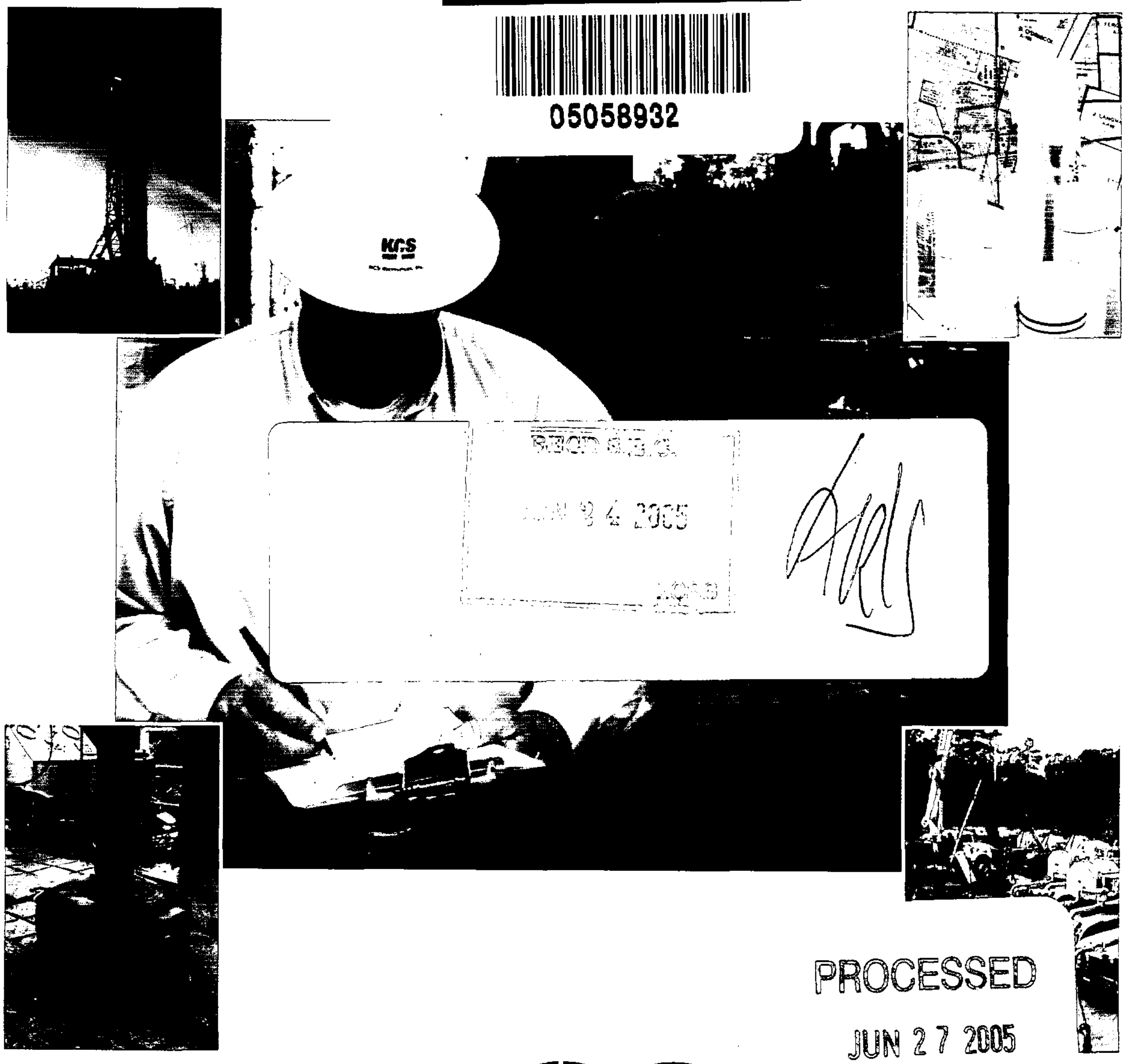
Annual Report 2004



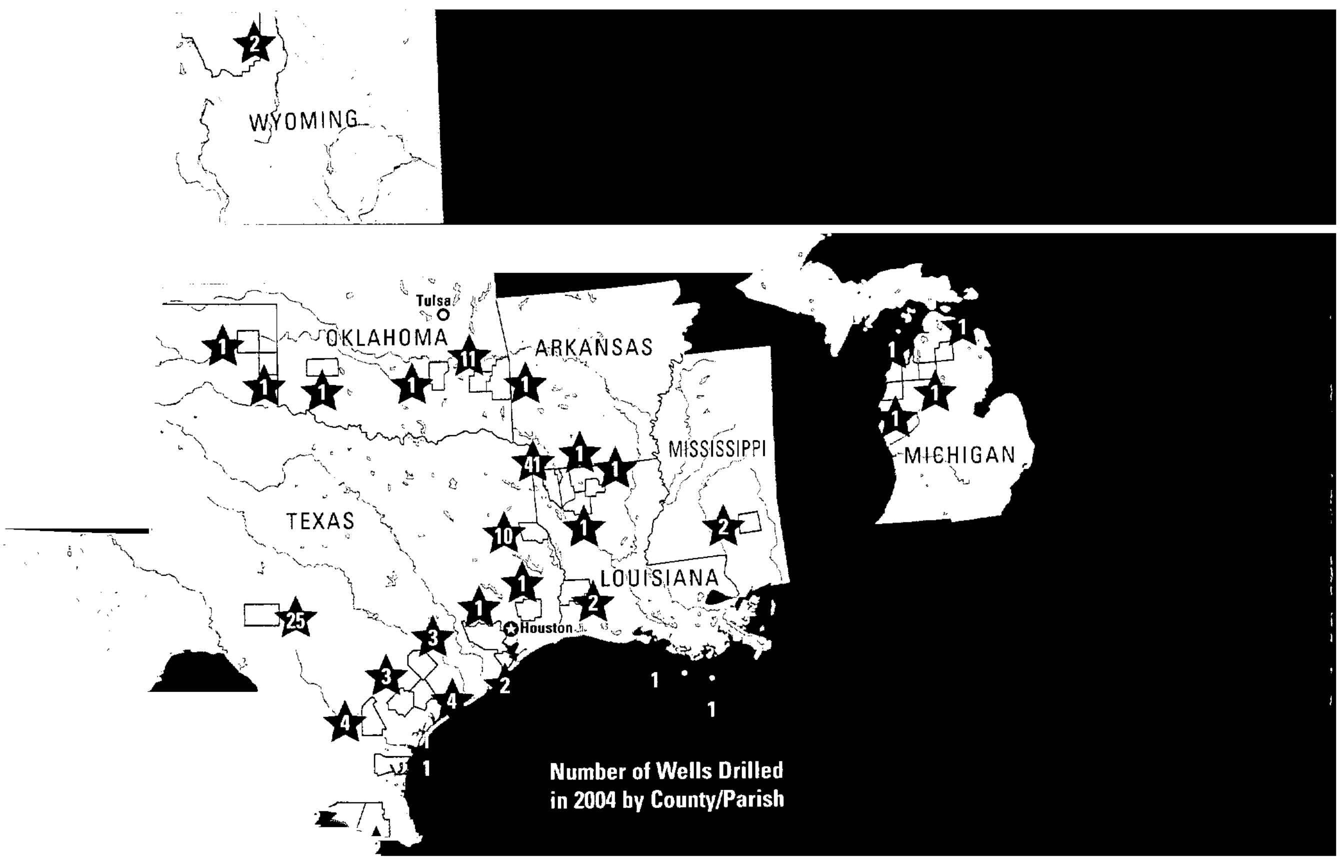
KCS

KCS Energy, Inc.

KCS Energy, Inc. is an independent energy company engaged in the acquisition, exploration and production of natural gas and crude oil with operations focused in the Mid-Continent and Gulf Coast regions of the United States.

2004 was a record year for the Company:

- Net income - $100 million
- Number of wells drilled - 130 with a 97% success rate
- Cash flow from operating activities - $134 million
- Increased proved reserves 22% to 328 Bcfe
- Increased net production by 25%
- Issued $175 million 7-1/8% Senior Notes due 2012, redeemed 8-7/8% notes due 2006
- Closed year with stock price up 40% from end of 2003



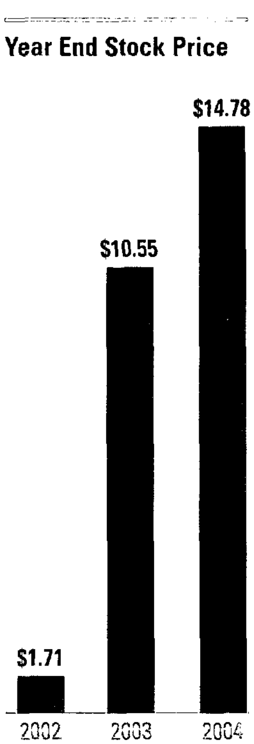
Number of Wells Drilled in 2004 by County/Parish

To Our Shareholders:

I am pleased to report that 2004 was one of the most successful years in KCS' history, both operationally and financially. We drilled a record 130 wells with a record 97% success rate. This resulted in a 22% increase in our oil and gas reserves and a 25% increase in our net production. Our double-digit growth in reserves and production, combined with higher commodity prices and continued cost control, produced record net income, record cash flow and a 40% increase in our stock price for the year, following the 517% increase in 2003.

We started the year with several key goals. Key among these was expanding our drilling efforts to increase our reserves and production, further enhancing our financial flexibility and the continuing reduction of debt per Mcfe. We accomplished these goals and much more. The end result can be seen in our operating and financial performance as well as in the significant inventory of drilling locations in existing properties and several new prospects which should provide our Company with ongoing growth for years to come.

We began the year with a $105 million capital expenditure budget. This budget was increased several times, ultimately to $167 million, based on strong cash flow from the successful drilling program and solid commodity prices. Over the last three years, we have drilled 261 wells with an overall 91% success rate and added 223 Bcfe of new reserves, while producing a total of 89 Bcfe of our reserves. We ended 2004 with 328 Bcfe with a PV-10 value of $814 million using December 31 prices held constant. This compares to 268 Bcfe with a PV-10 value of $630 million at the end of 2003.



James W. Christmas
Chairman and
Chief Executive Officer

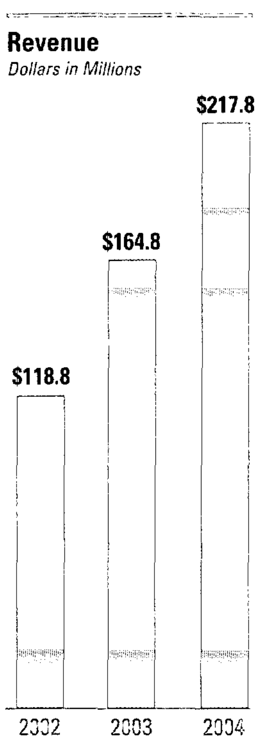
"Double-digit growth in reserves and production ... produced record net income, record cash flow and a 40% increase in our stock price."

Financial Results

Our average realized price per Mcfe increased 19% to $5.47. This coupled with a significant increase in production led to revenues of $217 million, a 32% increase. Excluding production and other taxes that vary with commodity prices, our cash operating and administrative costs per Mcfe increased just $0.01 to $0.95, despite significant additional expenses incurred in connection with the new Sarbanes-Oxley regulatory requirements. Our DD&A unit costs rose $0.05 to $1.43 per Mcfe, and interest costs were reduced from $0.60 in 2003 to $0.36 per Mcfe.

Operating income increased 49% to $104 million, while net income increased 46% to a record $100.4 million which includes the impact of a reduction in the valuation allowance against our deferred tax assets resulting from the significant improvement in the Company's earnings and outlook. I encourage you to read Management's Discussion and Analysis on page 28 of the Form 10-K report included as part of this annual report for more information about our financial results.

We took advantage of the favorable interest rate environment to issue $175 million of new 7 1/8% Senior Notes due 2012 and redeemed the old 8 7/8% notes due 2006. Our debt to capitalization ratio, which was over 100% a couple of years ago, was 46% at year end and our debt per Mcfe of reserves has improved markedly from $0.95 in 2002 to $0.53 at the end of 2004.



133 Employees at KCS contributed to a drilling program of 130 wells in 2004.

Strategy

Our strategy going forward is simple, a repeat of what we executed in 2004. We plan to focus on low-risk development and exploitation drilling in our core operating areas. We will commit approximately 15% of our capital expenditure budget to moderate risk, higher potential exploration activities, primarily in the on-shore Gulf Coast area. At the same time, we plan to maintain a conservative capital structure and continue to reduce debt per Mcfe by increasing our oil and gas reserve base. While commodity prices are better today than they were in 2004, and are expected to continue to be strong, we will continue our disciplined hedging program. It is designed to protect against price declines while participating to a large extent in future price increases. In this way, we endeavor to ensure that we protect a sufficient level of cash flow to carry out a capital expenditure program sufficient to replace our expected production and still benefit if prices rise.

2004 was a record year of drilling for KCS with 130 new wells, of which 97% were successful.

Summary and Outlook

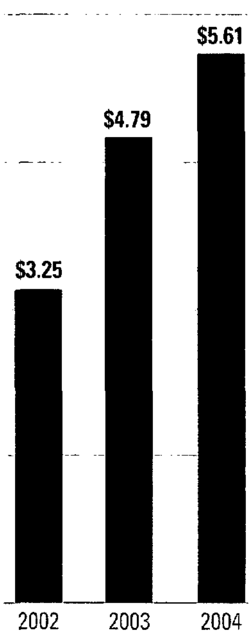
KCS enjoys a strong financial position and we have significant financial flexibility to capitalize on growth opportunities.

Looking forward, we have initially budgeted $190 million for our 2005 capital expenditure program, which we believe can be funded primarily through cash flow. We plan to drill more than 150 wells which we believe will enable us to significantly grow our oil and gas reserves. We continue to focus on adding reserves and production in our core areas, and further reducing our costs per Mcfe in order to enhance profitability. With a talented, dedicated and motivated group of employees, we are truly excited about the future.

I want to thank our shareholders for your continued support, our employees for their loyalty and dedication and our Board of Directors for their guidance and support.

James W. Christmas
Chairman and Chief Executive Officer
April 11, 2005

Net Realized Gas Price



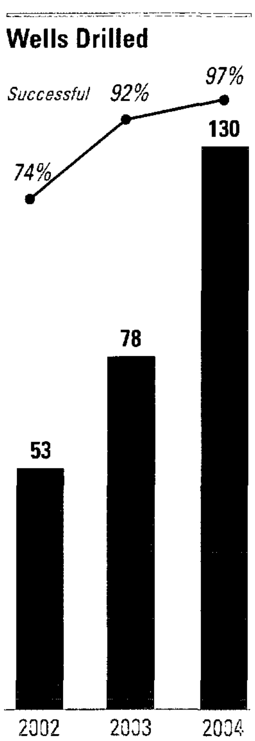
Operations Review

KCS has been successful over the last several years in significantly growing production and reserves "organically" – finding accumulations of natural gas and oil by drilling new wells to new reservoirs.

In 2004 the Company drilled a record 130 wells resulting in a 25% increase in net production. The increase in production combined with a 19% increase in net realized commodity prices greatly increased cash flow for the year.

In 2005 we plan to use the rising cash flow to again increase our capital budget and drill even more new wells.

We plan to concentrate our drilling program in core areas: South Texas and North Louisiana where we continue to benefit from drilling where we have distinct familiarity of the formations and economics. We specialize in drilling and producing thick, tight gas reservoirs in which our geological and engineering staff have comprehensive knowledge. Most of the wells we drill require massive hydraulic fracturing to stimulate the gas filled rock. Because of our considerable ongoing drilling program, we have been able to obtain operating efficiencies which lower our per unit costs and contribute to higher profit margins.



"KCS drilled 261 wells over the last three years with a 91% success rate."

Our oil and gas reserves have continued to grow over the last several years. In 2003 we added 94 Bcfe of new reserves and in 2004 we added another 90 Bcfe. Over this two year period we produced approximately 63 Bcfe of our reserves.

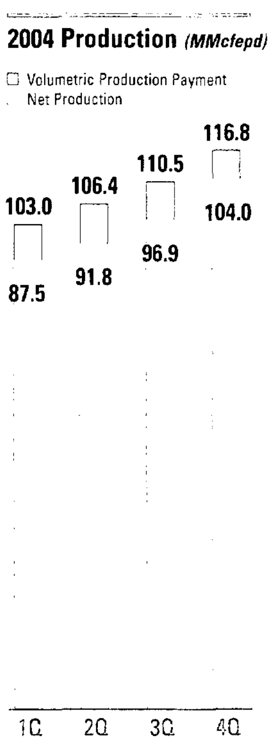
Our goals for 2005 are two-fold: 1) grow production and reserves; 2) add new prospects and acreage primarily in our core areas to allow continued future drilling and growth.

We expect that drilling and operating costs will continue to rise in 2005 however; even at flat commodity prices our profit margins should remain robust.

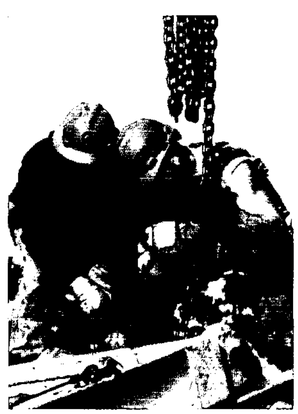
In 2005, as in 2004, our staff will focus its efforts in the following key fields and areas:

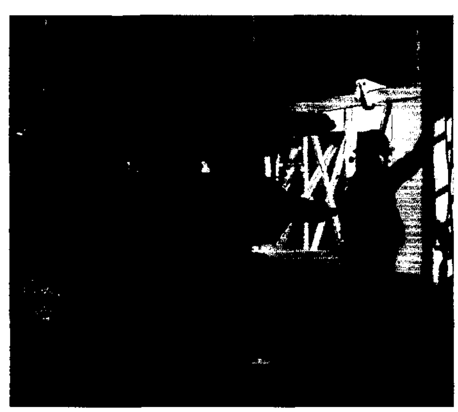
Elm Grove Field, North Louisiana

The Company's largest field is located in Bossier Parish Louisiana. This field contributes approximately 25% of our production and accounts for 35% of our net oil and gas reserves. We drilled 41 wells in the field in 2004, primarily targeting Cotton Valley reservoirs. The impact of the work was significant, increasing gross operated production from approximately 30 MMcfepd at



"We specialize in drilling and producing thick, tight gas reservoirs in which our geological and engineering staff have comprehensive knowledge."





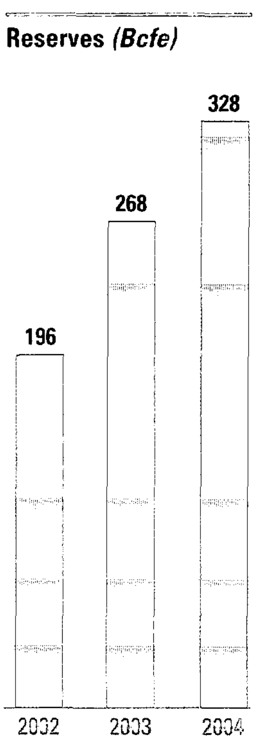
the beginning of the year to over 45 MMcfepd by year end. In 2005 we plan to keep three rigs active in the field, drilling 45-50 additional wells.

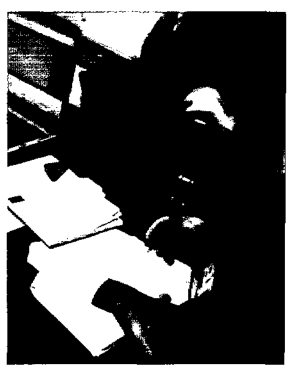
Sawyer Canyon Field, West Texas

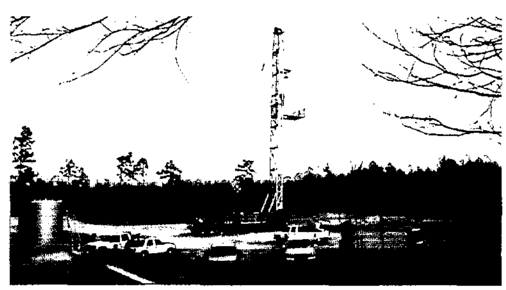
Our second largest field located in Sutton County, Texas produces from shallow Canyon Sandstone reservoirs. In 2004 we drilled 25 wells and anticipate drilling another 20-25 wells in 2005. These are generally shallow, lower cost wells which have a high degree of success finding production to replace field declines.

Other Mid-Continent Fields

Three other Mid-Continent fields have multi-well programs planned for 2005. Since January of 2003, KCS has drilled 17 wells in the Joaquin Field located in Shelby County, East Texas. In 2004 we increased our leasehold position by approximately 50% and plan to drill at least 10 wells in 2005. After drilling seven wells in 2004 in the Talihina field located in Latimer County, Oklahoma; we expect 5-10 more wells in 2005. And in the Terryville field in Lincoln Parish of North Louisiana we also anticipate 5-10 wells in 2005. These three fields should provide extensional and infill drilling locations for years to come.





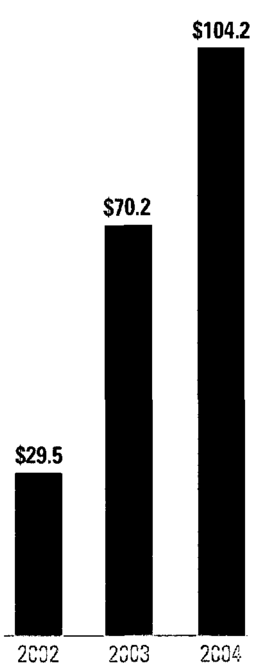


Gulf Coast Activity

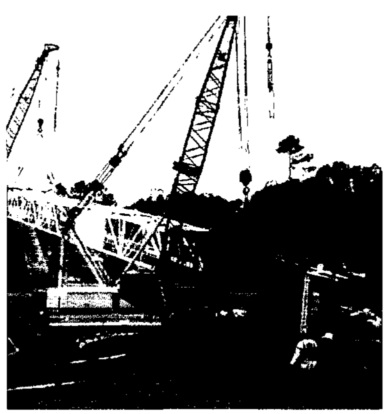
We drilled a record 29 wells in the Gulf Coast in 2004. Thirteen of these wells were exploration wells providing more significant upside potential for the Company. Three of the more exciting areas included the La Reforma Field, West Mission Valley area and Coquat Field, all located in South Texas. At La Reforma we completed four Vicksburg wells and anticipate another three to four in 2005. In the West Mission Valley area, we participated in seven Wilcox wells and are planning for a similar program in 2005. In the new Coquat Field, the Company had four exploration discoveries in 2004 and we plan to drill another four to five wells in 2005. We also took a major step in 2004 acquiring leases in the O'Connor Ranch Field in Goliad County, South Texas; a play which extends from our success in adjacent fields. We plan to drill over 20 wells on this new acreage this year.

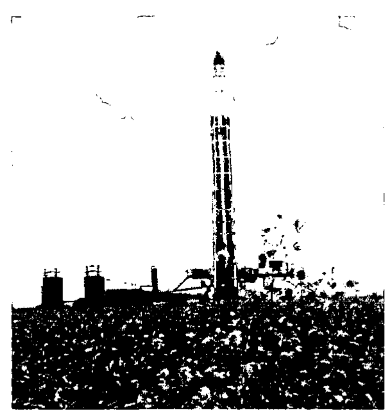
We've set an initial capital spending budget of $190 million for 2005 and expect to drill over 150 wells this year. Approximately three fourths of our capital program will be committed to low risk, Mid-Continent drilling and one fourth to the Gulf Coast. About 15% of our capital budget is dedicated to exploration to further grow the Company. In 2005, we again expect to continue drilling in our core areas that have proven successful to increase production, reserves and shareholders' value.

Operating Income
Dollars in Millions



"Our goals for 2005: 1) grow production and reserves; 2) add new prospects and acreage primarily in our core areas to allow continued future drilling."

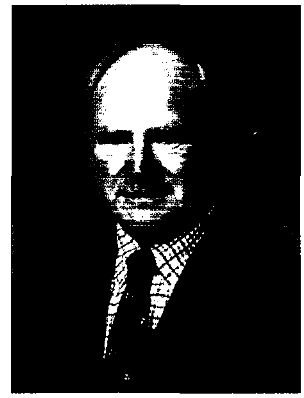




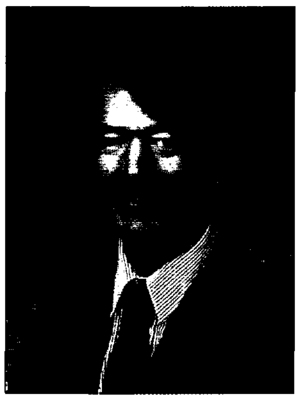
Directors & Officers

James W. Christmas[3]
Chairman and
Chief Executive Officer

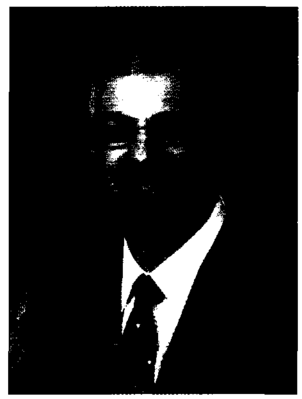
William N. Hahne
President,
Chief Operating Officer
and Director



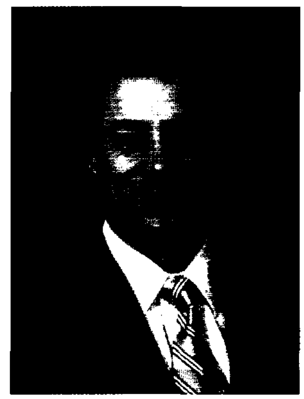
G. Stanton Geary[2,4]
Proprietor,
Gemini Associates
Venture Capital Consulting Firm



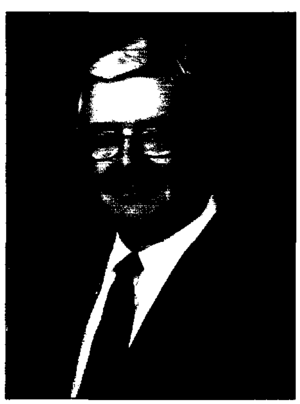
Robert G. Raynolds, PhD[1,2,3,5]
Independent Consulting
Geologist



Joel D. Siegel[1,3,4]
President,
Orloff, Lowenbach,
Stifelman & Siegel, P.A.
Attorneys-at-Law



Christopher A. Viggiano[1,2,4]
President and Chairman,
O'Bryan Glass Corporation
Specialty Glass Manufacturer



Harry Lee Stout
Senior Vice President,
Marketing and
Risk Management

Joseph T. Leary
Vice President and
Chief Financial Officer

Frederick Dwyer
Vice President,
Controller and Secretary

[1] *Member Compensation Committee*
[2] *Member Audit Committee*
[3] *Member Executive Committee*
[4] *Member Nominating and Corporate Governance Committee*
[5] *Lead Outside Director*

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

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2004

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 001-13781

KCS Energy, Inc.

