging claims derivatively on behalf of Stone. Similar complaints were filed thereafter in the Federal Court by Joint Pension Fund, Local No. 164, I.B.E.W., and in the 15th Judicial District Court, Parish of Lafayette, Louisiana (the "State Court") by Gregory Sakhno. Stone was named as a nominal defendant and David Welch, Kenneth Beer, D. Peter Canty, James Prince, James Stone, John Laborde, Peter Barker, George Christmas, Richard Pattarozzi, David Voelker, Raymond Gary, B.J. Duplantis and Robert Bernhard were named as defendants in these actions. The State Court action purportedly alleged claims of breach of fiduciary duty, abuse of control, gross mismanagement, and waste of corporate assets against all defendants, and claims of unjust enrichment and insider selling against certain individual defendants. The Federal Court derivative actions asserted purported claims against all defendants for breach of fiduciary duty, abuse of control, gross mismanagement, waste of corporate assets and unjust enrichment and claims against certain individual defendants for breach of fiduciary duty and violations of the Sarbanes-Oxley Act of 2002.

On March 30, 2006, the Federal Court entered an order naming Robert Farer, Priscilla Fisk and Joint Pension Fund, Local No. 164, I.B.E.W. as co-lead plaintiffs in the Federal Court derivative action and directed the lead plaintiffs to file a consolidated amended complaint within forty-five days. On April 22, 2006, the complaint in the State Court derivative action was amended to also assert claims on behalf of a purported class of shareholders of Stone. In addition to the above mentioned claims, the amended State Court derivative action complaint purported to allege breaches of fiduciary duty by the director defendants in connection with the then proposed merger transaction with Plains Exploration and Production Company ("Plains") and seeks an order enjoining the director defendants from entering into the then proposed transaction with Plains. On May 15, 2006, the first consolidated complaint in the Federal Court derivative action was filed; it contained a similar injunctive claim. On September 15, 2006, co-lead plaintiffs' in the Federal Court derivative action further amended their complaint to seek an order enjoining Stone's proposed merger with Energy Partners, Ltd. ("EPL") based on substantially the same grounds previously asserted regarding the prior proposed transaction with Plains. On October 2, 2006, each of the defendants in the Federal Court derivative action filed or joined in motions seeking dismissal of all or part of that action. Those motions were denied without prejudice on November 30, 2006 when the Federal Court granted the co-lead plaintiffs leave to file a third amended complaint. Following the filing of the third amended complaint in the Federal Court derivative action, defendants filed motions seeking to have that action either dismissed or stayed until resolution of the pending motion to dismiss the Securities Action before the Federal Court. On December 21, 2006 the Federal Court stayed the Federal Court derivative action at least until resolution of the then-pending motion to dismiss the Securities Action after which time a hearing was to be conducted by the Federal Court to determine the propriety of maintaining that stay. As of the date hereof, the Federal Court has yet to consider any potential modification of the stay.

Stone's Certificate of Incorporation and/or its Restated Bylaws provide, to the extent permissible under the law of Delaware (Stone's state of incorporation), for indemnification of and advancement of defense costs to Stone's current and former directors and officers for potential liabilities related to their service to Stone. Stone has purchased directors and officers insurance policies that, under certain circumstances, may provide coverage to Stone and/or its officers and directors for certain losses resulting from securities-related civil liabilities and/or the satisfaction of indemnification and advancement obligations owed to directors and officers. These insurance policies may not cover all costs and liabilities incurred by Stone and its current and former officers and directors in these regulatory and civil proceedings.

The foregoing pending actions are at an early stage and subject to substantial uncertainties concerning the outcome of material factual and legal issues relating to the litigation and the regulatory proceedings. Accordingly, based on the current status of the litigation and inquiries, we cannot currently predict the manner and timing of the resolution of these matters and are unable to estimate a range of possible losses or any minimum loss from such matters. Furthermore, to the extent that our insurance policies are ultimately available to cover any costs and/or liabilities resulting from these actions, they may not be sufficient to cover all costs and liabilities incurred by us and our current and former officers and directors in these regulatory and civil proceedings.