(Exact name of registrant as specified in its charter)

SEC MAIL RECEIVED PROCESSING JUN 2 2005 SECTION

Delaware	**22-2889587**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5555 San Felipe Road, Suite 1200, Houston, Texas	**77056**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code: (713) 877-8006

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 $0.01 per share	New York Stock Exchange

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. 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 registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

The aggregate market value of the 46,513,928 shares of the registrant's common stock, par value $0.01 per share, held by non-affiliates of the registrant at the $13.32 closing price on June 30, 2004 (the last business day of the registrant's most recently completed second fiscal quarter) was $619,565,521.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☐ No ☐

Not applicable. Although the registrant was involved in bankruptcy proceedings during the preceding five years, the registrant did not distribute securities under its plan of reorganization.

The number of shares of the registrant's common stock, par value $0.01 per share, outstanding as of the close of business on March 10, 2005: 49,777,229.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement for the Annual Meeting of Stockholders to be held on May 26, 2005 are incorporated by reference into Part III of this annual report on Form 10-K. Except with respect to information specifically incorporated by reference in this Form 10-K, the Proxy Statement for the Annual Meeting of Stockholders is not deemed to be filed as part hereof.

TABLE OF CONTENTS

Quantities of natural gas are expressed in this annual report on Form 10-K in terms of thousand cubic feet (Mcf), million cubic feet (MMcf) or billion cubic feet (Bcf). Natural gas sales volumes and amounts hedged under derivative contracts may be expressed in terms of one million British thermal units (MMBtu), which is equal to one Mcf containing 1,000 British thermal units (Btu) per cubic foot. The average Btu content of our natural gas reserves is in excess of 1,000 Btu per cubic foot. Oil and natural gas liquids are quantified in terms of barrels (bbls) and thousands of barrels (Mbbls). Oil and natural gas liquids are compared with natural gas in terms of thousand cubic feet equivalent (Mcfe), million cubic feet equivalent (MMcfe) and billion cubic feet equivalent (Bcfe). For purposes of comparing oil and natural gas liquids to natural gas on a per unit equivalent basis, one barrel of oil or natural gas liquids is the energy equivalent of six Mcf of natural gas. With respect to information relating to our working interest in wells or acreage, "net" oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest in the oil and gas wells or acreage. Unless otherwise specified, all references to wells and acres are gross. Working interest, or "WI", is the net percentage ownership interest in a well that gives the owner the right to drill, produce and conduct operating activities on the property and a share of the production.

References to "proved reserves" in this annual report on Form 10-K refer to 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. The term "proved developed reserves" refers to reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. The term "proved undeveloped reserves" refers to 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. The term "recompletion" refers to the completion for production of an existing wellbore in another formation from that in which the well has previously been completed. The term "productive well" refers to a well that is producing oil or natural gas or that is capable of production. The term "workover" refers to operations on a producing well to restore or increase production from an existing formation or recomplete to a new formation.

This annual report on Form 10-K refers to the pre-tax present value of estimated future net revenues, or "PV-10 value," of our oil and natural gas reserves. The PV-10 value of reserves refers to the pre-tax present value of estimated future net revenues, computed by applying year-end prices to estimated future production from the reserves, deducting estimated future expenditures, and applying a discount factor of 10%. In accordance with applicable requirements of the Securities and Exchange Commission, the PV-10 value is generally based on prices and costs as of the date of the estimate. In contrast, the actual future prices and costs may be materially higher or lower. Please do not interpret the PV-10 values as the current market value of our properties' estimated oil and natural gas reserves. The standardized measure of discounted future net cash flows, or "Standardized Measure", differs from PV-10 value because Standardized Measure includes the present value effect of future income taxes.

PART I

Item 1. *Business.*

General

KCS Energy, Inc., a Delaware corporation, is an independent oil and gas company engaged in the acquisition, exploration, development and production of natural gas and crude oil. Our properties are primarily located in the Mid-Continent and onshore Gulf Coast regions of the United States. We also have interests in producing properties in Michigan, California, Wyoming and offshore Gulf of Mexico. As of December 31, 2004, our oil and natural gas properties were estimated to have net proved reserves of approximately 328 Bcfe with a PV-10 value of $814 million. Approximately 88% of our net proved reserve base was natural gas and approximately 76% was classified as proved developed. We operate approximately 84% of our proved oil and natural gas reserve base. The following table sets forth the estimated quantities of proved reserves attributable to our principal operating regions as of December 31, 2004.

	Estimated Proved Reserves			
	Natural Gas (MMcf)	Oil (Mbbls)	Total (MMcfe)	Percent of Reserves
Mid-Continent Region(1)	224,251	2,784	240,953	74%
Gulf Coast Region(2)	63,667	3,826	86,626	26%
Total Company	287,918	6,610	327,579	100%

(1) Includes Michigan and Wyoming

(2) Includes California

In 2004, we produced an average of 109.2 MMcfe per day compared to 95.2 MMcfe per day in 2003. We plan to continue growing our reserves and production through a balanced investment program in low-risk exploitation activities in the Mid-Continent and Gulf Coast regions and moderate-risk, higher potential exploration drilling programs primarily in the onshore Gulf Coast region.

We are a publicly-owned company whose stock is traded on the New York Stock Exchange under the symbol "KCS." We were incorporated in Delaware in 1988 in connection with the spin-off of the non-utility businesses of a New Jersey-based natural gas distribution company. Our principal executive offices are located at 5555 San Felipe Road, Suite 1200, Houston, Texas 77056. Our telephone number is (713) 877-8006. Unless the context otherwise requires, the terms "KCS," "we," "our" or "us" refer to KCS Energy, Inc. and its subsidiaries.

2004 Highlights

The year ended December 31, 2004 was an outstanding year for us. We drilled a record 130 wells during 2004, of which 126 were completed, resulting in a 97% success rate and significantly increased production and reserves. In 2004, gross production increased 15%, to 40 Bcfe, while net production after production payment delivery obligations, that do not contribute to cash flow from operating activities, increased 25% compared to 2003. Natural gas and oil reserves increased 22% to 328 Bcfe as of December 31, 2004 compared to 268 Bcfe as of December 31, 2003. In total, we added 94.5 Bcfe of proved reserves during 2004, of which 97% was through the drill bit. Total oil and gas capital expenditures were $166.7 million.

In 2004, we continued to execute our strategies of focusing on low-risk development and exploitation drilling in our core operating areas and to commit approximately 15% of our capital expenditure budget to moderate-risk, higher-potential exploration prospects primarily in the onshore Gulf Coast region. In 2005, we plan to commit approximately 15% to 20% of our capital expenditure budget to such exploration projects. We continue to focus primarily on natural gas prospects. We have continued our disciplined hedging program designed to protect against price declines while participating to a large extent in future price increases. In this way, we endeavor to ensure that we generate a sufficient level of cash flow to carry out a capital expenditure program sufficient to at least replace our expected production and still benefit if prices rise.

We further strengthened our financial condition in 2004 and provided additional financial flexibility by completing a $175 million senior notes offering. The new senior notes bear interest at an annual rate of 7⅛% and mature in 2012. The proceeds of this issuance were used to redeem our $125 million 8⅞% senior subordinated notes due 2006, including an early redemption premium, and to repay the $22 million outstanding under our bank credit facility. As of December 31, 2004, we had $6.6 million of cash on hand and $100 million of unused committed borrowing capacity under our bank credit facility. We plan to maintain a conservative capital structure. Please read Note 6 to our Consolidated Financial Statements for more information regarding our senior notes and our bank credit facility.

We believe that the steps taken during 2004, along with our multi-year drilling prospect inventory, position us to increase production and reserves in 2005 and beyond.

Competitive Strengths and Business Strategies

We intend to continue to increase production and reserves to optimize stockholder value by executing the following strategies:

- *Focus on Natural Gas* — As of December 31, 2004, our proved reserves were 88% natural gas. We believe that the future need for natural gas in the United States will continue to grow and that natural gas is better insulated from the price volatility associated with global geopolitical instability. In addition, North American supplies of natural gas have been declining in recent years. Lease operating expenses associated with natural gas properties are also typically less than oil properties, which allows us to maintain our low per-unit cost structure.

- *Grow Through the Drill Bit* — We believe our personnel possess exceptional knowledge in identifying, drilling and stimulating tight rock formations. We also think that the economics of drilling self-generated prospects are superior to those of acquiring reserves. Over the last three years, we have added 217 Bcfe to our reserves, of which 95% were through the drill bit. With our inventory of drilling prospects, we believe that we are well-positioned to continue growing our reserves and production.

- *Exploit Our Large Inventory of Drilling Projects* — We have a significant inventory of future drilling locations in targeted areas. Generally, these locations range in depth from 5,000 feet to 13,000 feet and are low risk opportunities. Most of the locations are step-out or extension wells from existing production.

- *Concentrate in Core Areas* — We concentrate our drilling programs predominately in the Mid-Continent and Gulf Coast regions. Operating in concentrated areas helps us to better control our overhead by enabling us to manage a greater amount of acreage with fewer employees and minimize incremental costs of increased drilling and production. Our strategy of targeting our operations in relatively concentrated areas permits us to more efficiently capitalize on our base of geological, engineering, exploration, development, completion and production experience in these regions. The areas we produce generally have high price realizations relative to benchmark prices for natural gas production and favorable operating costs.

- *Control Drilling and Production Operations* — We operate approximately 84% of our proved oil and natural gas reserve base as of December 31, 2004. We prefer to generate and retain operating control over our own prospects rather than owning non-operated interests. This allows us to more effectively control operating costs, the timing and plans for future development, the level of drilling and the marketing of production on the properties. In addition, as an operator, we receive reimbursements for overhead from other working interest owners, which reduces our general and administrative expenses. During the year ended December 31, 2004, we controlled the drilling operations on 93 of the 130 wells in which we participated.

- *Search for Complimentary Acquisitions* — We proactively search for acquisitions in our core areas to expand our acreage position and drilling inventory. Two recent examples of this were the O'Connor Ranch acreage acquisition in the third quarter of 2004 that compliments our south Texas drilling program and our recently announced acquisition of properties in our North-Louisiana-East Texas core operating area. Please read Note 15 to our Consolidated Financial Statements for more information regarding our recently announced acquisition which is currently scheduled to close in mid-April 2005.
- *Employ Experienced Technical Professionals* — We employ oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers, production and reservoir engineers and landmen who have an average of approximately 25 years of experience in their technical fields. We continually apply our extensive in-house expertise and advanced technologies to benefit our drilling and completion operations.
- *Maintain Financial Flexibility* — The timing of most of our capital expenditures is discretionary. Consequently, we have a significant degree of flexibility to adjust the level of expenditures according to market conditions. We currently anticipate spending approximately $190 million, exclusive of acquisitions, on capital projects in 2005. We expect that these projects will be funded primarily with internally generated cash flow.
- *Control Risk* — We allocate approximately 80% of our capital on an annual basis to low risk development and exploitation projects and the remainder to moderate risk exploration plays. We set limits on the amount of capital we will invest in any one exploration project. We hedge a portion of our oil and natural gas to protect against downward price swings, and we control costs closely to ensure the best possible profit margins. In addition, we turnkey our drilling operations where economic in order to reduce drilling risk.

Core Operating Areas

Mid-Continent

In the Mid-Continent region, we concentrate our drilling programs primarily in north Louisiana, east Texas, Oklahoma (Anadarko and Arkoma basins) and west Texas. Our Mid-Continent operations provide us with a solid base for production and reserve growth. We plan to continue to exploit areas within the various basins that require low-risk exploitation wells for additional reservoir drainage. Our exploitation wells are generally step-out and extension type wells with moderate reserve potential. During 2004, we drilled 101 wells in this region with a success rate of 97%. In 2005, we plan to drill 90 to 115 wells in this region, approximately half of which are planned in the Elm Grove Field which is our largest field. We will also pursue drilling in the Sawyer Canyon, Joaquin, Terryville and Talihina fields and have budgeted $20 million to commence development of the properties being acquired in April 2005.

- *Elm Grove Field* — Located in Bossier Parish of north Louisiana, production from this field comes from the Hosston and Cotton Valley formations. These zones are composed of low permeability rocks that require large fracture stimulation treatments to produce. We operate nine sections with WI ranging from 89 to 100%. We also have lesser interests ranging from 5% to 82% in six other adjacent sections. In 2004, the field contributed about 26% of our net production. As of December 31, 2004, we had 116 Bcfe of proved reserves in this field that accounted for approximately 38% of our PV-10 value.

  We began a development program in late 2002 that included the drilling of six wells. In 2003, we drilled 19 wells and in 2004 41 additional wells, all of which were successful. This drilling activity increased gross operated production from 6 MMcfe per day in 2002 to over 45 MMcfe per day as of December 31, 2004. In 2005, we plan to drill 45 to 50 proved undeveloped and step-out locations to continue growing production and reserves.
- *Sawyer Canyon Field* — Our second largest field, contributing approximately 11% of our net production in 2004, is located in Sutton County, west Texas. We are actively producing and developing on lands comprising approximately 33,500 acres. Over the last several years, we have been conducting drilling programs targeting shallow Canyon sandstone formations. We have a 92% to 100% WI in most

of the areas we are actively drilling. We drilled 25 wells in 2004 and plan to drill approximately 20 to 30 additional wells in 2005.

- *Joaquin Field* — We operate and have rights to approximately 8,200 acres in this property located just west of the Texas-Louisiana border in Shelby County, Texas which produce Travis Peak sands at depths of 6,000 to 8,600 feet. In 2004, we drilled nine wells in this field and anticipate drilling approximately ten additional wells in 2005.

- *Terryville Field* — We have 5,160 acres in this developing play. We recently drilled our third well to test the potential of the Cotton Valley sands in this area. We have preliminarily budgeted seven wells for the acreage in 2005 which could lead to a future multi-well development program of the acreage.

Gulf Coast

In the Gulf Coast region, we concentrate our drilling programs primarily in south Texas. We also have working interests in several minor non-operated offshore and Mississippi salt basin properties. We conduct development programs and pursue moderate-risk, higher potential exploration drilling programs in this region. Our Gulf Coast operations have numerous exploration prospects that are expected to provide us additional growth. During 2004, we drilled 13 exploration and 16 development wells in this region with a success rate of 97%. We anticipate drilling 40 to 50 wells in this region in 2005, approximately three-fourths of which will be exploratory. In 2004, exploration success was achieved in the La Reforma and Coquat fields. In the third quarter of 2004, we acquired a 42,300 acre lease on the O'Connor Ranch and license to approximately 100 square miles of 3D seismic data in Goliad County, Texas. The 2005 drilling program will be concentrated in O'Connor Ranch, La Reforma, Coquat and Austin fields and the West Mission Valley area.

Wilcox Trend — Our projects in the Wilcox trend are mostly located in Harris, Goliad, Victoria and Live Oak counties in Texas. Our primary objectives are the abnormally pressured Middle Wilcox sands, although we also produce from normal-pressured Frio, Yegua and Upper Wilcox zones. Sandstones in these formations are found at depths between 4,000 to 13,000 feet. In 2004, we drilled five Wilcox exploration wells, all of which were successful. In addition, we drilled seven Wilcox development wells. Normally, we generate these prospects and retain a 25% to 60% WI. Over the last several years we have been expanding our efforts in this area. In 2001, we purchased interests in the West Mission Valley Field and participated in the discovery of the Marshall Field. In 2003, we participated in discoveries at the Five Mile Creek Field and the East Marshall Field. In 2004, we participated in the following areas:

- *West Mission Valley Area, Goliad and Victoria Counties, Texas.* We drilled seven Wilcox wells in 2004, four of which we operated, with WI ranging from 25% to 50%. Reservoirs are mid-Wilcox in age and are at moderate depth ranges of 10,000 to 12,000 feet. We plan to drill an additional nine Wilcox wells in this area in 2005.

- *Coquat Field, Live Oak County, Texas.* We drilled four successful wells in 2004 in this KCS-operated field with WI ranging from 40% to 57%. The drilling program increased our gross field production from less than 1 MMcfepd to over 21 MMcfepd. Four to five wells are scheduled for drilling in Coquat in 2005, one of these, the Meider #7A, has been drilled and is completing now. All of the productive zones are abnormally pressured Wilcox reservoirs from 10,000 to 13,000 feet.

- *O'Connor Ranch, Goliad County, Texas.* In the third quarter of 2004, we purchased 42,300 acres with accompanying 100 miles of 3D seismic data in this KCS-operated field where our WI ranges from 55% to 95%. This property is located immediately south and adjacent to West Mission Valley. It is also contiguous to our production area in the Austin Field. In 2005, we plan to drill 15 to 20 Frio wells at depths ranging of 3,000 to 4,000 feet. We also plan to drill Yegua prospects at depths approximating 7,000 feet and Wilcox prospects at depths ranging from 12,000 to 14,500 feet.

Vicksburg Trend — We also pursue Vicksburg formation prospects primarily in our La Reforma Field in Hidalgo County, Texas. We drilled a successful initial test well in late 2002, drilled one additional well in 2003 and four wells in 2004. Since beginning this drilling program we have increased gross production in this field from below 5 MMcfpd to over 50 MMcfepd in 2004. We plan on drilling three to four additional wells in the La Reforma Field in 2005. Our WI in these wells is either 24% or 31.5% depending on the well's location.

Other Gulf Coast — We have minor, non-operated working interests in several offshore blocks and in several fields in the Mississippi salt basin.

Other Operating Areas

We also operate and own majority interests in fields located in the Niagran Reef play of Michigan, several fields in Wyoming and one field in the Los Angeles basin in California. As of December 31, 2004, these properties accounted for approximately 10% of our PV-10 value. In 2004, we drilled four wells in Michigan and participated in two development wells in a Wyoming unit.

Oil and Gas Properties

We hold interests in all of our oil and gas properties through two operating subsidiaries: KCS Resources, Inc., a Delaware corporation, and Medallion California Properties Company, a Texas corporation. The oil and gas properties referred to in this annual report on Form 10-K are held by these subsidiaries. We treat all operations as one line of business.

The following table sets forth the number of gross and net producing wells by region as of December 31, 2004.

	Producing Wells							
	Natural Gas				Oil			
	Operated		Non-operated		Operated		Non-operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent Region(1)	608	561.5	264	32.2	53	43.1	34	3.7
Gulf Coast Region(2)	102	72.4	155	28.9	41	34.7	23	3.7
Total Company	710	633.9	419	61.1	94	77.8	57	7.4

(1) Includes Michigan and Wyoming

(2) Includes California

Oil and Natural Gas Reserves

The following table sets forth, as of December 31, 2004, summary information with respect to estimates of our proved oil and natural gas reserves based on year-end prices. Oil and natural gas prices as of December 31, 2004 are not necessarily indicative of the prices that we expect to receive in the future. Accordingly, the pre-tax present value of future net revenues in the following table should not be construed to be the current market value of the estimated oil and natural gas reserves.

	As of December 31, 2004				
	Natural Gas (MMcf)	Oil (Mbbls)	Total (MMcfe)	Future Net Revenues ($000)	PV-10 Value ($000)
Proved developed reserves	213,174	5,764	247,761	$1,082,464	$654,896
Proved undeveloped reserves	74,744	846	79,818	$ 299,516	$158,911
Proved reserves	287,918	6,610	327,579	$1,381,980	$813,807

In accordance with Securities and Exchange Commission guidelines, the estimates of future net revenues from our proved reserves and the present values of our proved reserves are made using oil and natural gas sales prices in effect as of the dates of those estimates and are held constant throughout the life of the properties except where those guidelines permit alternate treatment. Natural gas prices are based on either a contract price or a December 31, 2004 spot price of $6.18 per MMBtu, adjusted by lease for Btu content, transportation fees and regional price differentials. Oil prices are based on a December 31, 2004 West Texas Intermediate posted price of $40.25 per barrel, adjusted by lease for gravity, transportation fees and regional price differentials. The prices for natural gas and oil are subject to substantial seasonal fluctuations, and prices for each are subject to substantial fluctuations as a result of numerous other factors. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Business — Risk Factors" for further discussion of these and other factors.

The estimates of our proved oil and natural gas reserves and associated revenues, as of December 31, 2004, were prepared by us and were audited by Netherland Sewell & Associates, Inc., or NSAI. NSAI follows the general principles set forth in the standards pertaining to the estimating and auditing of oil and gas reserve information promulgated by the Society of Petroleum Engineers, or SPE.

A reserve audit as defined by the SPE is not the same as a financial audit. The SPE's definition of a reserve audit includes the following concepts:

- A reserve audit is an examination of reserve information that is conducted for the purpose of expressing an opinion as to whether such reserve information, in the aggregate, is reasonable and has been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.

- The estimation of reserves is an imprecise science due to the many unknown geologic and reservoir factors that can only be estimated through sampling techniques. Since reserves are only estimates, they cannot be audited for the purpose of verifying exactness. Instead, reserve information is audited for the purpose of reviewing in sufficient detail the policies, procedures and methods used by a company in estimating its reserves so that the reserve auditors may express an opinion as to whether, in the aggregate, the reserve information furnished by the company is reasonable and has been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.

- The methods and procedures used by a company, and the reserve information furnished by the company, must be reviewed in sufficient detail to permit the reserve auditor, in its professional judgment, to express an opinion as to the reasonableness of the reserve information. In some cases, the auditing procedure may require the reserve auditor to prepare its own estimates of reserve information for particular properties. The desirability of preparing its own estimates is determined by the reserve auditor exercising its professional judgment.

In performing our reserve audit, NSAI does prepare its own estimates of reserves for the majority our properties. As part of the audit process, we and NSAI compare our reserve estimates, and often share additional data in order to understand and narrow the gaps on properties where there are major variances in the estimates. Once NSAI is satisfied that the reserve estimates are reasonable and that their audit objectives have been met, the process is deemed complete. When compared on a well-by-well or lease-by-lease basis, some of our estimates of net proved reserves are greater and some are less than the estimates of NSAI. We have been advised by NSAI that it generally issues a completed audit opinion if its reserve estimates are within ten percent of a company's reserve estimates. At the conclusion of the audit process, it is NSAI's opinion, as set forth in its audit letter, that our estimates of our proved oil and natural gas reserves and associated future net revenues are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles.

Production

The following table presents certain information with respect to production attributable to our properties including average sales prices and unit costs for the years ended December 31, 2004, 2003 and 2002.

	Year Ended December 31,		
	2004	2003	2002
Production: (a)			
Natural gas (MMcf)	33,905	28,166	29,672
Oil (Mbbl)	795	838	1,003
Natural gas liquids (Mbbl)	216	258	288
Total (MMcfe)	39,971	34,741	37,417
Summary (MMcfe)			
Working interest (b)	39,971	34,741	34,959
Purchased VPP (c)	—	—	2,458
Total	39,971	34,741	37,417
Dedicated to Production Payment	(5,170)	(6,807)	(11,196)
Net Production	34,801	27,934	26,221
Average Price:			
Natural gas (per Mcf)	$ 5.61	$ 4.79	$ 3.25
Oil (per bbl)	30.53	25.34	20.52
Natural gas liquids (per bbl)	19.07	14.58	10.05
Total (per Mcfe) (d)	$ 5.47	$ 4.60	$ 3.21
Average production cost (per Mcfe) (c):			
Lease operating expense	$ 0.72	$ 0.71	$ 0.65
Production and other taxes	0.35	0.29	0.23
Total	$ 1.07	$ 1.00	$ 0.88

(a) Includes delivery obligations dedicated to a production payment transaction whereby in February 2001 we sold 43.1 Bcfe (38.3 Bcf of natural gas and 797 Mbbl of oil) to be delivered over 60 months (the "Production Payment'). Production includes 5,170 MMcfe in 2004, 6,807 MMcfe in 2003 and 11,196 MMcfe in 2002 dedicated to the Production Payment. Please read Note 1 to our Consolidated Financial Statements for more information on the Production Payment.

(b) We sold properties in 2002 to reduce debt.

(c) We discontinued making new investments in VPPs in 1999 and final deliveries from our VPP program were received in November 2002. The average production cost per Mcfe in 2002 excludes the production received under our purchased VPP program because that production was free from these expenses.

(d) The average realized prices reported above include the non-cash effects of volumes delivered under the Production Payment as well as the unwinding of various derivative contracts terminated in 2001. These items do not generate cash to fund our operations. Excluding these items, the average realized price per Mcfe was $5.85, $5.05 and $3.19 in 2004, 2003 and 2002, respectively. For further information, please read "Management's Discussion and Analysis of Financial Condition and Results of Operation — Major Influences on Results of Operations."

Acreage

The following table sets forth our developed and undeveloped leased acreage as of December 31, 2004. The leases in which we have an interest are for varying primary terms, and many require the payment of delay rentals to continue the primary term. The operator may surrender the leases at any time by notices to the lessors, the cessation of production, fulfillment of commitments, or failure to make timely payments of delay rentals.

State	Developed Acres Gross	Developed Acres Net	Undeveloped Acres Gross	Undeveloped Acres Net
Texas	99,652	61,132	72,516	58,654
Louisiana	26,788	19,467	15,271	13,281
Oklahoma	44,603	26,452	10,390	7,142
Michigan	9,182	4,795	1,904	866
Wyoming	25,351	20,330	6,010	2,854
Offshore	80,063	9,683	—	—
Other	9,016	5,676	5,467	1,454
Total	294,655	147,535	111,558	84,251

Title to Interests

We believe that title to the various interests set forth above is satisfactory and consistent with the standards generally accepted in the oil and gas industry, subject only to immaterial exceptions that do not detract substantially from the value of the interests or materially interfere with their use in our operations. Our owned interests may be subject to one or more royalty, overriding royalty and other outstanding interests customary in the industry. The interests may additionally be subject to obligations or duties under applicable laws, ordinances, rules, regulations and orders of arbitral or governmental authorities. In addition, the interests may be subject to burdens, including production payments, net profits interests, development obligations under oil and gas leases and other encumbrances, easements and restrictions.

Drilling Activities

During the three-year period ended December 31, 2004, we participated in drilling 261 (169.2 net) wells with a success rate of 91%. During 2004, we participated in drilling 130 (91.7 net) wells with a success rate of 97%. Our drilling results for 2004 include 115 development wells and 15 exploration wells with success rates of 98% and 87%, respectively. All of our drilling activities are conducted through arrangements with independent contractors. The following table sets forth certain information with respect to our drilling activities during the years ended December 31, 2004, 2003 and 2002.

	Year Ended December 31,					
	2004		2003		2002	
Type of Well	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	8	1.9	—	—	1	0.8
Natural gas	105	82.8	66	49.3	28	13.4
Non-productive	2	0.8	5	2.9	5	1.2
Total	115	85.5	71	52.2	34	15.4
Exploratory:						
Oil	—	—	—	—	—	—
Natural gas	13	5.0	6	2.7	10	4.5
Non-productive	2	1.2	1	0.5	9	2.2
Total	15	6.2	7	3.2	19	6.7

As of December 31, 2004, we were participating in the drilling of eight (3.9 net) wells.

Other Facilities

Our principal executive offices and those of our operating subsidiaries are leased in modern office buildings in Houston, Texas and Tulsa, Oklahoma.

We believe that all of our property, plant and equipment are well maintained, in good operating condition and suitable for the purposes for which they are used.