On or around August 28, 2006, ATS, Inc. instituted an action (the "ATS Litigation") in the Delaware Court of Chancery for New Castle County (the "Delaware Court"). The initial complaint in the ATS Litigation, among other things, challenged certain provisions of the EPL Merger Agreement pursuant to which EPL (i) paid the $43,500 Plains Termination Fee; and (ii) agreed, under certain contractually specified conditions, to pay Stone $25,600 in the event of a future termination of the Merger Agreement (the "EPL Termination Fee"). On or around September 12, 2006, a purported shareholder of EPL filed a purported class action in the Delaware Court (the "Farrington Action"). The initial Farrington Action complaint asserted claims similar to those in the ATS Litigation and sought, among other things, a damages recovery in the amount of the Plains Termination Fee.

On or around September 7, 2006, EPL commenced an action against Stone in the Delaware Court (the "Declaratory Action"), in which EPL sought a declaratory judgment with respect to EPL's rights and obligations under Section 6.2(e) of the Merger Agreement. On September 11, 2006, the Delaware Court expedited the Declaratory Action and consolidated with the Declaratory Action a portion of the ATS Litigation in which ATS likewise asserted claims respecting Section 6.2(e) of the Merger Agreement. By oral ruling on September 27, 2006, and subsequent written opinion dated October 11, 2006, the Delaware Court ruled, among other things, that Section 6.2(e) of the Merger Agreement did not limit the ability of EPL to explore and negotiate, in good faith, with respect to any Third Party Acquisition Proposals (as defined in the Merger Agreement), including the tender offer by ATS, Inc. for all of the outstanding shares of EPL stock at $23.00 per share ("ATS Offer"). The Delaware Court dismissed without prejudice the remainder of the claims raised by EPL in the Declaratory Action as not ripe for a judicial determination.

On October 11, 2006, EPL and Stone entered into an agreement (the "Termination and Release Agreement") pursuant to which they agreed, among other things, (i) to enter into a mutual termination of the Merger Agreement, (ii) to mutually release certain actual or potential claims or rights of action, (iii) to mutually seek a dismissal of the Declaratory Action, and (iv) that EPL would make a payment of S8 million to Stone (the "$8 Million Payment"). EPL made the $8 Million Payment to Stone. On October 13, 2006, the Declaratory Action was dismissed by stipulation of the parties and order of the Delaware Court.

On or around October 16, 2006, following the execution of the Termination and Release Agreement, plaintiffs in both the ATS Litigation and the Farrington Litigation sought (and were later granted leave by the Court) to file Second Amended Complaints that, among other things, added claims seeking a recovery in the amount of the $8 Million Payment. On October 26, 2006, ATS voluntarily dismissed the ATS Litigation without prejudice. On November 2, 2006, Stone and EPL filed motions to dismiss the Farrington Action, and on September 10, 2007, the parties filed a Stipulation and Order dismissing the Farrington action without prejudice, which was granted. No compensation in any form passed from any of the defendants to plaintiff or his attorneys. The court retained jurisdiction over plaintiff's claim for award of attorneys' fees and reimbursement of litigation costs and expenses. Plaintiffs have confirmed that they will not be seeking any fees or expenses from Stone in the Farrington Action and, accordingly, Stone is no longer a party to the action.

NOTE 15 — EMPLOYEE BENEFIT PLANS:

We have entered into deferred compensation and disability agreements with certain of our officers and former officers whereby we have purchased split-dollar life insurance policies to provide certain retirement and death benefits for certain of our officers and former officers and death benefits payable to us. The aggregate death benefit of the policies was $460 at December 31, 2007, of which $325 was payable to certain officers or former officers or their beneficiaries and $135 was payable to us. Total cash surrender value of the policies, net of related surrender charges at December 31, 2007, was approximately $39 and is recorded in other assets. Additionally, the benefits under the deferred compensation agreements vest after certain periods of employment, and at December 31, 2007, the liability for such vested benefits was approximately $867 and is recorded in other long-term liabilities.