Regulation

General. Our business is affected by numerous laws and regulations, including energy, environmental, conservation, tax and other laws and regulations relating to the energy industry. Changes in any of these laws and regulations could have a material adverse effect on our business. In light of the many uncertainties related to current and future laws and regulations, including their applicability to us, we may be unable to predict the overall effect of current and future laws and regulations on our future operations.

We believe that our operations comply in all material respects with all applicable laws and regulations. Although applicable laws and regulations have a substantial impact upon the energy industry, generally these laws and regulations do not appear to affect us any differently, or to any greater or lesser extent, than other similar companies in the energy industry. The following discussion describes certain laws and regulations applicable to the energy industry and is qualified in its entirety by the foregoing.

State Regulations Affecting Production Operations. Our onshore exploration, production and exploitation activities are subject to regulation at the state level. Laws and regulations vary from state to state, but generally include laws to regulate drilling and production activities and to promote resource conservation. Examples of these state laws and regulations include laws that:

- require permits and bonds to drill and operate wells;
- regulate the method of drilling and casing wells;
- establish surface use and restoration requirements for properties upon which wells are drilled;
- regulate plugging and abandonment of wells;
- regulate the disposal of fluids used or produced in connection with operations;
- regulate the location of wells, including establishing the minimum size of drilling units and the minimum spacing between wells;
- concern unitization or pooling of oil and natural gas properties;
- establish maximum rates of production from oil and natural gas wells; and
- restrict the venting or flaring of natural gas.

These laws and regulations may adversely affect the profitability of affected properties or our operations. We are unable to predict the future cost or impact of complying with these regulations.

Federal Regulations Affecting Production Operations. We also operate federal oil and natural gas leases that are subject to the regulation of the United States Bureau of Land Management, or BLM, and the United States Minerals Management Service, or MMS. Leases regulated by the BLM and MMS contain relatively standardized terms requiring compliance with detailed regulations and orders. These regulations specify, for example, lease operating, safety and conservation standards, well plugging and abandonment requirements, and surface restoration requirements. In addition, the BLM and MMS generally require us to post surety bonds or other acceptable financial assurances to assure that our obligations will be met. The cost of these bonds or other financial assurances can be substantial and we may be unable to obtain bonds or other financial assurances in all cases. Under certain circumstances, the BLM or MMS may require operations on federal leases to be suspended or terminated. Any suspension or termination under these leases may adversely affect our interests.

Additional proposals and proceedings that might affect the oil and natural gas industry are pending before Congress, the Federal Energy Regulatory Commission, or FERC, the MMS, the BLM, state commissions and the courts. We are unable to predict when or whether any such proposals may become effective. Historically, the natural gas industry has been very heavily regulated and for many years was subject to price controls imposed by the federal government. The current regulatory approach pursued by various agencies and Congress may not continue indefinitely and it is possible Congress (or in the case of some natural gas sales, the FERC) could reimpose price controls in the future. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon our capital expenditures, earnings or competitive position.

Operating Hazards and Environmental Matters. The oil and natural gas business involves a variety of operating risks, including the risk of fires, natural disasters, explosions, well blowouts, adverse weather conditions, mechanical problems, including pipe failure, abnormally pressured formations, and environmental accidents, including oil spills, natural gas leaks or ruptures, and discharges of toxic gases or other pollutants. The occurrence of these risks could result in substantial losses to us due to personal injury, loss of life, damage to or destruction of wells, production facilities, natural resources or other property or equipment, pollution and other environmental damage. These occurrences could also subject us to clean-up obligations, regulatory investigation, penalties or suspension of operations. Although we believe we are adequately insured, these hazards may hinder or delay drilling, development and production operations.

Oil and natural gas operations are subject to extensive federal, state and local laws and regulations that regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. These laws and regulations may:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment;
- restrict drilling activities on certain lands, including wetlands or other protected areas; and
- impose substantial liabilities for pollution resulting from drilling and production operations.

Failure to comply with these laws and regulations may also result in civil and criminal fines and penalties.

Our properties, and any wastes spilled or disposed of by us, may be subject to federal or state environmental laws that could require us to remove the wastes or remediate contamination. For example, the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the "Superfund" law, imposes liability, without regard to fault or the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the present or former owner or operator of the disposal site or sites where the release occurred and companies that disposed, or arranged for the disposal, of the hazardous substances. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances, for damages to natural resources and for the costs of certain health studies. In addition, neighboring landowners and other third parties may assert claims for personal injury and property damage allegedly caused by the release of hazardous substances.

Our operations may also be subject to the Clean Air Act, or CAA, and comparable state and local requirements. Pursuant to these requirements, we may be required to incur certain capital expenditures for air pollution control equipment in connection with maintaining or obtaining permits and approvals relating to air emissions. We do not believe that our operations will be materially adversely affected by these requirements.

In addition, the United States Oil Pollution Act, or OPA, requires owners and operators of facilities in or near rivers, creeks, wetlands, coastal waters, offshore waters, and other United States waters to adopt and implement plans and procedures to prevent oil spills. OPA also requires affected facility owners and operators in coastal waters to demonstrate that they have at least $10 million in financial resources to pay for the costs of the remediation of an oil spill and compensating any parties damaged by an oil spill. These financial assurances may be increased to as much as $150 million depending on a facility's worst case oil spill discharge volume and other relative operational, environmental and human health risks.

Our operations are also subject to the federal Clean Water Act, or CWA, and analogous state laws. Among other matters, these laws may prohibit the discharge of waters produced in association with hydrocarbons into coastal waters. To comply with this prohibition, we may be required to incur capital expenditures or increased operating expenses. The CWA also regulates discharges of storm water runoff. This program requires covered facilities to obtain individual permits, participate in a group permit or seek coverage under a general permit. While certain of our properties may require permits for discharges of storm water runoff, we believe that we will be able to obtain, or be included under, these permits as necessary. Coverage under these permits may require us to make minor modifications to existing facilities and operations that would not have a material adverse effect on us.

Pursuant to the Safe Drinking Water Act, underground injection control, or UIC, wells, including wells used in enhanced recovery and disposal operations associated with oil and natural gas exploration and production activities, are subject to regulation. These regulations include permitting, bonding, operating, maintenance and reporting requirements.

In addition, the disposal of wastes containing naturally occurring radioactive material, which is commonly encountered during oil and natural gas production, is regulated under state law. Typically, wastes containing naturally occurring radioactive material can be managed on-site or disposed of at facilities licensed to receive such waste at costs that are not expected to be material.

Risk Factors

The oil and natural gas market is volatile and the price of oil and natural gas fluctuates, which may adversely affect our cash flows and the value of our oil and natural gas reserves.

Our future revenues and profits and the value of our oil and natural gas reserves will depend substantially on the demand and prices we receive for produced oil and natural gas. Oil and natural gas prices have been and are likely to continue to be volatile in the future. The recent oil and natural gas prices may not continue and could drop precipitously in a short period of time. The prices of oil and natural gas are subject to wide fluctuations in response to a variety of factors beyond our control, including the following:

- relatively minor changes in the supply of, and demand for, domestic and foreign oil and natural gas;
- market uncertainty;
- the ability of members of the Organization of Petroleum Exporting Countries to agree upon and maintain oil prices and production controls;
- the level of consumer product demand;
- political conditions in international oil-producing regions, such as the Middle East, Nigeria and Venezuela;
- weather conditions;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- overall domestic and global economic conditions;
- the price of oil and natural gas imports;
- the effect of worldwide energy conservation measures; and
- the proximity to and capacity of transportation facilities.

These external factors and the volatile nature of the energy markets make it difficult to reliably estimate future prices of oil and natural gas.

As oil and natural gas prices decline, we are affected in several ways:

- we are paid less for our oil and natural gas, thereby reducing our cash flows;
- exploration and development activity may decline as some projects may become uneconomic and either are delayed or eliminated;
- our lenders could reduce the borrowing base under our bank credit facility because of lower oil and natural gas reserve values, thereby reducing our liquidity and possibly requiring mandatory loan repayments; and
- access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable in a low price environment.

Accordingly, any substantial or extended decline in oil or natural gas prices may have material adverse effects on our cash flow, liquidity and profitability and may cause us to be unable to meet our financial obligations or make planned capital expenditures.

We may be unable to satisfy our future capital requirements.

We make substantial capital expenditures in connection with the acquisition, exploration and development of our oil and natural gas properties. In the past, we have funded these capital expenditures with cash flow from operations, funds from long-term debt financings, including bank financings secured by our oil and natural gas assets, and funds from equity financings. Our future cash flows are subject to a number of factors, some of which are beyond our control, including the following:

- the price of oil and natural gas;
- the level of production from existing wells;
- operating and development costs; and
- our success in locating and producing new reserves.

The availability of long-term debt and equity financing is also subject to these factors. Investors in our debt securities view our future cash flow as a measure of our ability to make principal and interest payments. In addition, the availability of funds under our bank credit facility is based on the value of our estimated oil and natural gas reserves and our cash flows, which in turn are based on prices of oil and natural gas and the amount and timing of production. Similarly, investors in our equity securities consider both the value of our oil and natural gas properties and our cash flow in evaluating our prospects for growth and profitability. If our future cash flows decrease, however, and we are unable to obtain additional long-term debt or equity financing or our borrowing base under our bank credit facility is re-determined to a lower amount, we may be unable to satisfy our future capital requirements.

We may be unable to successfully identify, execute or effectively integrate future acquisitions, which may negatively affect our results of operations.

Acquisitions of oil and natural gas businesses and properties have been an important element of our business, and we will continue to pursue acquisitions in the future. In the last several years, we have pursued and consummated acquisitions that allow us to drill development and extension wells. Although we regularly engage in discussions with, and submit proposals to, acquisition candidates, suitable acquisitions may not be available in the future on reasonable terms as there is intense competition for acquisition opportunities in our industry. If we do identify an appropriate acquisition candidate, we may be unable to successfully negotiate the terms of an acquisition, finance the acquisition or, if the acquisition occurs, effectively integrate the acquired business into our existing business. Negotiations of potential acquisitions and the integration of acquired business operations may require a disproportionate amount of management's attention and our resources. Even if we complete additional acquisitions, continued acquisition financing may not be available or available on reasonable terms, any new businesses may not generate revenues comparable to our existing business, the anticipated cost efficiencies or synergies may not be realized and these businesses may not be integrated successfully or operated profitably. The success of any acquisition will depend on a number of factors, many of which are beyond our control, including:

- the ability to estimate accurately the recoverable volumes of reserves;
- the ability to estimate accurately rates of future production and future net revenues attainable from the reserves;
- future oil and natural gas prices;
- operating costs; and
- the ability to estimate accurately potential environmental and other liabilities.

Our inability to successfully identify, execute or effectively integrate future acquisitions may negatively affect our results of operations. Even though we perform a due diligence review (including a review of title and other records) of the major properties we seek to acquire that we believe is consistent with industry practices, these reviews are inherently incomplete. It is generally not feasible for us to review in-depth every individual property and all records involved in each acquisition. However, even an in-depth review of records and properties may not necessarily reveal existing or potential problems or permit us to become familiar enough with the properties to assess fully their deficiencies and potential. Even when problems are identified, we may not be able to obtain contractual indemnities from the sellers for liabilities that it created and we may assume certain environmental and other risks and liabilities in connection with the acquired businesses and properties. The discovery of any material liabilities associated with our acquisitions could harm our results of operations.

In addition, acquisitions of businesses may require additional debt or equity financing, resulting in additional leverage or dilution of ownership. Our bank credit facility and the indenture governing our senior notes contain certain covenants that limit, or which may have the effect of limiting, among other things, acquisitions, capital expenditures, the sale of assets and the incurrence of additional indebtedness.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and future net revenues.

The quantities and values of our proved reserves included in this annual report and in the other documents we file with, or furnish to, the Securities and Exchange Commission are only estimates and are subject to numerous uncertainties. Reserve estimating is a subjective process of determining the size of underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net revenues may vary considerably from the actual results because of a number of variable factors and assumptions involved. These include:

- the effects of regulation by governmental agencies;
- future oil and natural gas prices;
- operating costs;
- the method by which the reservoir is produced as well as the properties of the rock;
- relationships with landowners, working interest partners, pipeline companies and others;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

In addition, volumetric calculations are often used to estimate initial reserves from a field. These estimates utilize data including the area that a well is expected to drain, rock properties derived from log analysis, anticipated reservoir fluid properties, abandonment pressure and estimates of recovery factors. As production data becomes available, the actual performance is often used to project the final reserves. As such, initial reserve estimates are much less precise in nature. The actual production, revenues and expenditures related to our reserves may vary materially from the engineers' estimates.

Furthermore, we may make changes to our estimates of reserves and future net revenues. These changes, which may be material, may be based on the following factors:

- well performance;
- results of development including drilling and workovers;
- oil and natural gas prices;
- performance of counterparties under agreements to which we are a party; and
- operating and development costs.

Actual future net revenues may also be materially affected by the following factors:

- the amount and timing of actual production and costs incurred with such production;
- the supply of, and demand for, oil and natural gas; and
- the changes in governmental regulations or taxation.

Ultimately, the timing in producing and the costs incurred in developing and producing will affect the actual present value of oil and natural gas. In addition, the Securities and Exchange Commission requires that we apply a 10% discount factor in calculating PV-10 value for reporting purposes. This may not be the most appropriate discount factor to apply because it does not take into account the interest rates in effect, the risks associated with us and our properties, or the oil and natural gas industry in general.

For the foregoing reasons, you should not assume that the present value of future net cash flows from our proved reserves referred to in this annual report or in our other reports filed with, or furnished to, the Securities and Exchange Commission is the current market value of our estimated oil and natural gas reserves. In accordance with Securities and Exchange Commission requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual prices and costs since the date of the estimate and future prices and costs may differ materially from those used in the net present value estimate, and as a result, net present value estimates using current prices and costs may be significantly more or less than the estimate which is provided in this annual report or in our other reports filed with, or furnished to, the Securities and Exchange Commission.

Our operating activities involve significant risks that are inherent in the oil and natural gas industry, which may result in substantial losses, and insurance may be unavailable or inadequate to protect us against these risks.

Our operations are subject to numerous operating risks that are beyond our control, are inherent in the oil and natural gas industry and could result in substantial losses. These risks include:

- fires;
- natural disasters;
- explosions;
- well blowouts;
- adverse weather conditions;
- mechanical problems, including pipe failure;
- abnormally pressured formations; and
- environmental accidents, including oil spills, natural gas leaks or ruptures, or other discharges of toxic gases or other pollutants.

The occurrence of these risks could result in substantial losses due to personal injury, loss of life, damage to or destruction of wells, production facilities, natural resources or other property or equipment, pollution and other environmental damage. These occurrences could also subject us to clean-up obligations, regulatory investigation, penalties or suspension of operations. Further, our operations may be materially curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- the presence of unanticipated pressure or irregularities in formations;
- equipment failures or accidents;
- title problems;
- weather conditions;
- compliance with governmental requirements; and
- costs of, shortages or delays in the availability of, drilling rigs or in the delivery of equipment and experienced labor.

In accordance with customary industry practice, we maintain insurance against some, but not all, of the risks described above. The levels of insurance we maintain may not be adequate to fully cover any losses or liabilities. We may not be able to maintain insurance at commercially acceptable premium levels or at all. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse effect on our financial condition and operations.

We may be unable to produce sufficient amounts of oil and natural gas and, as a result, our profitability and cash flow will decline.

We may drill new wells that are not productive or we may not recover all or any portion of our investment. Drilling for oil and natural gas may be unprofitable due to a number of risks, including:

- wells may not be productive, either because commercially productive reservoirs were not encountered or for other reasons;
- wells that are productive may not provide sufficient net reserves to return a profit after taking into account leasehold, geophysical and geological, drilling, operating and other costs; and
- the costs of drilling, completing and operating wells are often uncertain.

If we are unable to produce sufficient amounts of oil and natural gas, our profitability and cash flow will decline.

If we are unable to acquire or discover additional reserves, our reserves and production will decline materially.

Our prospects for future growth and profitability depend primarily on our ability to replace oil and natural gas reserves through acquisitions and exploratory and development drilling. Acquisitions may not be available at attractive prices or at all. The decision to purchase, explore or develop a property depends in part on geophysical and geological analyses and engineering studies that are often inconclusive or subject to varying interpretations. As a consequence, our acquisition, exploration and development activities may not result in significant additional reserves or reserves that are economically recoverable. Without the acquisition, discovery or development of additional reserves, our proved reserves and production will decline materially.

Our failure to remain competitive with our numerous competitors, many of which have substantially greater resources than we do, could adversely affect our results of operations.

The oil and natural gas industry is highly competitive in the search for, and development and acquisition of, reserves and in the marketing of oil and natural gas production. We compete with major oil and natural gas companies, other independent oil and natural gas concerns and individual producers and operators in most aspects of our business, including the following:

- the acquisition of oil and natural gas businesses and properties;
- the exploration, development, production and marketing of oil and natural gas;
- the acquisition of properties and equipment; and
- the hiring and retention of personnel necessary to explore for, develop, produce and market oil and natural gas.

Many of these competitors have substantially greater financial and other resources than we do. If we are unable to successfully compete against our competitors, our business, prospects, financial condition and results of operations may be adversely affected.

We are subject to complex laws and regulations, including environmental regulations, that may adversely affect the cost, manner or feasibility of doing business.

Our business is subject to numerous federal, state and local laws and regulations, including energy, environmental, conservation, tax and other laws and regulations relating to the energy industry. Please read "— Regulation" above. We are subject to various federal, state and local laws and regulations relating to the discharge of materials into, and protection of, the environment. These laws and regulations may, among other things:

- limit drilling locations or the rate of allowable hydrocarbon production from a well;
- affect the cost, terms and availability of oil and natural gas transportation by pipeline;
- impose liability on us under an oil and natural gas lease for the cost of pollution clean-up and remediation resulting from operations;
- impose liability on us for personal injuries and property damage;
- subject us to liability for pollution damages, including oil spills, discharge of hazardous materials and reclamation costs; and
- require suspension or cessation of operations in affected areas and subject the lessee to administrative, civil and criminal penalties.

Any of these liabilities, penalties, suspensions, terminations or regulatory changes could make it more expensive for us to conduct our business or cause us to limit or curtail some of our operations.

Environmental laws have in recent years become more stringent and have generally sought to impose greater liability on a larger number of potentially responsible parties. While we are not currently aware of any situation involving an environmental claim that would likely have a material adverse effect on our business, it is always possible that an environmental claim with respect to one or more of our current properties or a business or property that one of our predecessors owned or used could arise and could involve the expenditure of a material amount of funds. Although we maintain insurance coverage which we believe is customary in the industry, we are not fully insured against all environmental risks.

The Department of Transportation, through the Office of Pipeline Safety and Research and Special Programs Administration, has implemented a series of rules requiring operators of natural gas and hazardous liquid pipelines to develop integrity management plans for pipelines that, in the event of failure, could impact certain high consequence areas. These rules also require operators to conduct baseline integrity assessments of all applicable pipeline segments located in the high consequence areas. We continually are in the process of identifying any of our pipeline segments that may be subject to these rules. We have developed an integrity management plan for all covered pipeline segments. We do not expect to incur significant costs in achieving compliance with these rules.

Further, hydrocarbon-producing states regulate conservation practices and the protection of correlative rights. These regulations affect our operations and limit the quantity of hydrocarbons we may produce and sell.

The oil and natural gas regulatory environment could change in ways that could substantially increase the cost of complying with the requirements of environmental and other regulations. We cannot predict whether, or when, new laws and regulations may be enacted or adopted, and we cannot predict the cost of compliance with changing laws and regulations or their effects on oil and natural gas use or prices.

We have limited control over the activities on properties that we do not operate, which could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

Although we operate most of the properties in which we have an interest, other companies operate some of the properties. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund for their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the number of wells we drill, realization of our targeted returns or lead to unexpected future costs.

The concentration of our customers in the energy industry could increase our exposure to credit risk, which could result in losses.

The concentration of our customers in the energy industry may impact our overall exposure to credit risk, either positively or negatively, in that customers may be similarly affected by prolonged changes in economic and industry conditions. We perform ongoing credit evaluations of our customers and do not generally require collateral in support of our trade receivables. We maintain reserves for credit losses and, generally, actual losses have been consistent with our expectations, with the exception of losses we sustained relating to obligations of certain Enron entities to KCS.

If we are unsuccessful transporting our oil and natural gas to market at commercially acceptable prices, our profitability will decline.

We deliver oil and natural gas through gathering systems and pipelines that we do not own. Our ability to transport our oil and natural gas to market at commercially acceptable prices or at all depends on, among other factors, the following:

- the availability, proximity and capacity of third-party gathering systems, processing facilities and pipelines;
- changes in supply and demand; and
- general economic conditions.

Our inability to respond appropriately to changes in any of the foregoing factors could negatively affect our profitability.

In addition, the transportation by pipeline of oil and natural gas in interstate commerce is heavily regulated by the FERC, including regulation of the cost, terms and conditions for such transportation service, and in the case of natural gas, the construction and location of pipelines. The transportation by pipeline of oil and natural gas in intrastate commerce is generally subject to varying degrees of state regulation of the cost, terms and conditions of service. While we are not directly subject to these regulations, they affect the cost and availability of transportation of our production to market.

Uninsured judgments or a rise in insurance premiums may adversely impact our results of operations.

Exploration for, and production of, oil and natural gas can be hazardous, involving unforeseen occurrences. Accordingly, in the ordinary course of business, we are subject to various claims and litigation. Although we maintain insurance to cover certain potential claims and losses arising from our operations in accordance with customary industry practices and in amounts that management believes to be prudent, we could become subject to a judgment for which we are not adequately insured and beyond the amounts that we currently have reserved or anticipate reserving. Additionally, the terrorist attacks of September 11, 2001 and the continued hostilities in the Middle East and other sustained military campaigns may adversely impact our ability to obtain insurance or impact the cost of this insurance, either of which may adversely impact our results of operations.

Terrorist attacks and continued hostilities in the Middle East or other sustained military campaigns may adversely impact our financial condition and operations.

The terrorist attacks that took place in the United States on September 11, 2001 were unprecedented events that have created many economic and political uncertainties, some of which may materially adversely impact our business. The continued threat of terrorism and the impact of military and other action, including U.S. military operations in Iraq, will likely lead to continued volatility in prices for crude oil and natural gas and could affect the markets for our operations. In addition, future acts of terrorism could be directed against companies operating in the United States. The United States government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations, and those of our purchasers, to increased risks and, depending on their ultimate magnitude, may adversely impact our financial condition and operations.

Our success depends on key members of senior management, the loss of whom could disrupt our customer relationships and business operations.

We believe our continued success depends in large part on the sustained contributions of our chief executive officer and chairman of the board of directors, James W. Christmas, our president and chief operating officer, William N. Hahne, and our management team and technical personnel. We rely on our executive officers and senior management to identify and pursue new business opportunities and identify key growth opportunities. In addition, the relationships and reputation that members of our management team have established and maintained in the oil and natural gas community contribute to our ability to maintain positive customer relations and to identify new business opportunities. The loss of services of Messrs. Christmas or Hahne or one or more senior management or technical staff could significantly impair our ability to identify and secure new business opportunities and otherwise disrupt operations. We do not maintain key person life insurance on any of our senior management members.

We engage in hedging transactions, which may limit our potential gains and expose us to risk of financial loss.

We periodically purchase or sell derivative instruments covering a portion of our expected production in order to manage our exposure to price risk in marketing our oil and natural gas. These instruments may include futures contracts and options sold on the New York Mercantile Exchange and privately negotiated forwards, swaps and options. These transactions may limit our potential gains if oil and natural gas prices were to rise substantially over the prices established by hedging. These transactions also may expose us to the risk of financial loss in certain circumstances, including the following:

- production is less than the volume hedged;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in hedging arrangements;
- the counterparties to our derivative instruments fail to perform their contract obligations;
- we fail to make timely deliveries; and
- a sudden, unexpected event materially impacts oil or natural gas prices.

Shortage of drilling rigs, equipment, supplies or personnel may delay or restrict our operations.

The oil and natural gas industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or personnel. During these periods, the costs and delivery times of drilling rigs, equipment and supplies are substantially greater. In addition, demand for, and wage rates of, qualified drilling rig crews rise with increases in the number of active rigs in service. Shortages of drilling rigs, equipment, supplies or personnel may increase drilling costs or delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

Our leverage and debt service obligations may adversely affect our cash flow and our financial and operating activities.

As of December 31, 2004, we had $175 million of total debt outstanding. Our level of indebtedness may have important consequences for us, including the following:

- our ability to obtain additional financing for acquisitions, working capital or other expenditures could be impaired or financing may not be available on acceptable terms;

- a substantial portion of our cash flow will be used to make interest and principal payments on our debt, reducing the funds that would otherwise be available for our operations and future business opportunities;

- a substantial decrease in our revenues as a result of lower oil and natural gas prices, decreased production or other factors could make it difficult for us to meet debt service requirements and force us to modify our operations; and

- making us more vulnerable to a downturn in our business or the economy in general.

In addition to our current indebtedness, we may be able to incur substantially more debt. This could exacerbate the risks described above.

Together with our subsidiaries, we may be able to incur substantially more debt in the future. Although our bank credit facility and the indenture governing our senior notes contain restrictions on our incurrence of additional indebtedness, these restrictions are subject to a number of qualifications and exceptions, and under certain circumstances, indebtedness incurred in compliance with these restrictions could be substantial. Also, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness as defined in the relevant agreement. As of December 31, 2004, we had $100 million of borrowing capacity available under our bank credit facility and an unlimited amount of capacity available under our indenture, in each case subject to a number of qualifications. To the extent new debt is added to our current debt levels, the risks described above could substantially increase.

We are dependent on our subsidiaries for our cash flow.

We are a holding company with no material assets other than the equity interests of our subsidiaries. Our subsidiaries conduct substantially all of our operations and directly own substantially all of our assets. Therefore, our operating cash flow and ability to meet our debt obligations will depend on the cash flow provided by our subsidiaries in the form of loans, dividends or other payments to us as a shareholder, equity holder, service provider or lender. The ability of our subsidiaries to make such payments to us will depend on their earnings, tax considerations, legal restrictions and restrictions under their indebtedness.

Our bank credit facility and indenture governing our senior notes impose restrictions on us that may affect our ability to successfully operate our business and our ability to make payments on our indebtedness.

Our bank credit facility and the indenture governing our senior notes include covenants that, among other things, restrict our ability to:

- borrow money;
- create liens;
- sell or transfer any of our material property;
- merge into or consolidate with any third party or sell or dispose of all or substantially all of our assets; and
- make capital expenditures.

We are also required by our bank credit facility to maintain specified interest coverage and current ratios. All of these and other covenants may restrict our ability to expand or to pursue our business strategies. Adverse financial or economic developments may cause us to breach these covenants. The breach of any of these covenants could result in a default under our debt, causing the debt to become due and payable. We may not be able to repay the debt due as a result of an acceleration.

From time to time, we may require consents or waivers from our lenders to permit any necessary actions that are prohibited by our debt and financing arrangements. If in the future our lenders refuse to provide any necessary waivers of the restrictions contained in our debt and financing arrangements, then we could be in default under our debt and financing arrangements, and we could be prohibited from undertaking actions that are necessary to maintain and expand our business.

Anti-takeover provisions in our certificate of incorporation, by-laws and Delaware law could discourage a change of control of our company and could negatively affect our stock price.

Provisions in our certificate of incorporation and by-laws, each as amended to date, and applicable provisions of the Delaware General Corporation Law may make it more difficult and expensive for a third party to acquire control of us even if a change of control would be beneficial to the interests of our stockholders. These provisions could discourage potential takeover attempts and could adversely affect the market price of our common stock. Our certificate of incorporation and by-laws, each as amended to date:

- classify the board of directors into staggered, three-year terms, which may lengthen the time required to gain control of our board of directors;
- limit who may call special meetings;
- prohibit stockholder action by written consent, requiring all actions to be taken at a meeting of the stockholders;
- do not permit cumulative voting in the election of directors, which would otherwise allow holders of less than a majority of stock to elect some directors;
- limit the ability of stockholders to remove directors by providing that they may only be removed for cause; and
- allow our board of directors to determine the powers, preferences or rights and the qualifications, limitations and restrictions of shares of our preferred stock.

In addition, Section 203 of the Delaware General Corporation Law may discourage, delay or prevent a change in control by prohibiting us from engaging in a business combination with an interested stockholder for a period of three years after the person becomes an interested stockholder.

Competition

We operate in the highly competitive exploration and production segment of the oil and gas industry. We compete with major oil and natural gas companies, other independent oil and natural gas concerns and individual producers and operators in the areas of reserve and leasehold acquisitions and the exploration, development, production and marketing of oil and natural gas, as well as contracting for equipment and the hiring of personnel. The principal competitive factors in acquiring, discovering, producing and marketing oil and natural gas reserves are the availability and hiring of qualified personnel, technology and financial resources. We may be at a disadvantage to many of our competitors in one or more of these areas due to our size relative to other companies in the industry.

Marketing and Customers

We market the majority of the natural gas and oil production from properties we operate for both our account and the account of the other working and royalty interest owners in these properties. In some instances, we also market our non-operated natural gas and crude oil production to enhance price realization and cash flow. The production is sold to a variety of purchasers. The terms of sale under the majority of existing contracts are short-term, usually one to three months in duration. The prices received for natural gas and oil sales are tied to monthly or daily indices as quoted in industry publications.

In order to achieve more predictable cash flow and reduce exposure to price volatility of natural gas and crude oil, we utilize fixed price sales and derivative agreements for a portion of our production with unaffiliated third parties. Please read Note 11 to our Consolidated Financial Statements for information regarding our derivative instruments.

In 2004, one customer, Louis Dreyfus Energy Services LP, accounted for 19% of our consolidated revenue. Other than the amortization of deferred revenue associated with the Production Payment, no customer accounted for more than 10% of our consolidated revenues in 2003 or 2002.

Seasonality

Demand for natural gas and oil is seasonal and is principally related to weather conditions and access to pipeline transportation.

Employees

As of December 31, 2004, we employed a total of 133 persons. None of our employees are represented by a labor union. Relations between us and our employees are considered to be satisfactory.

Available Information

Our Internet website is www.kcsenergy.com. The Investor Relations portion of our Internet website is www.kcsenergy.com/html/investor.html and it contains information about us, including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. These reports are available free of charge on the Investor Relations portion of our Internet website on the same day that we electronically file these materials with, or furnish these materials to, the Securities and Exchange Commission.

Item 2. *Properties.*

Reference is made to Item 1. Business, "— Oil and Gas Properties," "— Oil and Natural Gas Reserves," "— Production," "— Acreage," "— Title to Interests," "— Drilling Activities" and "— Other Facilities" included elsewhere in this annual report on Form 10-K.

Item 3. *Legal Proceedings.*

Reference is made to Note 12 to our Consolidated Financial Statements included elsewhere in this annual report on Form 10-K.

Item 4. *Submission of Matters to a Vote of Security Holders.*

No matter was submitted to a vote of our security holders through the solicitation of proxies or otherwise during the fourth quarter of the fiscal year ended December 31, 2004.

PART II

Item 5. *Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Our common stock is traded on the New York Stock Exchange under the symbol "KCS." As of March 1, 2005, there were approximately 917 holders of record of our common stock. This number does not include any beneficial owners for whom shares of common stock may be held in "nominee" or "street" name. The following table sets forth, for each quarterly period during fiscal 2004 and 2003, the high and low sales price per share of our common stock, as reported in the composite transaction reporting system.

	Common Stock Price Range	
	High	Low
Fiscal 2004		
First Quarter	$11.50	$ 8.68
Second Quarter	13.60	10.50
Third Quarter	14.99	11.26
Fourth Quarter	15.09	12.29
Fiscal 2003		
First Quarter	$ 3.06	$ 1.76
Second Quarter	5.70	2.31
Third Quarter	7.64	4.71
Fourth Quarter	10.84	6.77

On March 11, 2005, the last reported sales price of our common stock on the New York Stock Exchange was $16.26 per share.

Dividend Policy

We have not declared or paid any cash dividends on our common stock since 1999. We intend to retain earnings for use in the operation and expansion of our business, and therefore do not anticipate declaring or paying a cash dividend on our common stock in the foreseeable future. In addition, our bank credit facility prohibits the payment of cash dividends on our common stock.

Equity Compensation Plan Information

The following table sets forth information with respect to shares of our common stock that may be issued upon the exercise of options, warrants and rights under all of our existing equity compensation plans as of December 31, 2004.

	Equity Compensation Plan Information		
Plan Category	**Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)**	**Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)**	**Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a))(c)**
Equity compensation plans approved by security holders	—	—	—
Equity compensation plans not approved by security holders	1,479,807(1)	$5.17	2,388,992(2)
Total	1,479,807(1)	$5.17	2,388,992(2)

(1) Represents options granted under our 2001 Employee and Directors Stock Plan. Excludes warrants to purchase 200,000 shares of our common stock whose exercise price is $4.00 per share. The warrants were exercised in full in March 2005 and therefore are no longer outstanding. Please read Note 8 to our Consolidated Financial Statements for more information on the warrants.

(2) Includes 977,606 shares authorized for issuance pursuant to our 2001 Employee and Directors Stock Plan, 754,070 shares authorized for issuance pursuant to our employee stock purchase program and 657,316 shares authorized for issuance in connection with our savings and investment (401(k)) plan.

Information Regarding Equity Compensation Plans That Have Not Been Approved by Stockholders

KCS Energy, Inc. 2001 Employees and Directors Stock Plan, or 2001 Stock Plan. The 2001 Stock Plan was adopted as part of our plan of reorganization, or the Plan, under Chapter 11 of Title 11 of the United States Bankruptcy Code. The Plan was approved by our stockholders and creditors. However, our stockholders did not consider and vote on the 2001 Stock Plan independently of their consideration of the Plan. The 2001 Stock Plan provides that stock options, stock appreciation rights, restricted stock and bonus stock may be granted to our employees. The 2001 Stock Plan provides that each non-employee director will be granted stock options for 1,000 shares of our common stock on an annual basis. The 2001 Stock Plan also provides that in lieu of cash, each non-employee director may be issued shares of our common stock with a fair market value equal to 50% of the non-employee directors' annual retainer. The 2001 Stock Plan provides that the option price of shares issued under the plan shall be equal to the market price on the date of grant. All options expire ten years after the date of grant. The 2001 Stock Plan provides for the issuance of up to 4,362,868 shares of our common stock. As of December 31, 2004, grants of 586,279 restricted shares were outstanding under the 2001 Stock Plan. Please read Note 5 to our Consolidated Financial Statements for a discussion of the terms of the restricted stock.

Other Plans. Shortly after our formation in May 1988, we adopted, among other benefit programs, an employee stock purchase plan and a savings and investment plan. The stockholders of our former parent company did not specifically vote to approve these plans, but they did approve a plan authorizing our spin-off and formation that included provisions stating the intent to adopt benefit plans similar to those of the former parent.

Employee Stock Purchase Plan. Under the employee stock purchase plan, eligible employees and directors may purchase full shares from us at a price per share equal to 90% of the market value determined by the closing price on the date of purchase. The maximum annual purchase amount for our employees is the number of shares costing no more than 10% of the eligible employee's annual base salary. The maximum annual purchase amount for our directors is 6,000 shares. Please read Note 5 to our Consolidated Financial Statements for more information.

Savings and Investment Plan. Under the savings and investment plan, eligible employees may contribute a portion of their compensation, as defined in the plan, to the savings and investment plan, subject to certain Internal Revenue Service limitations. We may provide matching contributions, currently set by the board of directors at 50% of the employee's contribution (up to 6% of the employee's compensation, subject to certain regulatory limitations). The savings and investment plan also contains a profit-sharing component whereby the board of directors may declare annual discretionary profit-sharing contributions. Our matching contributions and discretionary profit-sharing contributions vest over a four-year employment period. Once the four-year employment period has been satisfied, all of our matching contributions and discretionary profit-sharing contributions immediately vest. Please read Note 4 to our Consolidated Financial Statements for more information.

Item 6. *Selected Financial Data.*

The following table sets forth our selected historical financial data for each of the five years in the period ended December 31, 2004. The selected historical financial data set forth below has been derived from our audited consolidated financial statements included elsewhere in this annual report on Form 10-K. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our audited consolidated financial statements and related notes included elsewhere in this annual report on Form 10-K for a discussion of factors that affect the comparability of this information and material uncertainties that may cause this information not to be indicative of our future financial condition or results of operations.

	Year Ended December 31,				
	2004(1)	2003(2)	2002(3)	2001	2000
	(In thousands, except ratios)				
Income Statement Data:					
Oil and natural gas revenue	$197,385	$131,940	$ 74,820	$111,345	$ 190,511
Amortization of deferred revenue	21,370	27,886	45,182	63,089	—
Other, net	(1,466)	5,001	(1,183)	17,557	1,478
Total revenue and other	217,289	164,827	118,819	191,991	191,989
Operating costs and expenses:					
Lease operating expenses	28,600	24,596	22,878	28,337	25,661
Production and other taxes	14,208	10,010	7,957	10,314	8,745
General and administrative expenses	9,123	8,011	8,255	8,885	8,417
Stock compensation	2,621	2,715	782	1,419	—
Bad debt expense	152	339	215	4,074	400
Accretion of asset retirement obligation accretion	1,029	1,116	—	—	—
Depreciation, depletion and amortization	57,309	47,885	49,251	58,314	50,451
Total operating costs and expenses	113,042	94,672	89,338	111,343	93,674
Operating income	104,247	70,155	29,481	80,648	98,315
Interest and other income	317	112	279	1,319	101
Redemption premium on early extinguishment of debt	(3,698)	—	—	—	—
Interest expense	(14,336)	(20,970)	(19,945)	(21,799)	(41,460)
Income before reorganization items and income taxes	86,530	49,297	9,815	60,168	56,956

	Year Ended December 31,				
	2004(1)	2003(2)	2002(3)	2001	2000
	(In thousands, except ratios)				
Reorganization items					
Write-off of deferred debt issuance costs related to senior notes and senior subordinated notes	—	—	—	—	(6,132)
Financial restructuring costs	—	—	—	(3,175)	(10,334)
Interest income	—	—	—	227	1,033
Reorganization items, net	—	—	—	(2,948)	(15,433)
Income before income taxes and cumulative effect of accounting change	86,530	49,297	9,815	57,220	41,523
Federal and state income tax expense (benefit)	(13,905)	(20,229)	13,763	(8,359)	—
Net income (loss) before cumulative effect of accounting change	100,435	69,526	(3,948)	65,579	41,523
Cumulative effect of accounting change, net of tax	—	(934)	(6,166)	—	—
Net income (loss)	100,435	68,592	(10,114)	65,579	41,523
Dividends and accretion of issuance costs on preferred stock	—	(909)	(1,028)	(1,761)	—
Income (loss) available to common stockholders	$100,435	$ 67,683	$(11,142)	$ 63,818	$ 41,523
Earnings (loss) per common share:					
Basic income (loss)	$ 2.06	$ 1.71	$ (0.31)	$ 2.02	$ 1.42
Diluted income (loss)	$ 2.03	$ 1.61	$ (0.31)	$ 1.69	$ 1.42
Other Financial Data:					
Net cash provided by operating activities	134,066	71,022	20,825	183,419	128,007
Capital expenditures	167,176	88,791	47,508	87,192	69,078
Ratio of earnings to fixed charges	6.49	3.20	1.43	3.50	1.97
Balance Sheet Data (at end of period):					
Working capital (deficit)	(28,742)	(20,792)	(16,479)	(3,053)	49,230(4)
Total assets	487,308	342,966	268,133	346,726	347,335
Long-term debt:					
Bank credit facilities	—	17,000	500	—	76,705(5)
7⅛% Senior Notes	175,000	—	—	—	—
11% Senior Notes	—	—	61,274	79,800	150,000
8⅞% Senior Subordinated Notes	—	125,000	125,000	125,000	125,000
Deferred revenue	17,326	38,696	66,582	111,880	—
Preferred stock	—	—	12,859	15,589	—
Stockholders' equity (deficit)	207,049	98,031	(42,716)	(39,460)	(108,320)

(1) Includes a $13.9 million income tax benefit related to the reversal of the remaining portion of our valuation allowance against net deferred income tax assets.

(2) Includes a $20.2 million income tax benefit related to the reversal of a portion of our valuation allowance against net deferred income tax assets and a $0.9 million non-cash charge related to the cumulative effect of an accounting change as a result of the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations."

(3) Includes a $15.9 million non-cash write-down to zero of the book value of net deferred tax assets and a $6.2 million non-cash charge for the cumulative effect of an accounting change related to the amortization method of oil and gas properties.

(4) Excludes debt classified as current liability.

(5) Included in current liabilities.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

The following is a discussion and analysis of our financial condition and results of operations and should be read in conjunction with our consolidated financial statements and related notes included elsewhere in this annual report on Form 10-K.

Forward-Looking Statements

The information discussed in this annual report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included herein concerning, among other things, planned capital expenditures, increases in oil and natural gas production, the number of anticipated wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "will," "expect," "estimate," "project," "plan," "believe," "achievable," "anticipate" and similar terms and phrases. Although we believe that the expectations reflected in any forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including:

- the timing and success of our drilling activities;
- the volatility of prices and supply of, and demand for, oil and natural gas;
- the numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and actual future production rates and associated costs;
- our ability to successfully identify, execute or effectively integrate future acquisitions;
- the usual hazards associated with the oil and gas industry (including fires, natural disasters, well blowouts, adverse weather conditions, pipe failure, spills, explosions and other unforeseen hazards);
- our ability to effectively transport and market our oil and natural gas;
- the results of our hedging transactions;
- the availability of rigs, equipment, supplies and personnel;
- our ability to acquire or discover additional reserves;
- our ability to satisfy future capital requirements;
- changes in regulatory requirements;
- the credit risks associated with our customers;
- economic and competitive conditions;
- our ability to retain key members of senior management and key employees;
- uninsured judgments or a rise in insurance premiums;
- our outstanding indebtedness;

- continued hostilities in the Middle East and other sustained military campaigns and acts of terrorism or sabotage; and
- if underlying assumptions prove incorrect.

These and other risks are described in greater detail in "Business — Risk Factors" included elsewhere in this annual report on Form 10-K. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Overview

The year ended December 31, 2004 was an outstanding year for us. We drilled a record 130 wells during 2004, of which 126 were completed, resulting in a 97% success rate and significantly increased production and reserves. In 2004, gross production increased 15%, to 40 Bcfe, while net production after production payment delivery obligations that do not contribute to cash flow from operating activities increased 25% compared to 2003. Natural gas and oil reserves increased 22% to 328 Bcfe as of December 31, 2004 compared to 268 Bcfe as of December 31, 2003. In total, we added 94.5 Bcfe of proved reserves during 2004, of which 97% was through the drill bit. Total oil and gas capital expenditures were $166.7 million.

In 2004, we continued to execute our strategies of focusing on low-risk development and exploitation drilling in our core operating areas and to commit approximately 15% of our capital expenditure budget to moderate-risk, higher-potential exploration prospects primarily in the onshore Gulf Coast region. In 2005, we plan to commit approximately 15% to 20% of our capital expenditure budget to such exploration projects. We continue to focus primarily on natural gas prospects. We have continued our disciplined hedging program designed to protect against price declines while participating to a large extent in future price increases. In this way, we endeavor to ensure that we generate a sufficient level of cash flow to carry out a capital expenditure program sufficient to at least replace our expected production and still benefit if prices rise.

We further strengthened our financial condition in 2004 and provided additional financial flexibility by completing a $175 million senior notes offering. The new senior notes bear interest at an annual rate of 7⅛% and mature in 2012. The proceeds of this issuance were used to redeem our $125 million 8⅞% senior subordinated notes due 2006, including an early redemption premium, and to repay the $22 million outstanding under our bank credit facility. As of December 31, 2004, we had $6.6 million of cash on hand and $100 million of unused committed borrowing capacity under our bank credit facility. We plan to maintain a conservative capital structure. Please read Note 6 to our Consolidated Financial Statements for more information regarding our senior notes and our bank credit facility.

In the Mid-Continent region, we concentrate our drilling programs primarily in north Louisiana, east Texas, Oklahoma (Anadarko and Arkoma basins) and west Texas. Our Mid-Continent region operations provide us with a solid base for production and reserve growth. We plan to continue to exploit areas within the various basins that require low-risk exploitation wells for additional reservoir drainage. Our exploitation wells are generally step-out and extension type wells with moderate reserve potential. During 2004, we drilled 101 wells in this region with a success rate of 97%. In 2005, we plan to drill 90 to 115 wells in this region, approximately half of which are planned in the Elm Grove Field which is our largest field. We will also pursue drilling programs in the Sawyer Canyon, Joaquin, Terryville and Talihina fields and have budgeted $20 million to commence development of the properties being acquired in April 2005.

In the Gulf Coast region, we concentrate our drilling programs primarily in south Texas. We also have working interests in several minor non-operated offshore and Mississippi salt basin properties. We conduct development programs and pursue moderate-risk, higher potential exploration drilling programs in this region. Our Gulf Coast operations have numerous exploration prospects that are expected to provide us additional growth. During 2004, we drilled 13 exploratory and 16 development wells in this region with a success rate of 97%. We anticipate drilling 40 to 50 wells in this region in 2005, approximately three-fourths of which will be exploratory. In 2004, exploration success was achieved in the La Reforma and Coquat fields. In the third quarter of 2004, we acquired a 42,300 acre lease on the O'Connor Ranch and license to approximately 100 square miles of 3D seismic data in Goliad County, Texas. The 2005 drilling program will be concentrated in O'Connor Ranch, La Reforma, Coquat and Austin Deep fields and the West Mission Valley area.

We believe that the steps taken over the last several years position us to continue growing our reserves and production through a balanced investment program including low-risk exploitation and development activities in the Mid-Continent and Gulf Coast regions and moderate-risk, higher potential exploration drilling programs primarily in the onshore Gulf Coast region.

Major Influences on Results of Operations

Oil and natural gas prices. Oil and natural gas prices have been, and are expected to continue to be, volatile. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors beyond our control, including, among others, worldwide political conditions (especially in the Middle East and other oil-producing regions), the domestic and foreign supply of oil and natural gas, the level of consumer demand, weather conditions, domestic and foreign governmental regulations and taxes, the price and availability of alternative fuels and overall domestic and global economic conditions.

The average price we receive for our natural gas production is generally 10 to 15 cents below NYMEX prices at the Henry Hub. The primary factors for this differential are the geographic locations of our producing properties and the Btu content of our natural gas. The average Btu content of our natural gas is in excess of 1,000 Btu per cubic foot. The price we receive for our oil production is generally $1.60 to $1.75 per barrel below the Koch West Texas Intermediate posted prices for sweet crude in Texas/New Mexico.

We use commodity derivative contracts on a limited basis to manage our exposure to oil and natural gas price volatility. Our strategy is to maintain a disciplined approach by layering in a series of derivative contracts at different price levels depending on market conditions and other factors. We typically target hedging 30% to 50% of our near-term production. We do not enter into derivative or other financial instruments for trading or speculative purposes. Excluding the effect of impact of the terminated derivative instruments discussed below, hedging activities decreased realized prices by $0.10 and $0.02 in 2004 and 2003, respectively and increased realized prices by $0.05 in 2002.

Certain terminated derivative instruments also affect our reported realized prices. In February 2001, we terminated $2.055 per MMBtu swaps on 10.1 million MMBtu through 2005 that we inherited when we acquired Medallion California Properties Company and related entities. This resulted in a $28 million hedge loss that is being amortized as a non-cash reduction of revenue over the original term of the derivative instruments. The effect of this amortization of the cost of these terminated swaps was to reduce realized prices by $0.11, $0.16 and $0.18 per Mcfe in 2004, 2003 and 2002, respectively.

Our reported realized prices for oil and natural gas are also affected by the Production Payment we sold in February 2001 at a weighted average discounted price realized of $4.05 per Mcfe which has the effect of lowering our reported realized price in periods when cash prices exceed $4.05 per Mcfe and raising our reported realized prices when cash prices are lower than $4.05 per Mcfe. The effect of the Production Payment was to reduce realized prices by $0.27 per Mcfe and $0.29 per Mcfe in 2004 and 2003, respectively, and to increase realized prices by $0.20 per Mcfe in 2002.

Production. The primary factors affecting our production levels are capital availability, the success of our drilling program and, in 2002, the sales of certain non-core properties and the winding down and expiration of our purchased VPP program.

In 2002, our main objective was to position ourselves to meet our senior note obligations that were due in January 2003. In order to do so, we curtailed our capital spending program and sold certain non-core producing properties. As a result of the property sales and curtailed drilling, our production declined significantly compared to 2001. In 2003 and 2004, we were able to direct our cash flow to our drilling operations and significantly grow production levels and natural gas and oil reserves.

In 2002, 2.5 Bcfe, or 7%, of our production was derived from our purchased VPP program. We have not made any VPP investments since 1999. Final deliveries under our existing VPPs were received in November 2002. Although specific terms of our VPPs varied, we were generally entitled to receive delivery of the scheduled oil and natural gas volumes at agreed delivery points, free of drilling and lease operating expenses and free of state production taxes. During the life of the program, we invested $213.6 million to acquire reserves of 120.3 Bcfe of natural gas and oil and realized approximately $293.9 million from the sale of oil and natural gas acquired as well as an additional 10.6 Bcfe under a VPP that was converted to a working interest.

Our reported production includes volumes dedicated to the Production Payment discussed below. However, we view the net production after our delivery obligations associated with the Production Payment as more important because it is net production that generates cash flow. For example, while total production increased 15%, from 34.7 Bcfe in 2003, to 40.0 Bcfe in 2004, our net production actually increased 25%, from 27.9 Bcfe in 2003, to 34.8 Bcfe in 2004 as delivery obligations associated with the Production Payment declined from 6.8 Bcfe in 2003 to 5.2 Bcfe in 2004. This 1.6 Bcfe less production committed to the Production Payment obligations in 2004 resulted in incremental cash flow of approximately $9.4 million.

Sale of Production Payment. In February 2001, we sold a Production Payment in connection with our emergence from Chapter 11. The net proceeds from this sale of approximately $175 million was recorded as deferred revenue and is amortized over the five-year period that scheduled deliveries of production are made. Deliveries under this Production Payment are recorded as non-cash oil and gas revenue with a corresponding reduction of deferred revenue at the weighted average discounted price realized of approximately $4.05 per Mcfe. We also reflect the production volumes and depletion expense as deliveries are made. However, the associated oil and natural gas reserves are excluded from our oil and natural gas reserve data. Amortization of deferred revenue comprised 10%, 17% and 38% of our oil and gas revenue during 2004, 2003 and 2002, respectively. As of December 31, 2004, 4.1 Bcfe remained to be delivered under the Production Payment of which 3.9 Bcfe will be delivered in 2005 and 0.2 Bcfe in 2006.

Operating Costs. We monitor our business to control costs from both a gross dollar standpoint and from a per unit of production perspective. We are able to control our lease operating expenses because we are focused in certain core areas which allows us to operate efficiently. Lease operating expenses were $28.6 million in 2004, $24.6 million in 2003 and $22.9 million in 2002. These costs reflect the levels of production and workover activities and, in 2004, increased service costs experienced by the oil and gas industry. In order to measure our operating performance, we monitor lease operating expenses on a per unit of production basis. Lease operating expenses (excluding production from purchased VPPs) per Mcfe were $0.72 in 2004, $0.71 in 2003 and $0.65 in 2002.

General and administrative expenses are monitored closely with the objective of operating an efficient organization with an appropriate cost structure. In 2002, we reduced our staff in response to limited capital availability and curtailed drilling activity. In 2003 and 2004, we added staff modestly in response to our resumed growth. General and administrative expenses were $9.1 million, or $0.23 per Mcfe, in 2004, $8.0 million, or $0.23 per Mcfe, in 2003 and $8.3 million, or $0.22 per Mcfe, in 2002.

Factors Affecting Comparability

Sale of Emission Credits. We sold emission credits totaling $4.9 million in 2003 which are reflected in other, net in our statements of consolidated operations. We did not sell any emission credits in 2002 and only a minor amount in 2004. We currently do not anticipate any significant emission credit sales in 2005.

Stock Compensation. Stock compensation was $2.6 million, $2.7 million and $0.8 million in 2004, 2003 and 2002, respectively. These non-cash expenses reflect the amortization of restricted stock grants and expenses associated with certain stock options granted in 2001 that are subject to variable accounting. The stock option expenses can fluctuate significantly as the expense recognized during a reporting period is directly related to the movement in the market price of our common stock during that period.

Redemption Premium on Early Extinguishment of Debt. On May 1, 2004, we redeemed our $125 million 8⅞% senior subordinated notes due 2006. Pursuant to the indenture, we paid an early redemption premium of $3.7 million, which was charged against earnings in the second quarter of 2004.

Income Taxes. During the second quarter of 2002, uncertainty resulting from relatively low commodity prices and the January 2003 maturity date for our senior notes led management to increase the valuation allowance against net deferred income tax assets by $15.9 million. This increase in the valuation allowance reduced the carrying value of net deferred assets to zero and was reflected as income tax expense on our statements of consolidated operations. Since that time, we have generated significant levels of taxable income due to drilling success and strong natural gas and oil prices. We believe that the future outlook for continued generation of taxable income is positive based on existing available information, including prices quoted on the New York Mercantile Exchange and our production levels. During 2003, we reversed approximately $37.6 million of the valuation allowance and in 2004 reversed the remaining $44.2 million of the valuation allowance related to expected taxes on future years' taxable income. These amounts are reflected as an income tax benefit in our statements of consolidated operations. In 2005, while we continue to utilize our net operating loss carryforwards and pay alternative minimum tax of approximately 1% to 2% of pre-tax income, we anticipate that we will record book income tax expense close to the statutory corporate income tax rate of 35%.