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

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

   In February 2005, our board of directors approved and adopted the Revised Annual Incentive Compensation Plan. In November 2007, our board of directors approved and adopted the Amended and Restated Revised Annual Incentive Compensation Plan. The revised plan provides for annual cash incentive bonuses that are tied to the achievement of certain strategic objectives as defined by our board of directors on an annual basis. Stone incurred expenses of $5,117, $4,356, and

$1,252, net of amounts capitalized, for each of the years ended December 31, 2007, 2006 and 2005, respectively, related to incentive compensation bonuses to be paid under the revised plan. A substantial portion of the 2006 annual incentive bonuses were not earned by performance but were a result of an employee retention program put in place by the board of directors to address employee uncertainty that resulted from two terminated merger agreements in 2006.

ii. The company's 2004 Amended and Restated Stock Incentive Plan (the "Plan") provides for the granting of incentive stock options, restricted stock awards, bonus stock awards, or any combination as is best suited to the circumstances of the particular employee or nonemployee director. The Plan provides for 4,225,000 shares of common stock to be reserved for issuance pursuant to this plan. Under the Plan, we may grant both incentive stock options qualifying under Section 422 of the Internal Revenue Code and options that are not qualified as incentive stock options to all employees and directors. All such options must have an exercise price of not less than the fair market value of the common stock on the date of grant and may not be re-priced without stockholder approval. Stock options to all employees vest ratably over a five-year service-vesting period and expire ten years subsequent to award. Stock options issued to non-employee directors vest ratably over a three-year service-vesting period and expire ten years subsequent to award. In addition, the Plan provides that shares available under the Plan may be granted as restricted stock. Restricted stock grants vest in two or more years at the discretion of the Compensation Committee of the board of directors. At December 31, 2007, we had approximately 965,122 additional shares available for issuance pursuant to the Plan.

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, 2007, 2006 and 2005, Stone contributed $870, $964 and $974, respectively, to the plan.

iv. The Stone Energy Corporation Deferred Compensation Plan provides eligible executives with the option to defer up to 100% of their compensation for a calendar year and we may, at our discretion, match a portion or all of the participant's deferral based upon a percentage determined by the board of directors. To date there have been no matching contributions made by Stone. The amounts held under the plan are invested in various investment funds maintained by a third party in accordance with the direction of each participant. At December 31, 2007 and 2006, plan assets of $3,782 and $2,153, respectively, were included in other assets. An equal amount of plan liabilities were included in other long-term liabilities.

v. On December 7, 2007, our board of directors approved and adopted the Stone Energy Corporation Executive Change of Control and Severance Plan ("Severance Plan"), as amended and restated to comply with the final regulations under Section 409A of the Internal Revenue Code and to provide that said plan will remain in force and effect unless and until terminated by the board. The Severance Plan amended and restated the company's previous Executive Change of Control and Severance Plan dated November 16, 2006.The Plan will provide the company's executives that are terminated in the event of a change of control and upon certain other terminations of employment with change of control and severance benefits as defined in the Severance Plan. The Severance Plan covers all officers, other than those covered by the company's Executive Change in Control Severance Policy (currently only the Chief Executive Officer and Chief Financial Officer). Severance is triggered by a termination of employment by the company for the "convenience of the company", as determined by the compensation committee of the board, whether or not a change of control has occurred. On and during the 12 month period following a change of control, a termination of the executive other than for cause or a resignation for "good reason" is deemed to be for the convenience of the company. Executives who are terminated within the scope of the Severance Plan will be entitled to certain payments and benefits including the following: a lump sum equal to his annual pay (or 2.99 times his annual pay if the termination is on or after a change of control), a pro-rated portion of the projected bonus, if any, for the year of termination or change of control, continued health plan coverage for six months and outplacement services. If the payments would be "excess parachute payments," they will be reduced as necessary to avoid the 20% excise tax under Section 4999 of the Internal Revenue Code (the "Code") but only if the executive is in a better net after-tax position after such reduction. Also, if a payment would be to a "key employee" for purposes of Section 409A of the Code, payment will be delayed until six months after his termination if required to comply with Section 409A. Benefits paid upon a change of control, without regard to whether there is a termination of employment, include the following: lapse of restrictions on restricted stock, accelerated vesting and cash-out of all in-the-money stock options, a 401(k) plan employer matching contribution at the rate of 50%, and a pro-rated portion of the projected bonus, if any, for the year of change of control.