Accounting Changes. Our 2002 results included a $6.2 million charge against earnings related to our change to the unit-of-production method of accounting for depreciation, depletion and amortization. This charge is reflected as a cumulative effect of accounting change, net of tax. In 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," and recorded a $0.9 million charge against earnings as a cumulative effect of an accounting change, net of tax. There were no accounting changes that affected us in 2004.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States, or GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect our financial condition and results of operations. Our significant accounting policies are described in Note 1 to our Consolidated Financial Statements contained elsewhere in this annual report on Form 10-K. Certain of these accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We discussed the development, selection, and disclosure of each of these critical accounting estimates with the audit committee of our board of directors. The following discussion details the more significant accounting policies, estimates and judgments.

Full Cost Method of Accounting for Oil and Gas Operations

The accounting for our business is subject to accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and gas business activities: (i) the successful efforts method; and (ii) the full cost method. We have elected to use the full cost method to account for our investment in oil and gas properties. Under this method, we capitalize all acquisition, exploration and development costs into one country-wide cost center. These costs include lease acquisitions, geological and geophysical services, drilling, completion, equipment, certain salaries and other internal costs directly attributable to these activities. These costs are then amortized over the remaining life of the aggregate oil and natural gas reserves using the "unit-of-production" method of calculating depletion expense discussed below under "— Amortization of Oil and Gas Properties." The full cost method embraces the concept that dry holes and other expenditures that fail to add reserves are intrinsic to the oil and gas exploration business and are therefore capitalized. Although some of these costs will ultimately result in no additional reserves, they are part of a program from which we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. As a result, we believe the full cost method of accounting is appropriate and accurately reflects the economics of our programs for the acquisition, exploration and development of oil and natural gas reserves. Under the successful efforts method, costs of exploratory dry holes and geological and geophysical exploration costs that would be capitalized under the full cost method would be charged against earnings during the periods in which they occur. Accordingly, our financial position and results of operations may have been significantly different had we used the successful efforts method of accounting for our oil and gas investments.

Oil and Natural Gas Reserve Estimates

Estimates of our proved oil and natural gas reserves are based on the quantities of oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The accuracy of any oil and natural gas reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also may change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

Despite the inherent imprecision in these engineering estimates, estimates of our oil and natural gas reserves are used throughout our financial statements. For example, as we use the unit-of-production method of calculating depletion expense, the amortization rate of our capitalized oil and gas properties incorporates the estimated units-of-production attributable to the estimates of proved reserves. Our oil and gas properties are also subject to a "ceiling" limitation based in large part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

The estimates of our proved oil and natural gas reserves have been audited or prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers.

Amortization of Oil and Gas Properties

Effective January 1, 2002, we began amortizing the capitalized costs related to our oil and gas properties under the unit-of-production, or UOP, method using proved oil and natural gas reserves. Under the UOP method, the depreciation, depletion and amortization rate is computed based on the ratio of production to total reserves. This rate is applied to the amortizable base of our oil and gas properties (the net book value of oil and gas properties less the costs of unevaluated oil and gas properties plus estimated future costs to develop the oil and gas properties with proved reserves). The calculation of depreciation, depletion and amortization requires the use of significant estimates pertaining to oil and natural gas reserves and future development costs.

Bad Debt Expense

We routinely review all material trade and other receivables to determine the timing and probability of collection. Many of our receivables are from joint interest owners on properties we operate. Therefore, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We market the majority of our production and these receivables are generally collected within a month. The receivables for the remaining production are typically collected within two months. We accrue a reserve for a receivable when, based on the judgment of management, it is doubtful that the receivable will be collected in full and the amount of any reserve required can be reasonably estimated.

Revenue Recognition

Oil and natural gas revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collection of the revenue is probable. We follow the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on actual production volume sold. The volume of natural gas sold may differ from the volume to which we are entitled based on our WI. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under-produced owner(s) to recoup its entitled share through future production. Natural gas imbalances can arise on properties for which two or more owners have the right to take production "in-kind." In a typical gas balancing arrangement, each owner is entitled to an agreed-upon percentage of the property's total production. However, at any given time, the amount of natural gas sold by each owner may differ from its allowable percentage. Two principal accounting practices have evolved to account for natural gas imbalances. These methods differ as to whether revenue is recognized based on the actual sale of natural gas (sales method) or an owner's entitled share of the current period's production (entitlement method). We have elected to use the sales method. If we used the entitlement method, our reported revenues may have been materially different.

Income Taxes

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. In making this assessment, we perform an extensive analysis of our operations to determine the sources of future taxable income. The analysis consists of a detailed review of all available data, including our budget for the ensuing year, forecasts based on current as well as historical prices, and the independent petroleum engineers' reserve report. The determination to establish and adjust a valuation allowance requires significant judgment as the estimates used in preparing budgets, forecasts and reserve reports are inherently imprecise and subject to substantial revision as a result of changes in the outlook for prices, production volumes and costs, among other factors. It is difficult to predict with precision the timing and amount of taxable income we will generate in the future. Our current net operating loss carryforwards aggregating approximately $162 million have remaining lives ranging from 14 to 18 years. However, we examine a much shorter time horizon, usually two to three years, when projecting estimates of future taxable income and making the determination as to whether the valuation allowance should be adjusted.

Asset Retirement Obligations

We have significant obligations to remove equipment and restore land at the end of oil and natural gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating future asset removal costs is difficult and requires management to make estimates and judgments as most of the removal obligations are many years in the future and because contracts and regulations often contain vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are political, environmental, safety and public relations considerations.

SFAS No. 143 "Accounting for Asset Retirement Obligations" requires us to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the periods in which it is incurred. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset. The liability is accreted to the fair value at the time of settlement over the useful life of the asset, and the capitalized cost is depreciated over the useful life of the related asset.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and gas property balance. In addition, increases in the discounted asset retirement obligation resulting from the passage of time will be reflected as accretion expense in the consolidated statement of operations.

Derivatives

We use commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We account for our commodity derivative contracts in accordance with Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," or SFAS No. 133. Realized gains and losses from our cash flow hedges, including terminated contracts, are generally recognized in oil and natural gas production revenue when the hedged volumes are produced and sold. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Results of Operations

Income before income taxes and cumulative effect of accounting change for 2004 increased 76% to $86.5 million compared to $49.3 million in 2003. This increase was primarily attributable to a 15% increase in natural gas and oil production (25% increase in net production contributing to cash flow from operating activities) and a 19% increase in natural gas and oil prices, partially offset by lower non-oil and gas revenue, higher operating expenses and a $3.7 million redemption premium associated with the early redemption of our 8⅞% senior subordinated notes due in 2006. Income tax benefit for 2004 was $13.9 million compared to $20.2 million in 2003 due to changes in our valuation allowance against our net deferred tax asset. Please read Note 10 to our Consolidated Financial Statements. In 2003, we recorded a cumulative effect of accounting change of $0.9 million, or a $0.02 loss per basic and diluted share, as a result of the adoption of SFAS No. 143. Income available to common stockholders in 2004 was $100.4 million, or $2.06 per basic share and $2.03 per diluted share, compared to $67.7 million, or $1.71 per basic and $1.61 per diluted share, in 2003.

Income before income taxes and cumulative effect of accounting change for 2003 was $49.3 million compared to $9.8 million in 2002. This increase was primarily attributable to higher natural gas and oil prices and the sale of emission reduction credits, partially offset by decreased oil and natural gas production due to the expiration of our VPP program and the effect of the sale of certain non-core oil and gas properties in 2002. Income tax benefit for 2003 was $20.2 million compared to an income tax expense of $13.8 million in 2002 due to changes in our valuation allowance against our net deferred tax asset. Please read Note 10 to our Consolidated Financial Statements. The cumulative effect of accounting change was $0.9 million, or a $0.02 loss per basic and diluted share, in 2003 resulting from the adoption of SFAS No. 143. In 2002, the cumulative effect of accounting change was $6.2 million, or a $0.17 loss per basic and diluted share, which reflected the change from the future gross revenue method of accounting for amortization of capitalized costs related to oil and gas properties to the UOP method. Income available to common stockholders in 2003 was $67.7 million, or $1.71 per basic share and $1.61 per diluted share, compared to a loss of $11.1 million, or $0.31 per basic and diluted share, in 2002.

	Year Ended December 31,		
	2004	2003	2002
Production: (a)			
Natural gas (MMcf)	33,905	28,166	29,672
Oil (Mbbl)	795	838	1,003
Natural gas liquids (Mbbl)	216	258	288
Total (MMcfe)	39,971	34,741	37,417
Summary (MMcfe)			
Working interest (b)	39,971	34,741	34,959
Purchased VPP (c)	—	—	2,458
Total	39,971	34,741	37,417
Dedicated to Production Payment	(5,170)	(6,807)	(11,196)
Net Production	34,801	27,934	26,221
Revenue ($000's):			
Natural gas	$190,360	$134,833	$ 96,531
Oil	24,283	21,231	20,578
Natural gas liquids	4,112	3,762	2,893
Total	$218,755	$159,826	$120,002

	Year Ended December 31,		
	2004	2003	2002
Average Price:			
Natural gas (per Mcf)	$ 5.61	$ 4.79	$ 3.25
Oil (per bbl)	30.53	25.34	20.52
Natural gas liquids (per bbl)	19.07	14.58	10.05
Total (per Mcfe) (d)	$ 5.47	$ 4.60	$ 3.21
Production cost ($000's)			
Lease operating expense	$ 28,600	$ 24,596	$ 22,878
Production and other taxes	14,208	10,010	7,957
Total	$ 42,808	$ 34,606	$ 30,835
Average production cost (per Mcfe) (c):			
Lease operating expense	$ 0.72	$ 0.71	$ 0.65
Production and other taxes	0.35	0.29	0.23
Total	$ 1.07	$ 1.00	$ 0.88

(a) Includes delivery obligations dedicated to the Production Payment. Production includes 5,170 MMcfe in 2004, 6,807 MMcfe in 2003 and 11,196 MMcfe in 2002 dedicated to the Production Payment. Please read Note 1 to our Consolidated Financial Statements for more information on the Production Payment.

(b) We sold properties in 2002 to reduce debt.

(c) We discontinued making new investments in VPPs in 1999 and final deliveries from our VPP program were received in November 2002. The average production cost per Mcfe in 2002 excludes the production received under our purchased VPP program because that production was free from these expenses.

(d) The average realized prices reported above include the non-cash effects of volumes delivered under the Production Payment as well as the unwinding of various derivative contracts terminated in 2001. These items do not generate cash to fund our operations. Excluding these items, the average realized price per Mcfe was $5.85, $5.05 and $3.19 in 2004, 2003 and 2002, respectively. For further information, please read, "— Major Influences on Results of Operations."

Revenue

Natural Gas Revenue. In 2004, natural gas revenue increased $55.6 million, to $190.4 million, compared to $134.8 million in 2003 as a result of a 20% increase in production and a 17% increase in realized natural gas prices. The production increase was primarily due to our successful drilling program.

In 2003, natural gas revenue increased $38.3 million, to $134.8 million, compared to $96.5 million in 2002 as a result of a 47% increase in realized natural gas prices and a 5% decrease in production. The production decrease was primarily due to the expiration of our VPP program, as new production from the successful drilling program essentially offset the impact of 2002 property sales and the natural decline of producing wells.

Oil and Liquids Revenue. In 2004, oil and liquids revenue increased $3.4 million to $28.4 million due to a 23% increase in average realized prices, partially offset by an 8% decrease in production. In 2003, oil and liquids revenue increased $1.5 million to $25.0 million due to a 25% increase in average realized prices offset by a 15% decrease in production. The decrease in oil and natural gas liquids production reflected the natural decline associated with our oil and natural gas liquids properties as our drilling program over the last several years has been focused almost entirely on natural gas prospects.

Other, net. In 2004, other, net was a loss of $1.5 million, of which $1.1 million was due to losses associated with certain derivatives that did not qualify for hedge accounting treatment pursuant to SFAS No. 133. This compares to other, net revenue of $5.0 million in 2003 which was primarily attributed to the sale of emission reduction credits. Other, net was $5.0 million in 2003 compared to a net cost of $1.2 million in 2002. The increase was primarily attributed to the sale of emission reduction credits. We do not anticipate that there will be any significant sales of emission credits in 2005.

Lease Operating Expenses

For the year ended December 31, 2004, lease operating expenses, or LOE, increased $4.0 million, to $28.6 million, compared to $24.6 million in 2003 due to generally higher service costs experienced industry-wide and the increase in the number of producing wells as a result of our expanded drilling program. On a per unit of production basis, LOE was $0.72 per Mcfe of WI production in 2004 compared to $0.71 per Mcfe in 2003.

For the year ended December 31, 2003, LOE increased $1.7 million, to $24.6 million, compared to $22.9 million in 2002. The increase was primarily attributed to a higher level of workover activity on oil and gas wells in 2003. On a per unit of production basis, LOE was $0.71 per Mcfe of WI production in 2003 compared to $0.65 per Mcfe in 2002.

Production and Other Taxes

Production and other taxes increased $4.2 million to $14.2 million in 2004, compared to $10.0 million in 2003. The increase was primarily attributable to increased production (severance) taxes due to higher oil and gas revenue and higher ad valorem taxes due to the higher value of our oil and gas properties.

Production and other taxes increased $2.0 million to $10.0 million in 2003, compared to $8.0 million in 2002. The increase was primarily attributable to higher oil and natural gas revenue and higher production tax rates in Louisiana where we significantly increased our production in the Elm Grove Field.

General and Administrative Expenses

General and administrative expenses, or G&A, increased $1.1 million to $9.1 million in 2004, compared to $8.0 million in 2003 primarily due to increased costs to comply with corporate governance initiatives mandated by the Sarbanes-Oxley Act of 2002 and the New York Stock Exchange and higher insurance costs. On a per unit of the production basis, G&A was $0.23 per Mcfe in 2004 and 2003.

G&A decreased $0.3 million to $8.0 million in 2003, compared to $8.3 million in 2002. On a per unit of production cost basis, G&A was $0.23 per Mcfe for 2003 and $0.24 for 2002. The overall decrease resulted from lower labor costs associated with a reduced work force, partially offset by a higher incentive compensation expense resulting from improved operating results.

Stock Compensation

Stock compensation reflects the non-cash expense associated with stock options issued in 2001 that are subject to variable accounting in accordance with FASB Interpretation No. 44, "Accounting for Certain Transactions Involving Stock Compensation," or FIN 44, and the non-cash expense associated with the amortization of restricted stock grants. Under variable accounting for stock options, the amount of expense recognized during a reporting period is directly related to the movement in the market price of our common stock during that period. For 2004, stock compensation was $2.6 million compared to $2.7 million in 2003.

Stock compensation was $2.7 million in 2003 compared to $0.8 million in 2002 primarily due to the significant increase in the market price of our common stock during 2003.

Accretion of Asset Retirement Obligation

Effective January 1, 2003, we adopted SFAS No. 143. Accretion of our asset retirement obligation was $1.0 million in 2004 and $1.1 million in 2003.

Depreciation, Depletion and Amortization

We amortize our oil and gas properties using the UOP method based on proved reserves. For the year ended December 31, 2004, depreciation, depletion and amortization expense was $57.3 million ($1.43 per Mcfe) compared to $47.9 million ($1.38 per Mcfe) for the year ended December 31, 2003. This $9.4 million increase reflects the higher production associated with our successful drilling program and the increased cost of drilling wells.

For the year ended December 31, 2003, depreciation, depletion and amortization expense was $47.9 million ($1.38 per Mcfe) compared to $49.3 million ($1.41 per Mcfe) for the year ended December 31, 2002. This $1.4 million decrease was primarily attributable to reduced production as a result of the expiration of our VPP program and the sale of certain non-core oil and gas properties in 2002.

Interest and Other Income

Interest and other income was $0.3 million in 2004 compared to $0.1 million in 2003 and $0.3 million in 2002. These amounts primarily represent interest income earned on accumulated cash and cash equivalents.

Redemption Premium on Early Extinguishment of Debt

On May 1, 2004, we redeemed our $125 million 8⅞% senior subordinated notes due 2006. Pursuant to the indenture, we paid an early redemption premium of $3.7 million, which was charged against earnings in the second quarter of 2004.

Interest Expense

Interest expense was $14.3 million in 2004 compared to $21.0 million in 2003. This significant decrease in interest expense in 2004 reflects reduced amounts of average outstanding debt and substantially lower borrowing costs.

Interest expense was $21.0 million in 2003 compared to $19.9 million in 2002. The higher interest expense in 2003 reflects the $2.8 million write-off of deferred financing costs and a $0.5 million early termination fee paid to a previous lender as a result of amending and restating our bank credit facility in November 2003 to increase availability and reduce future interest costs. Interest expense excluding amortization of deferred financing costs was $1.2 million lower in 2003 compared to 2002 primarily due to lower average outstanding debt in 2003.

Income Taxes

Income tax benefits were $13.9 million in 2004 compared to $20.2 million in 2003 and income tax expense of $13.8 million in 2002. These amounts reflect changes in our valuation allowance against net deferred income tax assets. In making our assessment of the valuation allowance, we perform an extensive analysis of our operations to determine the sources of future taxable income. The analysis consists of a detailed review of all available data, including our budget for the ensuing year, forecasts based on current as well as historical prices, and our oil and gas reserve report.

During the second quarter of 2002, uncertainty resulting from relatively low commodity prices and the January 2003 maturity date for our senior notes led management to increase the valuation allowance by $15.9 million. This increase in the valuation allowance reduced the carrying value of net deferred assets to zero. Since that time, we have generated significant levels of taxable income due to drilling success and strong natural gas and oil prices. We believe that the future outlook for continued generation of taxable income is positive based on existing available information, including current prices quoted on the New York Mercantile Exchange. Therefore, during 2003, we reversed approximately $37.6 million of the valuation allowance and in 2004 reversed the remaining $44.2 million of the valuation allowance related to expected taxes on future years' taxable income.

Liquidity and Capital Resources

Our primary cash requirements are for the exploration, development and acquisition of oil and gas properties, operating expenses and debt service. We expect to fund our drilling activities primarily with internally generated cash flow and to have sufficient capital resources available to allow us the flexibility to be opportunistic with our drilling program and to fund larger acquisitions and working capital requirements. We believe this approach allows us to maintain an appropriate capital structure that allows us to increase our oil and gas reserves and to reduce debt per Mcfe. In 2004, we accelerated our drilling program given the relatively high oil and gas price environment and drilled 130 wells with a 97% success rate. As a result, we were able to significantly increase oil and gas production, reserves and cash flow. Cash used in investing activities, primarily for our drilling program, was $155.1 million. Net cash provided by operating activities was $134.1 million. Proceeds from our senior notes offering discussed below funded the remainder of our drilling program.

In April 2004, we completed a private placement of $175 million of 7⅞% senior notes due 2012. The net proceeds of this issuance were used to redeem our $125 million 8⅞% senior subordinated notes due 2006, to repay the $22 million outstanding under our bank credit facility and for general corporate purposes, including our drilling program. On May 1, 2004, we redeemed our $125 million 8⅞% senior subordinated notes due 2006. Pursuant to the indenture, we paid an early redemption premium of $3.7 million. Please read Note 6 to our Consolidated Financial Statements for more information regarding our senior notes, including a discussion of restrictive covenants.

We also have a bank credit facility that currently provides up to $100 million of revolving credit capacity and matures on November 20, 2006. There were no outstanding borrowings under this facility as of December 31, 2004. Borrowing capacity under the bank credit facility is subject to a borrowing base (currently $100 million) and is reviewed at least semi-annually and may be adjusted based on the lenders' valuation of our oil and natural gas reserves and other factors. Please read Note 6 to our Consolidated Financial Statements for more information regarding our bank credit facility, including a discussion of restrictive covenants.

In February 2005, we entered into a purchase and sale agreement to acquire certain oil and gas properties and related assets for approximately $94.7 million, subject to certain purchase price adjustments. The transaction is subject to due diligence and other conditions prior to closing, which is scheduled to occur in mid-April 2005. We expect to initially finance the acquisition with cash on hand and borrowings under our bank credit facility. Please read Note 15 to our Consolidated Financial Statements for more information regarding this acquisition.

In 2005, we have budgeted approximately $190 million for capital investments in natural gas and oil properties, excluding the cost of acquisitions, and anticipate drilling approximately 150 wells. We expect to fund our 2005 exploration and development activities primarily through internally generated cash flows. The amount and allocation of our capital investment program is subject to change based on operational developments, commodity prices, service costs, acquisitions and numerous other factors. Generally, we do not budget for acquisitions.

Our net working capital position as of December 31, 2004 was a deficit of $28.7 million. On that date, we had $100.0 million of unused availability under our bank credit facility and $6.6 million of cash on hand. Working capital deficits are not unusual in our industry. We, like many other oil and gas companies, typically maintain relatively low cash reserves and use any excess cash to fund our capital expenditure program or pay down borrowings under our bank credit facility. The December 31, 2004 working capital deficit was higher than usual due mainly to the high level of accrued drilling costs ($21.9 million) as a result of our active drilling program.

We believe that cash on hand, net cash generated from operations and unused committed borrowing capacity under our bank credit facility will be adequate to fund our capital expenditure program and satisfy our liquidity needs. In the future, we may also utilize various financing sources available to us, including the issuance of debt or equity securities under our shelf registration statement or through private placements. Our ability to complete future debt and equity offerings and the timing of these offerings will depend upon various factors including prevailing market conditions, interest rates and our financial condition.

Cash Flow from Operating Activities

Net cash provided by operating activities for 2004 was $134.1 million compared to $71.0 million in 2003. The 89% improvement in our cash flow in 2004 was primarily due to higher production, higher realized oil and natural gas prices and decreased delivery obligations under the Production Program. The net increase in trade accounts receivable also reflects the higher natural gas and oil price environment in 2004 and the timing of cash receipts for sales of our increased production. The net change in accounts payable and accrued liabilities is primarily attributable to our expanded drilling program.

Net cash provided by operating activities for 2003 was $71.0 million compared to $20.8 million in 2002. The improvement in our cash flow in 2003 was primarily due to higher realized oil and natural gas prices and substantially less production dedicated to repayment of the Production Payment. The net increase in trade accounts receivable reflects the higher natural gas and oil price environment in 2003 and the timing of cash receipts. The net change in accounts payable and accrued liabilities is primarily attributable to increased drilling well pre-payments received from non-operating working interest owners and higher incentive compensation accruals.

Investing Activities

Net cash used in investing activities in 2004 was $155.1 million, virtually all of which was for oil and gas properties, compared to net cash used in investing activities of $79.0 million in 2003 and $18.1 million in 2002. In 2003, we invested $78.1 million in oil and gas properties, and in 2002, we invested $48.6 million in oil and gas properties and realized $30.5 million from the sale of non-core properties.

Capital expenditures for the year ended December 31, 2004 were $167.2 million, including $132.1 million used for development activities, $34.1 million used for lease acquisitions, seismic surveys and exploratory drilling, $0.5 million in capitalized asset retirement obligation and $0.5 million used for other assets. These amounts include costs that were incurred and accrued as of December 31, 2004 but are not reflected in the net cash used in investing activities above until payment is made in 2005.

Capital expenditures for the year ended December 31, 2003 were $88.8 million, including $78.2 million used for development activities, $9.9 million used for lease acquisitions, seismic surveys and exploratory drilling and $0.7 million used for other assets. These amounts include costs that were incurred and accrued as of December 31, 2003 but not reflected in the net cash used in investing activities above until payment was made in 2004.

Capital expenditures for the year ended December 31, 2002 were $47.5 million, including $30.3 million used for development activities, $4.8 million used for the acquisition of proved reserves and $12.4 million used for lease acquisitions, seismic surveys and exploratory drilling.

Financing Activities

Net cash provided by financing activities in 2004 was $25.4 million due to the refinancing of our debt as discussed above and in Note 6 to our Consolidated Financial Statements. Net cash provided by financing activities was $3.2 million in 2003 and net cash used in financing activities was $18.8 million in 2002. In 2003, net proceeds from our common stock offering were $52.0 million, proceeds from borrowings under the bank credit facility were $69.3 million, repayments of debt were $114.1 million and net payments of deferred financing costs and other were $4.0 million. In 2002, proceeds from borrowings were $0.5 million, repayments of debt were $18.5 million and payments for deferred financing costs and other were $0.7 million.

Shelf Registration Statement/Common Stock Offering

In September 2003, we, along with two of our operating subsidiaries, KCS Resources, Inc. and Medallion California Properties Company, filed a $200.0 million universal shelf registration statement with the Securities and Exchange Commission. The shelf registration statement covers the issuance of an unspecified amount of senior unsecured debt securities, senior subordinated debt securities, common stock, preferred stock, warrants, units or guarantees, or a combination of those securities. We may, in one or more offerings, offer and sell common stock, preferred stock, warrants and units. We may also, in one or more offerings, offer and sell senior unsecured and senior subordinated debt securities. Under our shelf registration statement, our senior unsecured and senior subordinated debt securities may be fully and unconditionally guaranteed by KCS Resources, Inc. and Medallion California Properties Company.

During the fourth quarter of 2003, in a public offering under our shelf registration statement, we sold 6.9 million shares of our common stock at $8.00 per share. We used a portion of the net proceeds of approximately $52.0 million to repay borrowings under our bank credit facility and to accelerate our drilling program in certain core areas.

As of December 31, 2004, there was $144.8 million remaining under our shelf registration statement.

Contractual Cash Obligations

The following table summarizes our future contractual cash obligations as of December 31, 2004 (in thousands).

		Payments Due by Period			
Contractual Obligation	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	175,000	—	—	—	175,000
Operating leases	2,201	1,718	483	—	—
Unconditional purchase obligations	3,716	3,037	679	—	—
	180,917	4,755	1,162	—	175,000

The above table does not include the liability for dismantlement, abandonment and restoration cost of oil and gas properties. Please read Note 2 to our Consolidated Financial Statements for further discussion.

Other Commercial Commitments

In connection with the Production Payment, we have obligations to deliver 3.9 Bcfe in 2005 and 0.2 Bcfe in 2006. As of December 31, 2004, we had $2.5 million of surety bonds that remain outstanding until specific events or projects are completed and any claims that may be made are settled.

Off-Balance Sheet Arrangements

We do not utilize and are not currently contemplating using any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions or for any other purpose. Any future transactions involving off-balance sheet arrangements will be scrutinized and disclosed by our management.

New Accounting Principles

The Securities and Exchange Commission issued Staff Accounting Bulletin No. 106, or SAB No. 106, effective October 1, 2004. SAB No. 106 provides interpretive guidance on how full cost companies should reflect asset retirement obligations, or ARO, in their full cost ceiling and depreciation, depletion and amortization expense calculations. SAB No. 106 requires future cash outflows associated with settling ARO's that have accrued on the balance sheet to be excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation. SAB No. 106 also requires the inclusion of the estimated amount of ARO that will be incurred as a future development activity on proved reserves in the costs to be amortized. Since we were already applying the provisions of SAB No. 106, there was no impact on us after adoption.

On December 16, 2004, the Financial Accounting Standards Board, or FASB, issued FASB Statement No. 123 (Revised 2004) "Share-Based Payment," or SFAS 123(R), which is a revision of SFAS Statement No. 123, "Accounting for Stock-Based Compensation." SFAS 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values. We are currently evaluating the impact of this revised standard which is effective on July 1, 2005.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

All information and statements included in this section, other than historical information and statements, are "forward-looking statements." Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Forward-Looking Statements."

Commodity Price Risk

Our major market risk exposure is to oil and natural gas prices, which have historically been volatile. Realized prices are primarily driven by the prevailing worldwide price for crude oil and regional spot prices for natural gas production. We have utilized, and may continue to utilize, derivative contracts, including swaps, futures contracts, options and collars to manage this price risk. We do not enter into derivative or other financial instruments for trading or speculative purposes. While these derivative contracts are structured to reduce our exposure to decreases in the price associated with the underlying commodity, they also limit the benefit we might otherwise receive from price increases. We maintain a system of controls that includes a policy covering authorization, reporting and monitoring of derivative activity.

As of December 31, 2004, we had derivative instruments outstanding covering 8.6 million MMBtu of 2005 natural gas production, 1.4 million MMBtu of 2006 natural gas production and 0.2 million barrels of 2005 oil production, with a fair market value of $1.3 million. In addition, we had commodity basis swaps outstanding covering 0.5 million MMBtu.

As of December 31, 2003, we had derivative instruments outstanding covering 8.8 million MMBtu of 2004 natural gas production and 0.1 million barrels of 2004 oil production, with a fair market value of $0.7 million.

The following table sets forth information with respect to our oil and natural gas hedged position as of December 31, 2004. There were no derivative instruments outstanding beyond the first quarter of 2006.

	Expected Maturity						
	2005					2006	
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total	1st Quarter	Fair Value at December 31, 2004
							(In thousands)
Swaps:							
Oil							
Volumes (bbl)	45,000	45,500	46,000	46,000	182,500	—	$(1,389)
Weighted average price ($/bbl)	$ 36.16	$ 35.22	$ 34.56	$ 33.99	$ 34.98	—	
Natural Gas							
Volumes (MMbtu)	1,800,000	2,275,000	1,380,000	460,000	5,915,000	900,000	$ 2,586
Weighted average price ($/MMbtu)	$ 7.45	$ 6.04	$ 6.37	$ 6.44	$ 6.58	$ 7.30	
Collars:							
Natural Gas							
Volumes (MMbtu)	900,000	455,000	460,000	460,000	2,275,000	450,000	$ 118
Weighted average price ($/MMbtu)							
Floor	$ 5.25	$ 5.50	$ 5.50	$ 5.50	$ 5.40	$ 6.75	
Cap	$ 7.52	$ 7.61	$ 7.61	$ 7.61	$ 7.57	$ 8.25	
Sold calls:							
Natural Gas							
Volumes (MMbtu)	450,000	—	—	—	450,000	—	$ (69)
Weighted average price ($/MMbtu)	$ 7.10	—	—	—	$ 7.10	—	

	Expected Maturity						
	2005					2006	
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total	1st Quarter	Fair Value at December 31, 2004
							(In thousands)
Basis swaps:							
Natural Gas:							
Alberta-AECO to NYMEX							
Volumes (MMbtu)	290,000	—	—	—	290,000	—	$ 4
Weighted average differential ($/MMbtu)	$ (0.95)	—	—	—	$ (0.95)	—	
Natural Gas:							
Texas Eastern Zone M-3 to NYMEX							
Volumes (MMbtu)	232,500	—	—	—	232,500	—	$ 6
Weighted average differential ($/MMbtu)	$ 2.25	—	—	—	$ 2.25	—	
Fair value of derivatives at December 31, 2004							$ 1,256

In addition to the information set forth in the table above, we will deliver 3.9 Bcfe in 2005 and 0.2 Bcfe in 2006 under the Production Payment and amortize deferred revenue at a weighted average discounted price of approximately $4.05 per Mcfe.

During 2004, we delivered approximately 13% of our production under the Production Payment and entered into derivative arrangements designed to reduce price downside risk for approximately 53% of the balance of our production. During 2003, we delivered approximately 20% of our production under the Production Payment and also entered into derivative contracts that covered approximately 20% of the balance of our production.

Commodity Price Swaps. Commodity price swap agreements require us to make payments to, or entitle us to receive payments from, the counter parties based upon the differential between a specified fixed price and a price related to those quoted on the New York Mercantile Exchange for the period involved.

Futures Contracts. Oil or natural gas futures contracts require us to sell and the counter party to buy oil or natural gas at a future time at a fixed price.

Option Contracts. Option contracts provide the right, not the obligation, to buy or sell a commodity at a fixed price. By buying a "put" option, we are able to set a floor price for a specified quantity of our oil or natural gas production. By selling a "call" option, we receive an upfront premium from selling the right for a counter party to buy a specified quantity of oil or natural gas production at a fixed price.

Price Collars. Selling a call option and buying a put option creates a "collar" whereby we establish a floor and ceiling price for a specified quantity of future production. Buying a call option with a strike price above the sold call strike establishes a "3-way collar" that entitles us to capture the benefit of price increases above that call price.

Commodity Basis Swaps. Commodity basis swap agreements require the us to make payments to, or receive payments from, the counterparties based upon the differential between certain pricing indices and a stated differential amount.

Please read Note 11 to our Consolidated Financial Statements for more information regarding our derivatives.

Interest Rate Risk

We use fixed and variable rate long-term debt to finance our capital spending program and for general corporate purposes. Our variable rate debt instruments expose us to market risk related to changes in interest rates. Our fixed rate debt and the associated weighted average interest rate was $175.0 million at 7⅛% as of December 31, 2004 and $125.0 million at 8⅞% as of December 31, 2003. We had no variable rate debt outstanding as of December 31, 2004. Our variable rate debt and weighted average interest rate was $17.0 million at 3.6% as of December 31, 2003.

The tables below present principal cash flows and related average interest rates by expected maturity date for our debt obligations as of December 31, 2004 and 2003 (dollars in millions).

	As of December 31, 2004					
	Expected Maturity Date					
	2005	2006	2007	2008 & Beyond	Total	Fair Value
Long-term debt						
Fixed rate	—	—	—	$175.0	$175.0	$184.2
Average interest rate	—	—	—	7.125%	7.125%	
Variable rate	—	—	—	—	—	—
Average interest rate	—	—	—	—	—	

	As of December 31, 2003				
	Expected Maturity Date				
	2004	2005	2006	Total	Fair Value
Long-term debt					
Fixed rate	—	—	$125.0	$125.0	$130.0
Average interest rate	—	—	8.875%	8.875%	
Variable rate	—	—	$ 17.0	$ 17.0	$ 17.0
Average interest rate	—	—	3.605%	3.605%	

Item 8. ***Financial Statements and Supplementary Data.***

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of KCS, including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, for KCS. Our internal control system was designed to provide reasonable assurance as to the reliability of our financial reporting and the preparation and fair presentation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

Management conducted an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This assessment included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this assessment. Through this assessment, we did not identify any material weaknesses in our internal control over financial reporting. There are inherent limitations in the effectiveness of any system of internal control over financial reporting; however, based on our assessment, we have concluded that our internal control over financial reporting was effective as of December 31, 2004 based on the aforementioned criteria.

Ernst & Young LLP, our independent registered public accounting firm, has issued an attestation report on management's assessment of internal control over financial reporting, which is included on the following page of this report.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of KCS Energy, Inc.:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that KCS Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). KCS Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

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

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

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

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of KCS Energy, Inc. and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2004 and our report dated March 11, 2005 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 11, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of KCS Energy, Inc.:

We have audited the accompanying consolidated balance sheets of KCS Energy, Inc. and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2004. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of KCS Energy, Inc. and subsidiaries as of December 31, 2004 and 2003 and the consolidated results of their operations and their cash flows for each of the three years ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

As described in Note 2, effective January 1, 2002, the company changed its method of accounting for the amortization of its oil and gas properties. In addition, as described in Note 2, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations in accordance with Statement of Financial Accounting Standards No. 143.

We also have audited in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of KCS Energy, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 11, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 11, 2005

KCS ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31,		
	2004	2003	2002
	(Amounts in thousands, except per share data)		
Oil and natural gas revenue	$218,755	$159,826	$120,002
Other, net	(1,466)	5,001	(1,183)
Total revenue and other	217,289	164,827	118,819
Operating costs and expenses			
Lease operating expenses	28,600	24,596	22,878
Production and other taxes	14,208	10,010	7,957
General and administrative expenses	9,123	8,011	8,255
Stock compensation	2,621	2,715	782
Bad debt expense	152	339	215
Accretion of asset retirement obligation	1,029	1,116	—
Depreciation, depletion and amortization	57,309	47,885	49,251
Total operating costs and expenses	113,042	94,672	89,338
Operating income	104,247	70,155	29,481
Interest and other income	317	112	279
Redemption premium on early extinguishment of debt	(3,698)	—	—
Interest expense	(14,336)	(20,970)	(19,945)
Income before income taxes and cumulative effect of accounting change	86,530	49,297	9,815
Federal and state income tax expense (benefit)	(13,905)	(20,229)	13,763
Net income (loss) before cumulative effect of accounting change	100,435	69,526	(3,948)
Cumulative effect of accounting change, net of tax	—	(934)	(6,166)
Net income (loss)	100,435	68,592	(10,114)
Dividends and accretion of issuance costs on preferred stock	—	(909)	(1,028)
Income (loss) available to common stockholders	$100,435	$ 67,683	$(11,142)
Earnings (loss) per share of common stock — basic			
Before cumulative effect of accounting change	$ 2.06	$ 1.73	$ (0.14)
Cumulative effect of accounting change	—	(0.02)	(0.17)
Earnings (loss) per share of common stock — basic	$ 2.06	$ 1.71	$ (0.31)
Earnings (loss) per share of common stock — diluted			
Before cumulative effect of accounting change	$ 2.03	$ 1.63	$ (0.14)
Cumulative effect of accounting change	—	(0.02)	(0.17)
Earnings (loss) per share of common stock — diluted	$ 2.03	$ 1.61	$ (0.31)
Average shares outstanding for computation of earnings (loss) per share			
Basic	48,868	39,579	35,834
Diluted	49,520	42,659	35,834

The accompanying notes are an integral part of these financial statements.

KCS ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2004	December 31, 2003
	(Amounts in thousands, except share and per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 6,613	$ 2,178
Trade accounts receivable, less allowance for doubtful accounts of $4,880 in 2004 and $4,896 in 2003	35,173	23,911
Prepaid drilling	510	1,014
Derivative assets	892	689
Other current assets	2,657	3,017
Current assets	45,845	30,809
Property, plant and equipment		
Oil and gas properties, full cost method, less accumulated DD&A — 2004 $989,930; 2003 $933,572	393,217	283,791
Other property, plant and equipment, at cost less accumulated depreciation — 2004 $12,549; 2003 $11,598	7,788	8,214
Property, plant and equipment, net	401,005	292,005
Deferred charges and other assets		
Deferred taxes	31,713	18,818
Derivative assets	364	—
Other	8,381	1,334
Deferred charges and other assets	40,458	20,152
TOTAL ASSETS	$487,308	$342,966
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 38,772	$ 27,834
Accrued interest	3,118	5,100
Accrued drilling cost	21,922	9,596
Other accrued liabilities	10,775	9,071
Current liabilities	74,587	51,601
Deferred credits and other non-current liabilities		
Deferred revenue	17,326	38,696
Asset retirement obligation	12,655	11,918
Other	691	720
Deferred credits and other non-current liabilities	30,672	51,334
Long-term debt		
Credit facility	—	17,000
Senior notes	175,000	—
Senior subordinated notes	—	125,000
Long-term debt	175,000	142,000
Commitments and contingencies		
Stockholders' equity		
Common stock, par value $0.01 per share, authorized 75,000,000 shares; issued 51,395,536 and 50,532,373, respectively	514	505
Additional paid-in capital	241,545	236,204
Accumulated deficit	(28,197)	(128,632)
Unearned compensation	(1,225)	(725)
Accumulated other comprehensive loss	(847)	(4,580)
Less treasury stock, 2,167,096 shares, at cost	(4,741)	(4,741)
Total Stockholders' equity	207,049	98,031
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$487,308	$342,966

The accompanying notes are an integral part of these financial statements.

KCS ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY (DEFICIT)

	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Unearned Compensation	Accumulated Other Comprehensive Loss	Treasury Stock	Comprehensive Income	(Deficit) Equity
				(Dollars in thousands)				
Balance at December 31, 2001	$368	$162,540	$(185,173)	$(1,292)	$(11,162)	$(4,741)		$(39,460)
Comprehensive income								
Net loss	—	—	(10,114)	—	—	—	$(10,114)	(10,114)
Commodity hedges, net of tax	—	—	—	—	2,661	—	2,661	2,661
Comprehensive income							$ (7,453)	
Conversion of redeemable preferred stock	10	2,932	—	—	—	—		2,942
Stock issuances — benefit plans and awards of restricted stock	4	1,049	—	(370)	—	—		683
Stock compensation expense	—	—	—	782	—	—		782
Dividends and accretion of issuance costs on preferred stock	4	814	(1,028)	—	—	—		(210)
Balance at December 31, 2002	$386	$167,335	$(196,315)	$ (880)	$ (8,501)	$(4,741)		$(42,716)
Comprehensive income								
Net income	—	—	68,592	—	—	—	$ 68,592	68,592
Commodity hedges, net of tax	—	—	—	—	3,921	—	3,921	3,921
Comprehensive income							$ 72,513	
Stock issuances — common stock offering	69	51,926	—	—	—	—		51,995
Conversion of redeemable preferred stock	44	13,244	—	—	—	—		13,288
Stock issuances — benefit plans and awards of restricted stock	5	1,629	—	(655)	—	—		979
Stock compensation expense	—	1,905	—	810	—	—		2,715
Dividends and accretion of issuance costs on preferred stock	1	165	(909)	—	—	—		(743)
Balance at December 31, 2003	$505	$236,204	$(128,632)	$ (725)	$ (4,580)	$(4,741)		$ 98,031
Comprehensive income								
Net income	—	—	100,435	—	—	—	$100,435	100,435
Commodity hedges, net of tax	—	—	—	—	3,733	—	3,733	3,733
Comprehensive income							$104,168	
Stock issuances — exercise of warrants	2	798						800
Stock issuances — cost incurred	—	(221)	—	—	—	—		(221)
Stock issuances — exercise of stock options	5	1,157	—	—	—	—		1,162
Stock issuances — benefit plans and awards of restricted stock	2	1,960	—	(1,474)	—	—		488
Stock compensation expense	—	1,647	—	974	—	—		2,621
Balance at December 31, 2004	$514	$241,545	$ (28,197)	$(1,225)	$ (847)	$(4,741)		$207,049

The accompanying notes are an integral part of these financial statements.

KCS ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31,		
	2004	2003	2002
	(Dollars in thousands)		
Cash flows from operating activities:			
Net income (loss)	$ 100,435	$ 68,592	$(10,114)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	57,309	47,885	49,251
Amortization of deferred revenue	(21,370)	(27,886)	(45,182)
Deferred income tax expense (benefit)	(14,905)	(20,929)	13,763
Cumulative effect of accounting change, net of tax	—	934	6,166
Accretion of asset retirement obligation	1,029	1,116	—
Non-cash losses on derivative instruments	4,540	5,512	5,041
Redemption premium on early debt extinguishment	3,698	—	—
Bad debt expense	152	339	215
Stock compensation	2,621	2,715	782
Other non-cash charges and credits, net	1,354	3,703	1,650
Net changes in assets and liabilities:			
Trade accounts receivable	(11,414)	(7,387)	3,264
Other current assets	360	(1,672)	562
Accounts payable and accrued liabilities	13,005	1,756	(4,122)
Accrued interest	(1,982)	(3,074)	(915)
Other, net	(766)	(582)	464
Net cash provided by operating activities	134,066	71,022	20,825
Cash flows from investing activities:			
Investment in oil and gas properties	(155,406)	(78,126)	(48,596)
Proceeds from the sale of oil and gas properties	867	(153)	30,474
Investment in other property, plant and equipment	(525)	(682)	56
Net cash used in investing activities	(155,064)	(78,961)	(18,066)
Cash flows from financing activities:			
Proceeds from borrowings	175,000	69,295	500
Repayments of debt	(142,000)	(114,069)	(18,526)
Proceeds from common stock offering	—	51,995	—
Deferred financing costs and other, net	(7,567)	(4,039)	(725)
Net cash proved by (used in) financing activities	25,433	3,182	(18,751)
Increase (decrease) in cash and cash equivalents	4,435	(4,757)	(15,992)
Cash and cash equivalents at beginning of year	2,178	6,935	22,927
Cash and cash equivalents at end of year	$ 6,613	$ 2,178	$ 6,935

The accompanying notes are an integral part of these financial statements.

1. Summary of Significant Accounting Policies

KCS Energy, Inc. is an independent oil and gas company engaged in the acquisition, exploration, development and production of natural gas and crude oil with operations predominately in the Mid-Continent and Gulf Coast regions of the United States.

Principles of Consolidation

The consolidated financial statements include the accounts of KCS Energy, Inc. and its wholly-owned subsidiaries ("KCS" or "Company"). The Company consolidates all investments in which it, either through direct or indirect ownership, has more than a fifty percent voting interest and/or control. All significant intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications

Certain previously reported 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 management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash Equivalents

The Company considers as cash equivalents all highly liquid investments with a maturity of three months or less from the date of purchase.

Derivative Instruments

Oil and natural gas prices have historically been volatile. The Company has entered, and may continue to enter, into derivative contracts to manage the risk associated with the price fluctuations affecting it by effectively fixing the price or range of prices of certain sales volumes for certain time periods.

The Company accounts for derivative instruments in accordance with Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133, as amended, establishes accounting and disclosure standards requiring that all derivative instruments be recorded in the balance sheet as an asset or liability, measured at fair value. SFAS No. 133, as amended, further requires that changes in a derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. To qualify as a hedge, these transactions must be formally documented and designated as a hedge and the changes in their fair value must correlate with changes in the expected cash flow from anticipated future sales of production. Changes in the market value of these cash flow hedges are deferred through other comprehensive income, or OCI, until such time as the hedged volumes are produced and sold. Hedge effectiveness is measured at least quarterly based on relative changes in fair value between the derivative contract and the hedged item over time. Any ineffectiveness is immediately reported in other, net in the Statements of Consolidated Operations. If the likelihood of occurrence of a hedged transaction ceases to be "probable", hedge accounting will cease on a prospective basis and all future changes in derivative fair value will be recognized currently in earnings. The net gain or loss from hedges terminated prior to maturity continues to be deferred until the hedged production is recognized in income. If it becomes probable that the hedged transaction will not occur, the derivative gain or loss associated with a terminated derivative will immediately be reclassified from OCI into earnings. If the contract is not designated as a hedge, changes in fair value are recorded to other, net in the Statement of Consolidated Operations.

Fair Value of Financial Instruments

The carrying value of certain financial instruments, including cash, cash equivalents and revolving credit debt approximates estimated fair value due to their short-term maturities and variable interest rates. The estimated fair value of public debt is based upon quoted market values. Derivative financial instruments are carried at fair value.

Property, Plant and Equipment

The Company follows the full cost method of accounting under which all costs incurred in acquisition, exploration and development activities are capitalized in a country-wide cost center. Such costs include lease acquisitions, geological and geophysical services, drilling, completion, equipment and certain salaries, and other internal costs directly associated with acquisition, exploration and development activities. Historically, total capitalized internal costs in any given year have not been material to the total oil and gas costs capitalized in that year. Interest costs related to unproved properties are also capitalized. Salaries, benefits and other internal costs related to production and general overhead are expensed as incurred. Prior to January 1, 2002, the Company utilized the future gross revenue method for providing depreciation, depletion and amortization. Effective January 1, 2002, the Company began providing for depreciation, depletion and amortization, or DD&A, of evaluated costs using the unit-of-production method based on proved reserves, including reserves associated with the Production Payment. Prior to 2003, future development costs and asset retirement obligations were added to the amortizable base. Beginning in 2003, the Company adopted SFAS No. 143 "Accounting for Asset Retirement Obligations" that changed its accounting for dismantlement, restoration and abandonment costs. The Company includes the estimated amount of asset retirement obligations that will be incurred in connection with future development activity on proved reserves in the costs to be amortized. Please read Note 2 to Consolidated Financial Statements for more information about these accounting changes. Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the depreciation, depletion and amortization calculation until a complete evaluation is made and it is determined whether proved reserves can be assigned to the properties or if impairment has occurred. The costs of drilling exploratory dry holes are included in the amortization base immediately upon determination that such wells are dry. Geological and geophysical costs not associated with specific unevaluated properties are included in the amortization base as incurred. Costs of unevaluated properties excluded from amortization were $11.2 million and $6.8 million as of December 31, 2004 and 2003, respectively. The Company will begin to amortize these costs when proved reserves are established or impairment is determined.

The Company performs quarterly "ceiling test" calculations as capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred taxes, are limited to the sum of the present value of estimated future net revenues from proved oil and natural gas reserves at current prices discounted at 10%, plus the lower of cost or fair value of unproved properties, net of related tax effects. To the extent that the capitalized costs exceed this "ceiling" limitation at the end of any quarter, the excess is expensed. Upon the adoption of SFAS No. 143 in the beginning of 2003, the Company began including the capitalized cost of its asset retirement obligations in the oil and gas property balance and excluding the corresponding cash outflow associated with future abandonment cost from future development cost when calculating the pre-tax present value of future net revenues. In September 2004, the SEC issued Staff Accounting Bulletin No. 106 ("SAB No. 106") effectively mandating this treatment. Accordingly, SAB No. 106 had no effect on the Company's accounting.

Proceeds from dispositions of oil and gas properties are credited to the cost center with no recognition of gains or losses unless a significant portion (generally more than 25%) of the Company's proved reserves are sold.

Depreciation of other property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets ranging from 3 to 20 years. Repairs of all property, plant and equipment and replacements and renewals of minor items of property are charged to expense as incurred.

Revenue Recognition

Oil and natural gas revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectibility of the revenue is probable. The Company follows the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold. The volume of natural gas volumes sold may differ from the volume to which the Company is entitled based on its working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under-produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where the Company has taken less than its share of production. Natural gas imbalances are reflected as adjustments to proved natural gas reserves and future cash flows in the unaudited supplemental oil and gas disclosures. Cash received relating to future revenue is deferred and recognized when all revenue recognition criteria have been met.

In February, 2001, the Company sold a 43.1 Bcfe (38.3 Bcf of natural gas and 797,000 barrels of oil) production payment, or Production Payment, to be delivered in accordance with an agreed schedule over a five-year period for net proceeds of approximately $175.0 million. The Company recorded the net proceeds from the sale of the Production Payment as deferred revenue on the balance sheet. Deliveries under this Production Payment are recorded as non-cash oil and natural gas revenue with a corresponding reduction of deferred revenue at the average discounted price per Mcf of natural gas and per barrel of oil received when the Production Payment was sold. The Company also reflects the production volumes and depletion expense as deliveries are made. However, the associated oil and natural gas reserves are excluded from the Company's reserve data. During 2004, the Company delivered 5.2 Bcfe under this Production Payment and recorded $21.4 million of oil and natural gas revenue. During 2003, the Company delivered 6.8 Bcfe under the Production Payment and recorded $27.9 million of oil and gas revenue. During 2002, the Company delivered 11.2 Bcfe under the Production Payment and recorded $45.2 million of oil and gas revenue previously deferred. Since the sale of the Production Payment in February 2001 through December 31, 2004, the Company has delivered 38.9 Bcfe, or 90% of the total quantity to be delivered. For 2005, scheduled deliveries under the Production Payment are 3.9 Bcfe.

Stock Compensation

The cost of awards of restricted stock, determined as the market value of the shares as of the date of grant, is expensed ratably over the restricted period. Stock options issued under the 2001 Stock Plan within six months of the cancellation of options in connection with our plan of reorganization are subject to variable accounting in accordance with Financial Accounting Standards Board Interpretation No. 44, "Accounting for Certain Transaction Involving Stock Compensation." Under variable accounting for stock options, the amount of expense recognized during a reporting period is directly related to the movement in the market price of our common stock during that period. Please read Note 5 for more information on the Company's stock option and incentive plans.

As permitted under SFAS No. 123 "Accounting for Stock-Based Compensation," or SFAS No. 123, as amended, the Company has elected to continue to account for stock options under the provisions of Accounting Principles Board ("APB") Opinion No. 25 "Accounting for Stock Issued to Employees." Under this method, the Company does not record any compensation expense for stock options granted if the exercise price of those options is equal to or greater than the market price of the Company's common stock on the date of grant, unless the awards are subsequently modified. The following table illustrates the effect on income (loss) available to common stockholders and earnings (loss) per share if the Company had applied the fair value recognition provision of SFAS No. 123, as amended.

	2004	2003	2002
	(Amounts in thousands except per share data)		
Earnings (loss) per share			
Income (loss) available to common stockholders as reported	$100,435	$67,683	$(11,142)
Add: Stock-based compensation expense included in reported net income	2,621	2,715	782
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(2,285)	(1,927)	(1,569)
Pro forma income (loss) available to common stockholders	$100,771	$68,471	$(11,929)
Average shares outstanding	48,868	39,579	35,834
Earnings (loss) per share:			
Basic — as reported	$ 2.06	$ 1.71	$ (0.31)
Basic — pro forma	$ 2.06	$ 1.73	$ (0.33)
Diluted earnings (loss) per share			
Income (loss) available to common stockholders as reported	$100,435	$67,683	$(11,142)
Dividends and accretion of issuance costs on preferred stock	—	909	—
Numerator as reported	100,435	68,592	(11,142)
Add: Stock-based compensation expense included in reported net income	2,621	2,715	782
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(2,285)	(1,927)	(1,569)
Pro forma numerator	$100,771	$69,380	$(11,929)
Average diluted shares outstanding	49,520	42,659	35,834
Earnings (loss) per share:			
Diluted — as reported	$ 2.03	$ 1.61	$ (0.31)
Diluted — pro forma	$ 2.03	$ 1.63	$ (0.33)

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts receivable based upon the expected collectibility of all trade receivables. The allowance is reviewed continually and adjusted for accounts deemed uncollectible. The allowance was $4.9 million as of December 31, 2004 and 2003. Included in the allowance is $3.7 million that represents a 79% reserve against receivables from various Enron entities currently in bankruptcy. The Company currently believes that the remaining $1.0 million receivable from such entities will ultimately be recovered based on several factors, including the Company's assessment that a large percentage of its Enron-related receivables should qualify as priority claims in the bankruptcy process.

The Company extends credit, primarily in the form of monthly oil and natural gas sales and joint interest owner receivables, to various companies in the oil and gas industry. These extensions of credit may result in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions and may, accordingly, impact the Company's overall credit risk. However, the Company believes that the risk associated with these receivables is mitigated by the size and reputation of the companies to which the Company extends credit and by dispersion of credit risk among numerous parties.