On December 7, 2007, our board of directors approved and adopted the Stone Energy Corporation Employee Change of Control Severance Plan ("Employee Severance Plan"), as amended and restated to comply with the final regulations under Section 409A of the Internal Revenue Code and to provide that said plan will remain in force and effect unless and until terminated by the board. The Employee Severance Plan amended and restated the company's previous Employee Change of Control Severance Plan dated November 16, 2006. The Employee Severance Plan covers all full-time employees other than officers. Severance is triggered by an involuntary termination of employment on and during the 6 month period following a change of control, including a resignation by the employee relating to a change in duties. Employees who are terminated within the scope of the Employee Severance Plan will be entitled to certain payments and benefits including the following: a lump sum equal to (1) his weekly pay times his full years of service, plus (2) one week's pay for each full $10,000 of annual pay, but the sum of (1) and (2) cannot be less than 12 weeks of pay or greater than 52 weeks of pay; continued health plan coverage for six months; and a pro-rated portion of the employee's targeted bonus for the year. Benefits paid upon a change of control, without regard to whether there is a termination of employment, include the following: lapse of restrictions on restricted stock, accelerated vesting and cash-out of all in-the-money stock options, a 401(k) plan employer matching contribution at the rate of 50%, and a lump sum cash payment equal to the product of (i) the number of "restricted shares" of company stock that the employee would have received under the company's stock plan but did not receive for the time-vested portion of his long-term stock incentive award, if any, for the calendar year in which the change of control occurs times (ii) the price per share of the company's common stock utilized in effecting the change of control, provided that such amount shall be prorated by multiplying such amount by the number of full months that have elapsed from January 1 of that calendar year to the effective date of the change of control and then dividing the result by twelve (12).

NOTE 16 — OIL AND GAS RESERVE INFORMATION – UNAUDITED:

Our net proved oil and gas reserves at December 31, 2007 have been prepared in accordance with guidelines established by the SEC. Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates.

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

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

	Oil in MBbls	Natural Gas in MMcf	Oil and Natural Gas in MMcfe
Estimated proved reserves as of December 31, 2004	42,385	413,902	668,210
Revisions of previous estimates	(4,745)	(50,881)	(79,349)
Extensions, discoveries and other additions	6,534	34,492	73,696
Purchase of producing properties	2,173	704	13,743
Production	(4,838)	(54,129)	(83,158)
Estimated proved reserves as of December 31, 2005	41,509	344,088	593,142
Revisions of previous estimates	(5,064)	(43,241)	(73,625)
Extensions, discoveries and other additions	2,580	74,069	89,549
Purchase of producing properties	7,928	11,374	58,942
Production	(5,593)	(43,508)	(77,066)
Estimated proved reserves as of December 31, 2006	41,360	342,782	590,942
Revisions of previous estimates	4,584	27,183	54,688
Extensions, discoveries and other additions	1,635	20,765	30,573
Sale of reserves	(9,905)	(132,559)	(191,988)
Production	(6,088)	(45,088)	(81,617)
Estimated proved reserves as of December 31, 2007	31,586	213,083	402,598
Estimated proved developed reserves:			
as of December 31, 2005	31,557	241,347	430,689
as of December 31, 2006	33,301	222,664	422,470
as of December 31, 2007	25,172	171,815	322,846

The following tables present the standardized measure of future net cash flows related to estimated proved oil and gas reserves together with changes therein, as defined by the FASB, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2007 in accordance with SFAS No. 143. You should not assume that the future net cash flows or the discounted future net cash flows, referred to in the table below, represent the fair value of our estimated oil and gas reserves. As required by the SEC, we determine estimated future net cash flows using period-end market prices for oil and gas without considering hedge contracts in place at the end of the period. The average 2007 year-end product prices for all of our properties were $94.72 per barrel of oil and $7.25 per Mcf of gas. Future production and development costs are based on current costs with no escalations. Estimated future cash flows net of future income taxes have been discounted to their present values based on a 10% annual discount rate.