Income Taxes

The Company accounts for income taxes in accordance with SFAS No. 109 "Accounting for Income Taxes." Deferred income taxes are recorded to reflect the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts as of the end of each year. A valuation allowance is recognized as a charge against earnings if, at the time, it is anticipated that some or all of a deferred tax asset may not be realized.

Common Stock Outstanding

	2004	2003	2002
Balance, beginning of the year	48,365,277	36,444,720	34,677,399
Shares issued for:			
Option and benefit plan, net of forfeited shares	663,163	517,272	413,401
Sale of common shares	200,000	6,900,000	—
Conversion of redeemable preferred stock	—	4,429,317	980,664
Dividends on preferred stock paid in common stock	—	73,968	373,256
Balance, end of year	49,228,440	48,365,277	36,444,720

Segment Reporting

The Company operates in one reportable segment as an independent oil and gas company engaged in the acquisition, exploration, development and production of oil and gas properties. The Company's operations are conducted entirely in the United States.

New Accounting Principles

The SEC issued SAB No. 106. SAB No. 106 provides interpretive guidance on how full cost companies should reflect asset retirement obligations ("ARO") in their full cost ceiling and DD&A calculations. SAB No. 106 requires future cash outflows associated with settling ARO's that have accrued on the balance sheet to be excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation. SAB No. 106 also requires the inclusion of the estimated amount of ARO that will be incurred as a future development activity on proved reserves in the costs to be amortized. As discussed above, the Company had been following this approach. Accordingly, adoption of SAB No. 106 had no impact on the Company.

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

SFAS 123(R) permits public companies to adopt its requirements using one of two methods:

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

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

The Company plans to adopt SFAS 123(R) on July 1, 2005 using the modified-prospective method.

The impact of adoption of SFAS 123(R) on the Company's results of operations cannot be predicted at this time because it will depend on levels of share-based payments granted in the future. However, had we adopted SFAS 123(R) in prior periods, the impact of that standard would have approximated the impact of SFAS 123 as described in the table above. SFAS 123(R) will have no impact on the Company's overall financial position.

2. Accounting Changes

Asset Retirement Obligations

Effective January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the periods in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. The liability is accreted to the fair value at the time of settlement over the useful life of the asset, and the capitalized cost is depreciated over the useful life of the related asset. Upon adoption of SFAS No. 143, the Company's net property, plant and equipment was increased by $10.2 million, an additional asset retirement obligation of $11.1 million (primarily for plugging and abandonment costs of oil and gas wells) was recorded and a $0.9 million charge, net of tax against net income (or a $0.02 loss per basic and diluted share) was reported in the first quarter of 2003 as a cumulative effect of a change in accounting principle. Included in other assets at December 31, 2004 is $2.5 million held in escrow accounts related to certain asset retirement obligations.

The following table illustrates the pro forma effects on income attributable to common stock, earnings per share and asset retirement obligation if the Company had adopted SFAS No. 143 as of January 1, 2002.

	2002
	(Amounts in thousands except per share data)
Income (loss) attributed to common stock:	
As reported	$(11,142)
Pro forma	$(11,659)
Earnings (loss) per share	
Basic — as reported	$ (0.31)
Basic — pro forma	$ (0.33)
Diluted — as reported	$ (0.31)
Diluted — pro forma	$ (0.33)
Pro Forma liability for asset retirement obligation:	
Beginning of year	$ 10,052
End of year	$ 11,142

The following table summarizes the changes in the Company's total estimated liability from the amount recorded upon adoption of SFAS No. 143 on January 1, 2003 through December 31, 2004:

	2004	2003
	(In thousands)	
Asset retirement obligation on January 1,	$11,918	$11,142
Liabilities incurred	245	376
Accretion expense	1,029	1,116
Asset retirement obligation liabilities settled	(764)	(785)
Revisions in estimated liabilities	227	69
Asset retirement obligation on December 31,	$12,655	$11,918

Amortization of Oil and Gas Properties

Effective January 1, 2002, the Company began amortizing the capitalized costs related to oil and gas properties on the unit-of-production, or UOP, method using proved oil and natural gas reserves. Previously, the Company had computed amortization on the basis of future gross revenues, or FGR. The Company determined that the change to UOP was preferable under accounting principles generally accepted in the United States, since among other reasons, it provides a more rational basis for amortization during periods of volatile commodity prices and also increases consistency with others in the industry. As a result of this change, the Company recorded a non-cash cumulative effect charge of $6.2 million, net of tax, (or $0.17 per basic and diluted common share) in the first quarter of 2002. The effect of the change in accounting principle in 2002 was to decrease the net loss by approximately $3.2 million, or $0.09 per basic and diluted share.

3. Earnings (Loss) Per Share

Basic earnings (loss) per share of common stock is computed by dividing income (loss) available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per share of common stock reflects the potential dilution that could occur if the Company's dilutive outstanding stock options and warrants were exercised using the average common stock price for the period and if the Company's convertible preferred stock was converted to common stock.

The following table sets forth information related to the computation of basic and diluted earnings per share:

	2004	2003	2002
	(Amounts in thousands except per share data)		
Basic earnings (loss) per share:			
Income (loss) available to common stockholders	$100,435	$67,683	$(11,142)
Average shares of common stock outstanding	48,868	39,579	35,834
Basic earnings (loss) per share	$ 2.06	$ 1.71	$ (0.31)
Diluted earnings (loss) per share:			
Income (loss) available to common stockholders	$100,435	$67,683	$(11,142)
Dividends and accretion of issuance costs on preferred stock	—	909	n/a
Diluted earnings (loss)	$100,435	$68,592	$(11,142)
Average shares of common stock outstanding	48,868	39,579	35,834
Assumed conversion of convertible preferred stock	—	2,832	n/a
Dividends on convertible preferred stock	—	—	n/a
Stock options and warrants	652	248	n/a
Average diluted shares of common stock outstanding	49,520	42,659	35,834
Diluted earnings (loss) per share	$ 2.03	$ 1.61	$ (0.31)

Shares of common stock issuable upon the assumed conversion of the Company's convertible preferred stock amounting to 4.8 million shares in 2002 were not included in the computation of diluted loss per share nor were accrued dividends on the Company's convertible preferred stock or stock options and warrants as they would be anti-dilutive.

4. Retirement Benefit Plan

The Company sponsors a Savings and Investment Plan, or Savings Plan, under Section 401(k) of the Internal Revenue Code. Eligible employees may contribute a portion of their compensation, as defined under the Savings Plan, to the Savings Plan, subject to certain Internal Revenue Service limitations. The Company may make matching contributions, which have been set by the Company's board of directors at 50% of the employee's contribution (up to 6% of the employee's compensation, subject to certain regulatory limitations). The Savings Plan also contains a profit-sharing component whereby the Company's board of directors may declare annual discretionary profit-sharing contributions. Profit-sharing contributions are allocated to eligible employees based upon their pro-rata share of total eligible compensation and may be made in cash or in shares of the Company's common stock. Contributions to the Savings Plan are invested at the direction of the employee in one or more funds or can be directed to purchase common stock of the Company at market value. The Company's matching contributions and discretionary profit-sharing contributions vest over a four-year employment period. Once the four-year employment period has been satisfied, all Company matching contributions and discretionary profit-sharing contributions immediately vest. Company contributions to the Savings Plan were $633,818 in 2004, $524,419 in 2003 and $531,103 in 2002.

5. Stock Option and Incentive Plans

The KCS Energy, Inc. 2001 Employees and Directors Stock Plan, or 2001 Stock Plan, provides that stock options, stock appreciation rights, restricted stock and bonus stock may be granted to employees of the

Company. The 2001 Stock Plan also provides that annually, each non-employee director receive shares of the Company's common stock with a fair market value equal to 50% of their annual retainer in lieu of cash and grants of stock options for 1,000 shares. The 2001 Stock Plan provides that the option price of shares issued be equal to the market price on the date of grant. Options granted to directors as part of their annual compensation vest immediately. All other options vest ratably on the anniversary of the date of grant over a period of time, typically three years. All options expire 10 years after the date of grant. On February 20, 2001, in connection with the Plan of Reorganization, the Company's 1992 Stock Plan and the 1994 Directors' Stock Plan and all outstanding options thereunder were cancelled. Options issued under the 2001 Stock Plan within six months of this cancellation are subject to variable accounting in accordance with Financial Accounting Standards Board Interpretation No. 44, "Accounting for Certain Transaction Involving Stock Compensation." Under variable accounting for stock options, the amount of expense recognized during a reporting period is directly related to the movement in the market price of the Company's common stock during that period. During 2004 and 2003, the Company recorded $1.6 million and $1.9 million respectively as stock compensation in the Statements of Consolidated Operations related to the options subject to variable accounting. The Company did not record any stock compensation expense related to stock options in 2002 since the stock options were "out of the money."

Restricted shares awarded under the 2001 Stock Plan have a restriction period of three years. During the restriction period, ownership of the shares cannot be transferred and the shares are subject to forfeiture if employment terminates before the end of the restriction period. Certain restricted stock awards provide for the restriction period to accelerate to one year if certain performance criteria are met. Restricted stock is considered to be currently issued and outstanding and has the same rights as other common stock. The cost of the awards of restricted stock, determined as the market value of the shares at the date of grant, is expensed ratably over the restricted period. As of December 31, 2004, there were 586,279 outstanding shares of restricted stock.

As of December 31, 2004, a total of 977,606 shares were available for future grants under the 2001 Stock Plan.

A summary of the status of the stock options under the 2001 Stock Plan as of December 31, 2004, 2003, and 2002 and changes during the years then ended is presented in the table below. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants in 2004: (1) risk-free interest rate of 4.47%; (2) expected dividend yield of 0.00%; (3) expected life of 10 years; and (4) expected stock price volatility of 90.7%. The weighted average assumptions used for grants in 2003 were: (1) risk-free interest rate of 3.67%; (2) expected dividend yield of 0.00%; (3) expected life of 10 years; and (4) expected stock price volatility of 88.6%. The weighted average assumptions used for grants in 2002 were: (1) risk-free interest rate of 5.3%; (2) expected dividend yield of 0.00%; (3) expected life of 10 years; and (4) expected stock price volatility of 86.7%.

	2004		2003		2002	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,885,722	$ 4.36	1,564,761	$4.73	1,229,043	$5.49
Granted	174,500	11.88	527,500	3.54	501,000	2.75
Exercised	(560,273)	4.53	(96,057)	5.17	—	—
Forfeited	(20,142)	4.62	(110,482)	5.02	(165,282)	4.42
Outstanding at end of year	1,479,807	5.17	1,885,722	4.36	1,564,761	4.73
Exercisable at end of year	834,262	$ 4.88	868,723	$5.13	494,522	$5.56
Weighted average fair value of options granted		$10.45		$3.07		$2.39

The following table summarizes information about stock options outstanding as of December 31, 2004.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2004	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2004	Weighted Average Exercise Price
$1.71 - $ 5.20	517,342	8.00	$ 2.38	206,297	$ 2.57
5.21 - 6.00	783,965	6.81	5.51	618,965	5.56
6.01 - 9.61	5,000	6.39	9.61	5,000	9.61
9.62 - 13.30	173,500	9.26	11.88	4,000	12.41
$1.71 - $13.30	1,479,807	7.51	$ 5.17	834,262	$ 4.88

The Company has an employee stock purchase program, or Program. Under the Program, all eligible employees and directors may purchase full shares from the Company at a price per share equal to 90% of the market value determined by the closing price on the date of purchase. The minimum purchase is 25 shares. The maximum annual purchase is the number of shares costing no more than 10% of the eligible employee's annual base salary. The maximum annual purchase for directors is 6,000 shares. The number of shares issued in connection with the Program was 2,525 shares, 19,394 shares and 8,209 shares during 2004, 2003 and 2002, respectively. As of December 31, 2004, there were 754,070 shares available for issuance under the Program.

6. Debt

The following table sets forth information regarding the Company's outstanding debt.

	December 31, 2004	December 31, 2003
	(Amounts in thousands)	
Bank Credit Facility	$ —	$ 17,000
$8\frac{7}{8}$% Senior Subordinated Notes	—	125,000
$7\frac{1}{8}$% Senior Notes	175,000	—
	175,000	142,000
Classified as short-term debt	—	—
Long-term debt	$175,000	$142,000

Bank Credit Facility. The Company has a bank credit facility that provides up to $100 million of revolving borrowing capacity and matures on November 20, 2006. Borrowing capacity under the bank credit facility is subject to a borrowing base (currently $100 million) and is reviewed at least semi-annually and may be adjusted based on the lenders' valuation of the Company's oil and natural gas reserves and other factors. Substantially all of the Company's assets, including the stock of all of its subsidiaries, are pledged to secure the bank credit facility. Further, each of the Company's subsidiaries has guaranteed its obligations under the bank credit facility.

Effective December 1, 2004, borrowings under the bank credit facility bear interest, at the Company's option, at an interest rate of LIBOR plus 1.75% to 2.5% or the greater of (1) the Federal Funds Rate plus 0.5% or (2) the Base Rate, plus 0.0% to 0.75%, depending on utilization. These rates will decrease by 0.5% after the final deliveries are made in connection with the Production Payment entered into by the Company in 2001 and the lien on the subject property is released. Also effective December 1, 2004, a commitment fee of 0.35% to 0.5% per year, depending on utilization, is paid on the unused availability under the bank credit facility. From November 18, 2003 through November 30, 2004, the applicable margin for LIBO rate loans was 2.25% to 3.0%, the applicable margin for base rate loans was 0.5% to 1.25%, depending on utilization and the commitment fee was 0.5% per year on the unused availability under the credit facility.

The bank credit facility contains various restrictive covenants, including minimum levels of liquidity and interest coverage. The bank credit facility also contains other usual and customary terms and conditions of a conventional borrowing base facility, including prohibitions on a change of control, prohibitions on the payment of cash dividends, restrictions on certain other distributions and restricted payments, and limitations on the incurrence of additional debt and the sale of assets.

As of December 31, 2004, we did not have any outstanding amounts under the bank credit facility and had $100 million of unused borrowing capacity available for future financing needs. In addition, the Company was in compliance with all covenants under the bank credit facility as of that date.

Senior Notes. On April 1, 2004, the Company issued $175 million of $7\frac{1}{8}$% senior notes due April 1, 2012 (the "Senior Notes"). The Senior Notes bear interest at a rate of $7\frac{1}{8}$% per annum with interest payable semi-annually on April 1 and October 1. The Company may redeem the Senior Notes at its option, in whole or in part, at any time on or after April 1, 2008 at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium which decreases yearly from 3.563% in 2008 to 0% in 2010 and thereafter. In addition, at any time prior to April 1, 2007, the Company may redeem up to a maximum of 35% of the aggregate principal amount with the net cash proceeds of one or more equity offerings at a price equal to 107.125% of the principal amount, plus accrued and unpaid interest. The Senior Notes are senior unsecured obligations and rank subordinate in right of payment to all existing and future secured debt, including secured debt under the Company's bank credit facility, and will rank equal in right of payment to all existing and future senior indebtedness.

The Senior Notes are jointly and severally and fully and unconditionally guaranteed on a senior unsecured basis by all of the Company's current subsidiaries. KCS Energy, Inc., the issuer of the Senior Notes, has no independent assets or operations apart from the assets and operations of its subsidiaries.

The indenture governing the Senior Notes contains covenants that, among other things, restricts or limits the ability of the Company and the subsidiary guarantors to: (i) borrow money; (ii) pay dividends on stock; (iii) purchase or redeem stock or subordinated indebtedness; (iv) make investments; (v) create liens; (vi) enter into transactions with affiliates; (vii) sell assets; and (viii) merge with or into other companies or transfer all or substantially all of the Company's assets.

In addition, upon the occurrence of a change of control (as defined in the indenture governing the Senior Notes), the holders of the Senior Notes will have the right to require the Company to repurchase all or any part of the Senior Notes at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any.

The Company received $171.1 million in net proceeds from the issuance of the Senior Notes. Net proceeds of the issuance were used to redeem the aggregate principal amount of the Company's $125 million 8⅞% senior subordinated notes due 2006 (the "Senior Subordinated Notes") together with an early redemption premium of $3.7 million, to repay the $22 million outstanding under the Company's bank credit facility, and for general corporate purposes.

The Senior Subordinated Notes were redeemed on May 1, 2004 and the early redemption premium of $3.7 million was charged against earnings in the second quarter of 2004. In addition, the Company incurred an additional $0.9 million of interest expense as both the Senior Subordinated Notes and the Senior Notes were outstanding during the month of April 2004.

Other Information

The estimated fair value of the Company's Senior Notes was $184.2 million based on quoted market values at December 31, 2004. The estimated fair value of the Company's Senior Subordinated Notes was $130.0 million based on quoted market values at December 31, 2003.

None of the Company's outstanding debt at December 31, 2004 is scheduled to mature during the next five years.

Total interest payments were $15.3 million in 2004, $18.6 million in 2003 and $19.2 million in 2002. Capitalized interest was $0.6 million in 2004, $0.4 million in 2003 and $0.7 million in 2002.

7. Shelf Registration Statement/Common Stock Offering

On September 16, 2003, KCS Energy, Inc., along with two of its operating subsidiaries, KCS Resources, Inc. and Medallion California Properties Company, filed a $200 million universal shelf registration statement with the Securities and Exchange Commission. The shelf registration statement covers the issuance of an unspecified amount of senior unsecured debt securities, senior subordinated debt securities, common stock, preferred stock, warrants, units or guarantees, or a combination of those securities. The Company may, in one or more offerings, offer and sell common stock, preferred stock, warrants and units. The Company may also, in one or more offerings, offer and sell senior unsecured and senior subordinated debt securities. Under the Company's shelf registration statement, its senior unsecured and senior subordinated debt securities may be fully and unconditionally guaranteed by KCS Resources, Inc. and Medallion California Properties Company.

On November 26, 2003, in a public offering under our shelf registration statement, the Company sold 6.0 million shares of its common stock at $8.00 per share. On December 11, 2003, the underwriters exercised their over-allotment option and the Company sold an additional 0.9 million shares of common stock at $8.00 per share. As of December 31, 2004, there was $144.8 million remaining under our shelf registration statement.

8. Redeemable Convertible Preferred Stock

On September 15, 2003, the Company issued a redemption notice to holders of its Series A Convertible Preferred Stock in accordance with the provisions in the Certificate of Designation, Preferences, Rights and Limitations of the Preferred Stock, or Certificate of Designation. Under the Certificate of Designation, the Company had the option to redeem the Preferred Stock if the closing price of the Company's common stock exceeded $6.00 per share for 25 out of 30 consecutive trading days. The redemption date was set as October 15, 2003. Prior to the redemption date, holders of 100% of the outstanding Preferred Stock exercised their conversion rights.

Background. In February 2001, the Company issued 30,000 shares of Series A Convertible Preferred Stock, $0.01 par value, or Preferred Stock, at a price of $1,000 per share. The Preferred Stock was convertible at any time into a total of 10,000,000 shares of the Company's common stock at a conversion price of $3.00 per share. Net proceeds from the issuance of the Preferred Stock were $28.4 million. The excess of the redemption value of the Preferred Stock over the original net issuance proceeds is reflected as accretion of issuance costs on preferred stock in the Statements of Consolidated Operations. A dividend of 5% per year was paid quarterly in cash or, during the first two years following issuance, in shares of the Company's common stock valued at the average of the high and the low trading price for the twenty trading days prior to the dividend payment date. While outstanding, the Preferred Stock had no voting rights except upon certain defaults or failure to pay dividends and as otherwise required by law. The Preferred Stock had a liquidation preference of $1,000 per share plus accrued and unpaid dividends and ranked senior to common stock or any subsequent issue of preferred stock.

In connection with the issuance of the Preferred Stock, the Company also issued warrants to the placement agent to purchase 400,000 shares of the Company's common stock at $4.00 per share. In January 2004, one half of the warrants were exercised and the remaining warrants were exercised in March 2005.

As a result of conversions of the Preferred Stock, 4.4 million and 1.0 million shares of common stock were issued in 2003 and 2002, respectively. In addition 0.4 million shares of common stock were issued as dividends on the preferred stock in 2002.

9. Leases and Unconditional Purchase Obligations

Future minimum lease payments under operating leases having initial or remaining non-cancelable lease terms in excess of one year are as follows: (1) $1.7 million in 2005; (2) $0.4 million in 2006; and (3) less than $0.1 million after 2006. Lease payments charged to operating expenses amounted to $2.0 million, $1.7 million and $1.3 million during 2004, 2003 and 2002, respectively. In addition, the Company has unconditional purchase obligations, primarily related to natural gas transportation contracts, of $3.0 million in 2005 and $0.7 million in 2006.

10. Income Taxes

Federal and state income tax provision (benefit) includes the following components:

	For the Year Ended December 31, 2004	2003	2002
	(Dollars in thousands)		
Current provision	$ 1,000	$ 700	$ —
Deferred provision (benefit), net	(14,905)	(20,929)	12,937
Federal income tax provision (benefit)	(13,905)	(20,229)	12,937
State income tax provision (deferred provision $0 in 2004 and 2003, $826 in 2002)	—	—	826
	$(13,905)	$(20,229)	$13,763
Reconciliation of federal income tax expense (benefit) at statutory rate to provision for income taxes:			
Income before income taxes	$ 86,530	$ 49,297	$ 9,815
Tax provision at 35% statutory rate	30,286	17,254	3,435
Change in valuation allowance	(44,167)	(37,560)	9,776
State income taxes, net of federal benefit	—	—	537
Other, net	(24)	77	15
	$(13,905)	$(20,229)	$13,763

The primary differences giving rise to the Company's net deferred tax assets are as follows:

	December 31, 2004	2003
	(Dollars in thousands)	
Income tax effects of:		
Deferred tax assets		
Alternative minimum tax credit carry forwards	$ 4,476	$ 3,476
Net operating loss carry forward	56,709	60,671
Statutory depletion carryforward	400	400
Bad debts	1,708	1,756
Deferred revenue	146	260
Other comprehensive income	456	2,466
Other	29	2,344
Gross deferred tax asset	63,924	71,373
Valuation allowance	—	(44,167)
Deferred tax assets	63,924	27,206
Deferred tax liabilities		
Property related items	(32,211)	(8,388)
Deferred tax liabilities	(32,211)	(8,388)
Net deferred tax asset	$ 31,713	$ 18,818

Federal alternative minimum tax payments, or AMT, of $1.0 million and $0.7 million were made in 2004 and 2003, respectively. No federal income tax payments were made during 2002. There were no state income tax payments in 2004 or 2003. State income tax payments were $0.5 million in 2002.

The Company records deferred tax assets and liabilities to account for temporary differences arising from events that have been recognized in its financial statements and will result in future taxable or deductible items in its tax returns. To the extent deferred tax assets exceed deferred tax liabilities, at least annually and more frequently if events or circumstances change materially, the Company assesses the realizability of its net deferred tax assets. A valuation allowance is recognized if, at the time, it is anticipated that some or all of the net deferred tax assets may not be realized.

In making this assessment, management performs an extensive analysis of the operations of the Company to determine the sources of future taxable income. Such an analysis consists of a detailed review of all available data, including the Company's budget for the ensuing year, forecasts based on current as well as historical prices, and the Company's oil and gas reserve report.

The determination to establish and adjust a valuation allowance requires significant judgment as the estimates used in preparing budgets, forecasts and reserve reports are inherently imprecise and subject to substantial revision as a result of changes in the outlook for prices, production volumes and costs, among other factors. It is difficult to predict with precision the timing and amount of taxable income the Company will generate in the future. Accordingly, while the Company's current net operating loss carryforwards aggregating approximately $162.0 million have remaining lives ranging from 14 to 18 years, management examines a much shorter time horizon, usually two to three years, when projecting estimates of future taxable income and making the determination as to whether the valuation allowance should be adjusted.

During the second quarter of 2002, uncertainty resulting from relatively low commodity prices and the January 2003 maturity date for our senior notes led management to increase the valuation allowance by $15.9 million. This increase in the valuation allowance reduced the carrying value of net deferred assets to zero. Since that time, the Company has generated significant levels of taxable income due to drilling success and strong natural gas and oil prices. The Company believes that its future outlook for continued generation of taxable income is positive based on existing available information, including current prices quoted on the New York Mercantile Exchange. Therefore, during 2003, the Company reversed approximately $37.6 million of the valuation allowance and in 2004 reversed the remaining $44.2 million of the valuation allowance related to expected taxes on future years' taxable income.

As of December 31, 2004, the Company had tax net operating losses, or NOLs, of approximately $162.0 million available to offset future taxable income, including approximately $73.8 million that will expire in 2018, $34.1 million that will expire in 2019, $26.0 million that will expire in 2020 and $28.1 million that will expire in 2022.

11. Derivatives

Oil and natural gas prices have historically been volatile. The Company has at times utilized derivative contracts, including swaps, futures contracts, options and collars, to manage this price risk.

Commodity Price Swaps. Commodity price swap agreements require the Company to make payments to, or entitle it to receive payments from, the counter parties based upon the differential between a specified fixed price and a price related to those quoted on the New York Mercantile Exchange for the period involved.

Futures Contracts. Oil or natural gas futures contracts require the Company to sell and the counter party to buy oil or natural gas at a future time at a fixed price.

Option Contracts. Option contracts provide the right, not the obligation, to buy or sell a commodity at a fixed price. By buying a "put" option, the Company is able to set a floor price for a specified quantity of its oil or natural gas production. By selling a "call" option, the Company receives an upfront premium from selling the right for a counter party to buy a specified quantity of oil or natural gas production at a fixed price.

Price Collars. Selling a call option and buying a put option creates a "collar" whereby the Company establishes a floor and ceiling price for a specified quantity of future production. Buying a call option with a strike price above the sold call strike price establishes a "3-way collar" that entitles the Company to capture the benefit of price increases above that call price.

Commodity Basis Swaps. Commodity basis swap agreements require the Company to make payments to, or receive payments from, the counter parties based upon the differential between certain pricing indices and a stated differential amount.

As of December 31, 2004, the Company had derivative instruments outstanding covering 8.6 million MMBtu of 2005 natural gas production, 1.4 million MMBtu of 2006 natural gas production, and 0.2 million barrels of 2005 oil production with a fair market value of $1.3 million. In addition, there were commodity basis swaps outstanding covering 0.5 million MMBtu. The following table sets forth the Company's oil and natural gas hedged position as of December 31, 2004.