	Standardized Measure Year Ended December 31,		
	2007	2006	2005
Future cash inflows	$4,538,017	$4,199,788	$5,766,726
Future production costs	(915,166)	(1,254,374)	(1,293,950)
Future development costs	(842,040)	(966,627)	(678,212)
Future income taxes	(734,139)	(279,867)	(987,901)
Future net cash flows	2,046,672	1,698,920	2,806,663
10% annual discount	(525,083)	(450,090)	(873,684)
Standardized measure of discounted future net cash flows	$1,521,589	$1,248,830	$1,932,979

	Changes in Standardized Measure Year Ended December 31,		
	2007	2006	2005
Standardized measure at beginning of year	$1,248,830	$1,932,979	$1,612,459
Sales and transfers of oil and gas produced, net of production costs	(593,605)	(513,785)	(508,397)
Changes in price, net of future production costs	857,529	(931,742)	879,528
Extensions and discoveries, net of future production and development costs	114,729	120,314	269,742
Changes in estimated future development costs, net of development costs incurred during the period	(25,223)	(14,222)	(22,537)
Revisions of quantity estimates	363,783	(247,092)	(402,974)
Accretion of discount	142,605	256,508	207,148
Net change in income taxes	(338,336)	454,881	(173,079)
Purchases of reserves in-place	-	217,701	44,940
Sales of reserves in-place	(202,648)	-	-
Changes in production rates due to timing and other	(46,075)	(26,712)	26,150
Net increase (decrease) in standardized measure	272,759	(684,149)	320,521
Standardized measure at end of year	$1,521,589	$1,248,830	$1,932,980

NOTE 17 — SUMMARIZED QUARTERLY FINANCIAL INFORMATION – UNAUDITED:

	Three Months Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
2007				
Operating revenue	$173,333	$199,891	$178,412	$201,616
Income from operations	25,549	117,125*	52,616	90,250
Net income	10,476	71,983*	34,068	64,909
Earnings common per share	$0.38	$2.61	$1.23	$2.34
Earnings common per share assuming dilution	0.38	2.60	1.23	2.33
2006				
Operating revenue	$158,434	$169,179	$182,158	$179,217
Income (loss) from operations	42,018	45,140	29,099	(481,506)**
Net income (loss)	24,008	(1,452)	21,758	(298,536)**
Earnings (loss) common per share	$0.88	($0.05)	$0.79	($10.91)
Earnings (loss) common per share assuming dilution	0.88	(0.05)	0.79	(10.91)

* Includes a gain on sale of properties of $59,825 before taxes, $40,143 after taxes.

** Includes a ceiling test write-down of $510,013 before taxes, $330,488 after taxes.

GLOSSARY OF CERTAIN INDUSTRY TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this Form 10-K. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(-4) of Regulation S-X. The entire definitions of those terms can be viewed on the website at *http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas*.

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

BBtu. One billion Btus.

Bcf. One billion cubic feet of gas.

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

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

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

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

Exploratory well. A well drilled to find and produce oil or gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

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

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

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

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

Mcf. One thousand cubic feet of gas.

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

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

MMBtu. One million Btus.

MMcf. One million cubic feet of gas.

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

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

Make-Whole Amount. The greater of 104.125% of the principal amount of the 8¼% Notes (103.375% of the principal amount of the 63/4% Notes)and the sum of the present values of the remaining scheduled payments of principal and interest discounted to the date of redemption on a semiannual basis at the applicable treasury rate plus 50 basis points.

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

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

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

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

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

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

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities 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. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

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

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

EXHIBIT INDEX

Exhibit Number	Description
3.1	-- Certificate of Incorporation of the Registrant, as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).
3.2	-- Certificate of Amendment of the Certificate of Incorporation of Stone Energy Corporation, dated February 1, 2001 (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K, filed February 7, 2001).
3.3	-- Restated Bylaws of the Registrant (incorporated by reference to Exhibit 3.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 001-12074)).
4.1	-- Rights Agreement, with exhibits A, B and C thereto, dated as of October 15, 1998, between Stone Energy Corporation and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A (File No. 001-12074)).
4.2	-- Amendment No. 1, dated as of October 28, 2000, to Rights Agreement dated as of October 15, 1998, between Stone Energy Corporation and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-4 (Registration No. 333-51968)).
4.3	-- Indenture between Stone Energy Corporation and JPMorgan Chase Bank dated December 10, 2001 (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-4 (Registration No. 333-81380)).
4.4	-- Indenture between Stone Energy Corporation and JPMorgan Chase Bank, National Association, as trustee, dated December 15, 2004 (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on December 15, 2004.)
†10.1	-- Deferred Compensation and Disability Agreement between TSPC and E. J. Louviere dated July 16, 1981 (incorporated by reference to Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1995 (File No. 001-12074)).
†10.2	-- Stone Energy Corporation 2004 Amended and Restated Stock Incentive Plan (incorporated by reference to the Registrant's Registration Statement on Form S-8 (Registration No. 333-107440)).
†10.3	-- Stone Energy Corporation Revised (2005) Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.11 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-12074)).
10.4	-- Letter Agreement dated May 19, 2005 between Stone Energy Corporation and Kenneth H. Beer (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed May 24, 2005 (File No. 001-12074)).
10.5	-- Employment Agreement dated January 12, 2006 between Stone Energy Corporation and David H. Welch (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed January 18, 2006 (File No. 001-12074)).
†10.6	-- Stone Energy Corporation Deferred Compensation Plan (incorporated by reference to Exhibit 4.5 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-12074)).
†10.7	-- Adoption Agreement between Fidelity Management Trust Company and Stone Energy Corporation for the Stone Energy Corporation Deferred Compensation Plan dated December 1, 2004 (incorporated by reference to Exhibit 4.6 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-12074)).
10.8	-- Letter Agreement dated June 28, 2007 between Stone Energy Corporation and Richard L. Smith (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K dated June 28, 2007 (File No. 001-12074)).

10.9 -- Credit Agreement between Stone Energy Corporation, the financial institutions named therein and Bank of America N.A., as administrative agent, dated November 1, 2007 (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K dated November 1, 2007 (File No. 001-12074)).

*10.10 -- Stone Energy Corporation Amended and Restated Revised Annual Incentive Compensation Plan (dated November 14, 2007).

10.11 -- Stone Energy Corporation Executive Change of Control and Severance Plan (as amended and restated) dated December 7, 2007 (incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K, filed December 12, 2007 (File No. 001-12074)).

10.12 -- Stone Energy Corporation Employee Change of Control Severance Plan (as amended and restated) dated December 7, 2007 (incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K, filed December 12, 2007 (File No. 001-12074)).

10.13 -- Stone Energy Corporation Executive Change in Control Severance Policy (as amended and restated) dated December 7, 2007 (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed December 12, 2007 (File No. 001-12074)).

*21.1 -- Subsidiaries of the Registrant.

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

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

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

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

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

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* Filed herewith.

† Identifies management contracts and compensatory plans or arrangements.

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

Exhibit 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

I, David H. Welch, certify that:

1. I have reviewed this Annual Report on Form 10-K of Stone Energy Corporation;

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

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

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

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiary, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 27, 2008

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

Exhibit 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER

I, Kenneth H. Beer, certify that:

1. I have reviewed this Annual Report on Form 10-K of Stone Energy Corporation;

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

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

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

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiary, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 27, 2008

/s/ Kenneth H. Beer
Kenneth H. Beer
Senior Vice President and Chief Financial Officer

Corporate Information

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www.StoneEnergy.com

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NYSE: SGY

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3900 One Shell Square
701 Poydras Street
New Orleans, Louisiana
70139-9869

Annual Meeting
The Company's Annual Meeting of Stockholders will be held at 10:00 a.m. on May 15, 2008 at the Windsor Court Hotel, New Orleans, Louisiana.

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

Transfer Agent and Registrar
Mellon Investor Services LLC
480 Washington Boulevard
Jersey City, New Jersey 07310
(800) 635-9270
www.melloninvestor.com/isd

Annual CEO Certification
The Annual CEO Certification regarding the New York Stock Exchange's corporate governance listing standards required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual was provided to the New York Stock Exchange on May 24, 2007.

Stone Energy Employees

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