	Expected Maturity						
	2005					2006	
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total	1st Quarter	Fair Value at December 31, 2004
							(In thousands)
Swaps:							
Oil							
Volumes (bbl)	45,000	45,500	46,000	46,000	182,500	—	$(1,389)
Weighted average price ($/bbl)	$ 36.16	$ 35.22	$ 34.56	$ 33.99	$ 34.98	—	
Natural Gas							
Volumes (MMbtu)	1,800,000	2,275,000	1,380,000	460,000	5,915,000	900,000	$ 2,586
Weighted average price ($/MMbtu)	$ 7.45	$ 6.04	$ 6.37	$ 6.44	$ 6.58	$ 7.30	
Collars:							
Natural Gas							
Volumes (MMbtu)	900,000	455,000	460,000	460,000	2,275,000	450,000	$ 118
Weighted average price ($/MMbtu)							
Floor	$ 5.25	$ 5.50	$ 5.50	$ 5.50	$ 5.40	$ 6.75	
Cap	$ 7.52	$ 7.61	$ 7.61	$ 7.61	$ 7.57	$ 8.25	
Sold calls:							
Natural Gas							
Volumes (MMbtu)	450,000	—	—	—	450,000	—	$ (69)
Weighted average price ($/MMbtu)	$ 7.10	—	—	—	$ 7.10	—	
Basis swaps:							
Natural Gas:							
Alberta-AECO to NYMEX							
Volumes (MMbtu)	290,000	—	—	—	290,000	—	$ 4
Weighted average differential ($/MMbtu)	$ (0.95)	—	—	—	$ (0.95)	—	
Natural Gas:							
Texas Eastern Zone M-3 to NYMEX							
Volumes (MMbtu)	232,500	—	—	—	232,500	—	$ 6
Weighted average differential ($/MMbtu)	$ 2.25	—	—	—	$ 2.25	—	
Fair value of derivatives at December 31, 2004							$ 1,256

The Company realized $8.6 million in net hedging losses during 2004, of which $4.5 million was net hedging losses due to reclassifications from OCI for contracts terminated in 2001 and $4.1 million was from other commodity derivatives accounted for as hedges pursuant to SFAS 133. During 2003, the Company realized $6.2 million in net hedging losses, including $5.5 million net hedging losses due to reclassifications from OCI for contracts terminated in 2001. During 2002, the Company realized $4.9 million in net hedging losses including $5.0 million net hedge losses due to reclassifications from OCI from contracts terminated prior to January 1, 2002.

The fair value of the Company's derivative instruments are reflected as assets or liabilities in the Company's financial statements as presented in the following table.

	December 31, 2004
	(In thousands)
Derivative assets — current	$ 892
Derivative assets — non current	364
Fair value of derivatives at December 31, 2004	$1,256

In addition to the information set forth in the first table above, the Company will deliver 3.9 Bcfe in 2005 and 0.2 Bcfe in 2006 under the Production Payment sold in February 2001 and amortize deferred revenue at a weighted average discounted price of $4.05 per Mcfe.

As of December 31 2004, the Company had approximately $0.8 million of derivative losses, net of tax, recorded in Accumulated Other Comprehensive Income (Loss) ("AOCI") which included losses associated with terminated commodity derivatives and other commodity derivatives. The following table recaps the balance of AOCI at December 31, 2004 on both a pre-tax and after-tax basis.

	Pre-tax	After-tax
	(In thousands)	
Terminated commodity derivatives(a)	$(3,026)	$(1,967)
Other commodity derivatives(b)	1,723	1,120
AOCI at December 31, 2004	$(1,303)	$ (847)

(a) During 2001, the Company terminated certain commodity derivative instruments and recognized a charge to AOCI. As the original forecasted transaction occurs, this loss is reclassified as a charge against earnings. The following table details the activity of these terminated commodity instruments on both a pre-tax and after-tax basis.

	Pre-tax	After-tax
	(In thousands)	
Balance included in AOCI, December 31, 2003	$(7,566)	$(4,918)
Reclassified as a charge against earnings	4,540	2,951
Balance included in AOCI, December 31, 2004	$(3,026)	$(1,967)

The $2.0 million after-tax loss remaining in AOCI at December 31, 2004 related to the terminated commodity derivatives, will be reclassified as a charge against earnings in 2005.

(b) The Company also has other commodity derivatives, which were accounted for as hedges pursuant to SFAS No. 133. The following table details the activity of those commodity derivatives on both a pre-tax and after-tax basis.

	Pre-tax	After-tax
	(In thousands)	
Balance included in AOCI, December 31, 2003	$ 520	$ 338
Reclassified into earnings	4,093	2,661
Change in fair market value	(3,529)	(2,294)
Ineffective portion of hedges	639	415
Balance included in AOCI, December 31, 2004	$ 1,723	$ 1,120

12. Litigation

The Company and several of its subsidiaries have been named as co-defendants along with numerous other industry parties in an action brought by Jack Grynberg on behalf of the Government of the United States. The complaint, filed under the Federal False Claims Act in the United States District Court for the District of Wyoming, alleges underpayment of royalties to the Government of the United States as a result of alleged mismeasurement of the produced natural gas volume and wrongful analysis of the heating content of natural gas produced from federal and Native American lands. The complaint is substantially similar to other complaints filed by Jack Grynberg on behalf of the Government of the United States against multiple other industry parties. All of the complaints have been consolidated into one proceeding. In April 1999, the Government of the United States filed notice that it had decided not to intervene in these actions. The plaintiff has not specified any damages related to the Company's properties. The Company believes that the allegations in the complaint are without merit.

The Company is also a party to various other lawsuits and governmental proceedings, all arising in the ordinary course of business. Although the outcome of these proceedings and the Grynberg proceeding cannot be predicted with certainty, management does not expect such matters to have a material adverse effect, either individually or in the aggregate, on the financial condition or results of operations of the Company. It is possible, however, that charges could be required that would be significant to the operating results during a particular period.

13. Quarterly Financial Data (Unaudited)

	Quarters			
	First	Second	Third	Fourth
	(Dollars in thousands, except per share data)			
2004				
Revenue and other	$50,444	$50,641	$51,283	$64,921
Operating income	$24,444	$23,240	$23,743	$32,820
Net income	$19,445	$14,497	$18,818	$47,675
Basic earnings per common share	$ 0.40	$ 0.30	$ 0.38	$ 0.97
Diluted earnings per common share	$ 0.39	$ 0.29	$ 0.38	$ 0.96

	Quarters			
	First	Second	Third	Fourth
2003				
Revenue and other	$40,440	$42,732	$40,671	$40,984
Operating income	$18,941	$20,732	$16,122	$14,360
Net income	$13,902	$27,301	$11,681	$15,708
Basic earnings per common share	$ 0.36	$ 0.71	$ 0.30	$ 0.35
Diluted earnings per common share	$ 0.34	$ 0.66	$ 0.28	$ 0.35

The total of the earnings per share for the quarters may not equal the earnings per share elsewhere in the Consolidated Financial Statements as each quarterly computation is based on the weighted average number of common shares outstanding during that period.

14. Oil and Natural Gas Producing Operations (Unaudited)

The following data is presented pursuant to SFAS No. 69 "Disclosure about Oil and Gas Producing Activities" with respect to oil and natural gas acquisition, exploration, development and producing activities and is based on estimates of year-end oil and natural gas reserve quantities and forecasts of future development costs and production schedules. These estimates and forecasts are inherently imprecise and subject to substantial revision as a result of changes in estimates of remaining volumes, prices, costs and production rates.

Except where otherwise provided by contractual agreement, future cash inflows are estimated using year-end prices. Oil and natural gas prices as of December 31, 2004 are not necessarily reflective of the prices the Company expects to receive in the future. Other than natural gas sold under contractual arrangements, natural gas prices were based on year-end spot market prices of $6.18, $5.97 and $4.74 per MMBtu, adjusted by lease for Btu content, transportation fees and regional price differentials as of December 31, 2004, 2003 and 2002, respectively. Oil prices were based on West Texas Intermediate, or WTI, posted prices of $40.25, $29.25 and $28.00 as of December 31, 2004, 2003 and 2002, respectively, adjusted by lease for gravity, transportation fees and regional price differentials. Hedge-adjusted prices are not considered for purposes of calculating future cash inflows.

Oil and natural gas reserves have been reduced to reflect the sale of the Production Payment of 38.3 Bcf of natural gas and 797,000 barrels of oil in 2001 as discussed in Note 1.

Production Revenues and Costs (Unaudited)

Information with respect to production revenues and costs related to oil and natural gas producing activities are set forth in the following table.

	For the Year Ended December 31,		
	2004	2003	2002
	(Dollars in thousands)		
Revenue(a)	$ 218,755	$ 159,826	$ 120,002
Production (lifting) costs and taxes	42,808	34,606	30,835
Technical support and other	1,993	1,738	3,198
Depreciation, depletion and amortization(b)	58,254	48,908	49,120
Total expenses	103,055	85,252	83,153
Pretax income from producing activities	115,700	74,574	36,849
Income tax expense (benefit)	(13,905)	(20,229)	13,763
Results of oil and gas producing activities (excluding corporate overhead and interest)	$ 129,605	$ 94,803	$ 23,086
Depreciation, depletion and amortization rate per Mcfe	$ 1.46	$ 1.41	$ 1.31
Capitalized costs incurred:			
Property acquisition	$ 6,875	$ (159)	$ 4,822
Exploration	27,177	10,067	12,428
Development(c)	132,599	78,646	30,314
Total capitalized costs incurred	$ 166,651	$ 88,554	$ 47,564
Capitalized costs at year end:			
Proved properties	$1,371,908	$1,210,594	$1,119,339
Unproved properties	11,239	6,769	3,364
	1,383,147	1,217,363	1,122,703
Less accumulated depreciation, depletion and amortization	(989,930)	(933,572)	(891,124)
Net investment in oil and gas properties	$ 393,217	$ 283,791	$ 231,579

(a) Includes amortization of deferred revenue of $21,370 in 2004, $27,886 in 2003, and $45,182 in 2002 related to volumes delivered under the Production Payment sold in February 2001. See Note 1.

(b) Includes accretion of asset retirement obligation of $1,029 in 2004 and $1,116 in 2003 as a result of adoption of SFAS 143. See Note 2.

(c) Includes the asset retirement costs incurred during the year.

Discounted Future Net Revenues (Unaudited)

The following information relating to discounted future net revenues has been prepared on the basis of the Company's estimated net proved oil and natural gas reserves in accordance with SFAS No. 69.

Discounted Future Net Revenues Relating to Proved Oil and Gas Reserves

	December 31, 2004	December 31, 2003	December 31, 2002
	(Dollars in thousands)		
Future cash inflows	$2,033,609	$1,556,851	$ 908,031
Future costs:			
Production	(480,675)	(369,497)	(279,282)
Development(a)	(170,954)	(117,726)	(58,253)
Future income taxes	(317,842)	(229,892)	(49,203)
Future net revenues	1,064,138	839,736	521,293
Discount — 10%	(412,750)	(323,463)	(199,077)
Standardized measure of discounted future net cash flows	$ 651,388	$ 516,273	$ 322,216

Changes in Discounted Future Net Revenues from Proved Reserve Quantities

	For the Year Ended December 31, 2004	2003	2002
	(Dollars in thousands)		
Balance, beginning of year	$ 516,273	$ 322,216	$202,188
Increases (decreases)			
Sales, net of production costs	(163,210)	(103,527)	(48,878)
Net change in prices, net of production costs	18,327	79,455	135,290
Discoveries and extensions, net of future production and development costs	232,046	252,501	66,487
Changes in estimated future development costs	(4,006)	(2,952)	13,636
Change due to acquisition of reserves in place	9,823	102	11,945
Development costs incurred during the period	47,607	28,978	6,868
Revisions of quantity estimates	10,891	24,916	(38,541)
Accretion of discount	62,997	32,222	20,219
Net change in income taxes	(48,723)	(92,391)	(21,306)
Sales of reserves in place	(592)	(6,450)	(24,842)
Changes in production rates (timing) and other	(30,045)	(18,797)	(850)
Net increase (decrease)	135,115	194,057	120,028
Balance, end of year(b)	$ 651,388	$ 516,273	$322,216

(a) Includes the cash outflows associated with asset retirement obligations.

(b) Excludes $21,370, $27,886 and $66,582 of deferred revenue at December 31, 2004, 2003 and 2002, respectively, related to the Production Payment sold in 2001 as discussed in Note 1.

Reserve Information (Unaudited)

The reserve estimates and associated revenues for all properties for the years ended December 31, 2004 and 2003 were prepared by the Company and audited by Netherland, Sewell & Associates, Inc., or NSAI. For the year ended December 31, 2002, the reserve estimates and associated revenues for all properties were prepared by NSAI. Proved oil and gas reserves are estimated by the Company in accordance with the Securities and Exchange Commission's definitions in Rule 4-10(a) of Regulation S-X. These definitions can be found on the SEC website at http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas. All of the Company's reserves are located within the United States.

	2004		2003		2002	
	Natural Gas MMcf	Oil Mbbl	Natural Gas MMcf	Oil Mbbl	Natural Gas MMcf	Oil Mbbl
Proved developed and undeveloped reserves						
Balance, beginning of year	228,118	6,695	154,993	6,772	190,141	6,644
Production(a)	(29,209)	(932)	(22,102)	(972)	(19,733)	(1,082)
Discoveries, extensions, etc.	82,245	873	89,691	681	25,777	1,043
Acquisition of reserves in place	2,864	11	49	—	6,253	161
Sales of reserves in place(b)	(301)	(18)	(1,963)	(293)	(21,406)	(879)
Revisions of estimates	4,201	(19)	7,450	507	(26,039)	885
Balance, end of year	287,918	6,610	228,118	6,695	154,993	6,772
Proved developed reserves						
Balance, beginning of year	164,787	5,685	124,451	5,653	139,137	5,915
Balance, end of year	213,175	5,764	164,787	5,685	124,451	5,653

(a) Excludes volumes produced and delivered with respect to the Production Payment sold in February 2001 as discussed in Note 1.

(b) The Company sold a Production Payment in 2001 as discussed in Note 1. The approximate 38.3 Bcf of natural gas and 797,000 barrels of oil Production Payment was reflected as sales of reserves in place in 2001. In 2002, the Company sold certain non-core properties.

Approximately 24% of the Company's reserves were classified as proved undeveloped. Furthermore, approximately 15% of the Company's proved developed reserves are classified as proved not producing. These reserves relate to zones that are either behind pipe or that have been completed but not yet produced, or zones that have been produced in the past but are not currently producing due to mechanical reasons. These reserves may be regarded as less certain than producing reserves because they are frequently based on volumetric calculations rather than performance data.

15. Subsequent Event

On February 22, 2005, the Company entered into a purchase and sale agreement ("Purchase Agreement") providing for the acquisition by the Company of a package of oil and gas properties and related assets ("Assets") located primarily in the Company's North Louisiana-East Texas core operating area. Upon closing of the Purchase Agreement, the Company shall be entitled to all of the rights of ownership (including, without limitation, the right to all production, proceeds of production, and other proceeds) and will be responsible for all operating expenses and liabilities, attributable to the Assets for the period of time from and after January 1, 2005.

The purchase price for the Assets will be approximately $94.7 million, subject to adjustment. The Company expects to initially finance the purchase of the Assets with cash on hand and borrowings under its bank credit facility.

The transactions contemplated by the Purchase Agreement are expected to close on April 13, 2005 or such other date as is agreed upon by the seller and the Company, subject to the satisfaction of customary closing conditions and the right of either the seller or the Company to terminate the Purchase Agreement in certain circumstances, including the right to terminate in the event the sum of certain title and environmental defects exceeds specified thresholds. The Purchase Agreement may be terminated at any time prior to closing for the following reasons, among others: (a) by seller, if its closing conditions have not been satisfied on or before closing; (b) by the Company, if its closing conditions have not been satisfied on or before closing and such conditions have not been cured by seller within ten days of written notice thereof; and (c) by seller or the Company if closing does not occur on or before April 23, 2005.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Evaluation of disclosure controls and procedures. Based on their evaluation of our disclosure controls and procedures as of the end of the period covered by this report, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures are effective in ensuring that the information required to be disclosed by us (including our consolidated subsidiaries) in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms.

Management's annual report on internal control over financial reporting. Management's report on internal control over financial reporting and the attestation report of our independent registered public accounting firm are included under "Financial Statements and Supplementary Data," and such reports are incorporated herein by reference.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

On March 2, 2005, the Board of Directors of KCS approved the following actions of the Compensation Committee (the "Compensation Committee") of the Board of Directors with regard to the compensation of the executive officers who were named in the Summary Compensation Table of KCS' 2004 Proxy Statement and who are expected to be named in the Summary Compensation Table of KCS' 2005 Proxy Statement:

2005 Base Salary Increases. The Compensation Committee approved increases to the base salaries of the named executive officers, effective February 1, 2005. The base salaries of the named executive officers for 2005 are as follows: James W. Christmas, Chairman and Chief Executive Officer ($400,000, a 4.1% increase over 2004); William N. Hahne, President and Chief Operating Officer ($312,000, a 3.8% increase over 2004); Harry Lee Stout, Senior Vice President, Marketing and Risk Management ($216,000, a 2.7% increase over 2004); Joseph T. Leary, Vice President and Chief Financial Officer ($190,000, an 8.6% increase over 2004); and Frederick Dwyer, Vice President, Controller and Secretary ($145,000, a 3.6% increase over 2004).

Annual Incentive Compensation Earned in 2004. The Compensation Committee approved annual cash bonus awards earned during 2004 and to be paid on March 18, 2005 for the named executive officers. The amounts of the bonus awards are as follows: Mr. Christmas ($219,900); Mr. Hahne ($156,200); Mr. Stout ($65,600); Mr. Leary ($65,600); and Mr. Dwyer ($60,000). In addition to the aforementioned bonus award, Mr. Dwyer was paid $30,000 in February 2005 in connection with a retention agreement.

Other Compensation Information. KCS will provide additional information regarding the compensation paid to the named executive officers for the 2004 fiscal year in KCS' proxy statement for the 2005 Annual Meeting of Shareholders, which is expected to be filed with the SEC in April 2005.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

Information concerning our executive officers and directors is set forth in the sections entitled "Election of Directors" and "Executive Officers" of our Proxy Statement for the 2005 Annual Meeting of Stockholders, which sections are incorporated in this annual report on Form 10-K by reference. Information concerning compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth in the section entitled "Section 16(a) Beneficial Ownership Reporting Compliance" of our Proxy Statement for the 2005

Annual Meeting of Stockholders, which section is incorporated in this annual report on Form 10-K by reference.

Information concerning our audit committee and our audit committee financial expert is set forth in the section entitled "Information Concerning the Board of Directors and Certain Committees of the Board of Directors" in our Proxy Statement for the 2005 Annual Meeting of Stockholders, which section is incorporated in this annual report on Form 10-K by reference.

We have adopted a Code of Ethics applicable to our principal executive officer, principal financial officer and principal accounting officer. The Code of Ethics applicable to our principal executive officer, principal financial officer and principal accounting officer was filed as Exhibit 14.1 to our annual report on Form 10-K for the year ended December 31, 2003 and is available on our Internet website at *www.kcsenergy.com.* If we amend the Code of Ethics or grant a waiver, including an implicit waiver, from the Code of Ethics, we intend to disclose the information on our Internet website within four business days of such amendment or waiver.

Certification

As required by New York Stock Exchange ("NYSE") listing standards, James W. Christmas, our Chief Executive Officer, certified on August 3, 2004 that he was not aware of any violation by KCS of NYSE corporate governance listing standards. The certifications required by Section 302 of the Sarbanes-Oxley Act were filed with the Securities and Exchange Commission on March 15, 2005 as exhibits 31.1 and 31.2 to KCS' Annual Report on Form 10-K.

Item 11. ***Executive Compensation.***

Information for this item is set forth in the sections entitled "Executive Compensation," "Compensation Committee Interlocks and Insider Participation," "Employment Agreements, Change in Control Agreements and Retention Agreements," and "Compensation of Directors" in our Proxy Statement for the 2005 Annual Meeting of Stockholders, which sections are incorporated in this annual report on Form 10-K by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

Information for this item is set forth in the section entitled "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement for the 2005 Annual Meeting of Stockholders, which section is incorporated in this annual report on Form 10-K by reference.

Information concerning securities authorized for issuance under our equity compensation plans is set forth in Item 5 of this Form 10-K and is incorporated in Item 12 of this annual report on Form 10-K by reference.

Item 13. ***Certain Relationships and Related Transactions.***

Information for this item is set forth in the section entitled "Certain Relationships and Related Transactions" in our Proxy Statement for the 2005 Annual Meeting of Stockholders, which section is incorporated in this annual report on Form 10-K by reference.

Item 14. ***Principle Accounting Fees and Services.***

Information for this item is set forth in the section entitled "Independent Registered Public Accounting Firm" in our Proxy Statement for the 2005 Annual Meeting of Stockholders, which section is incorporated in this annual report on Form 10-K by reference.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a) *List of Documents Filed as Part of the Report:*

(1) *Financial Statements.* The following consolidated financial statements and the related Report of Independent Registered Accounting Firm are presented in Part II, Item 8 of this annual report on Form 10-K on the pages indicated below.

(2) *Financial Statement Schedules.* Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in our consolidated financial statements and related notes.

(3) *Exhibits.*

Exhibit No.	Description
2.1	Order of the United States Bankruptcy Court for the District of Delaware confirming the KCS Energy, Inc. Plan of Reorganization (incorporated by reference to Exhibit 2 to Form 8-K (File No. 001-13781) filed with the SEC on March 1, 2001).
3.1	Restated Certificate of Incorporation of KCS Energy, Inc. (incorporated by reference to Exhibit (3)i to Form 10-K (File No. 001-13781) filed with the SEC on April 2, 2001).
3.2	Restated By-Laws of KCS Energy, Inc. (incorporated by reference to Exhibit (3)iii to Form 10-K (File No. 001-13781) filed with the SEC on April 2, 2001).
3.3	Amendments to Restated By-Laws of KCS Energy, Inc. effective April 22, 2003 (incorporated by reference to Exhibit 3.1 to Form 10-Q (File No. 001-13781) filed with the SEC on August 14, 2003).
4.1	Form of Common Stock Certificate, $0.01 Par Value (incorporated by reference to Exhibit 5 to registration statement on Form 8-A (No. 001-11698) filed with the SEC on January 27, 1993).
4.2	Indenture, dated as of April 1, 2004, among KCS Energy, Inc., certain of its subsidiaries and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Form 10-Q (File No. 001-13781) filed with the SEC on May 10, 2004).
4.3	Form of 7⅛% Senior Note due 2012 (included in Exhibit 4.2).
10.1	1988 KCS Group, Inc. Employee Stock Purchase Program (incorporated by reference to Exhibit 4.1 to registration statement on Form S-8 (No. 33-24147) filed with the SEC on September 1, 1988).*
10.2	Amendments to 1988 KCS Energy, Inc. Employee Stock Purchase Program (incorporated by reference to Exhibit 4.2 to registration statement on Form S-8 (No. 33-63982) filed with the SEC on June 8, 1993).*
10.3	KCS Energy, Inc. 2001 Employee and Directors Stock Plan (incorporated by reference to Exhibit (10)iii to Form 10-K (File No. 001-13781) filed with the SEC on April 2, 2001).*

Exhibit No.	Description
10.4	KCS Energy, Inc. Savings and Investment Plan and related Adoption Agreement and Summary Plan Description (incorporated by reference to Exhibit 10.4 to Form 10-K (File No. 001-13781) filed with SEC on March 15, 2004).*
10.5	Purchase and Sale Agreement between KCS Resources, Inc., KCS Energy Services, Inc., KCS Michigan Resources, Inc. and KCS Medallion Resources, Inc., as sellers, and Star VPP, LP, as Buyer, dated as of February 14, 2001 (incorporated by reference to Exhibit (10)vi to Form 10-K (File No. 001-13781) filed with the SEC on April 2, 2001).
10.6	Second Amended and Restated Credit Agreement, dated as of November 18, 2003, by and among KCS Energy, Inc., the lenders from time to time party thereto, Bank of Montreal, as Agent and Collateral Agent, and BNP Paribas, as Documentation Agent (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 001-13781) filed with the SEC on November 19, 2003).
10.7	First Amendment to Second Amended and Restated Credit Agreement, effective as of February 26, 2004, by and among KCS Energy, Inc., the lenders from time to time party thereto, Bank of Montreal, as Agent and Collateral Agent, and BNP Paribas, as Documentation Agent (incorporated by reference to Exhibit 10.7 to Form 10-K (File No. 001-13781) filed with the SEC on March 15, 2004).
10.8	Second Amendment to Second Amended and Restated Credit Agreement, effective as of March 17, 2004, by and among KCS Energy, Inc., the lenders from time to time party thereto, Bank of Montreal, as Agent and Collateral Agent, and BNP Paribas, as Documentation Agent, and Bank One, NA, as Syndication Agent.†
10.9	Third Amendment to Second Amended and Restated Credit Agreement, dated and effective as of December 1, 2004, by and among KCS Energy, Inc., the lenders party thereto, Bank of Montreal, as Agent and Collateral Agent, BNP Paribas, as Documentation Agent, and JPMorgan Chase Bank, N.A., as Syndication Agent (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 001-13781) filed with the SEC on December 7, 2004).
10.10	Registration Rights Agreement, dated April 1, 2004, by and among KCS Energy, Inc., KCS Resources, Inc., Medallion California Properties Company, KCS Energy Services, Inc., Proliq, Inc., Credit Suisse First Boston LLC, Merill Lynch, Pierce, Fenner & Smith, Incorporated, Jefferies & Company, Inc., Harris Nesbitt Corp., Banc One Capital Markets, Inc., and BNP Paribas Securities Corp. (incorporated by reference to Exhibit 10.2 to Form 10-Q (File No. 001-13781) filed with the SEC on May 10, 2004).
10.11	Employment Agreement between KCS Energy, Inc. and James W. Christmas (incorporated by reference to Exhibit (10)vii to Form 10-K (File No. 001-13781) filed with the SEC on April 1, 2002).*
10.12	Amendment No. 1 to Employment Agreement, dated August 1, 2004, between KCS Energy, Inc. and James W. Christmas (incorporated by reference to Exhibit 10.1 to Form 10-Q (File No. 001-13781) filed with the SEC on November 9, 2004).*
10.13	Employment Agreement between KCS Energy, Inc. and William N. Hahne (incorporated by reference to Exhibit (10)viii to Form 10-K (File No. 001-13781) filed with the SEC on April 1, 2002).*
10.14	Amendment No. 1 to Employment Agreement, dated August 1, 2004, between KCS Energy, Inc. and William N. Hahne (incorporated by reference to Exhibit 10.2 to Form 10-Q (File No. 001-13781) filed with the SEC on November 9, 2004).*
10.15	Employment Agreement between KCS Energy, Inc. and Harry Lee Stout (incorporated by reference to Exhibit (10)ix to Form 10-K (File No. 001-13781) filed with the SEC on April 1, 2002).*
10.16	Amendment No. 1 to Employment Agreement, dated August 1, 2004, between KCS Energy, Inc. and Harry Lee Stout (incorporated by reference to Exhibit 10.3 to Form 10-Q (File No. 001-13781) filed with the SEC on November 9, 2004).*
10.17	Change in Control Agreement dated May 27, 2003 between KCS Energy, Inc. and Joseph T. Leary (incorporated by reference to Exhibit 10.2 to Form 10-Q (File No. 001-13781) filed with the SEC on August 14, 2003).*

Exhibit No.	Description
10.18	Amendment No. 1 to Change in Control Agreement, dated August 1, 2004, between KCS Energy, Inc. and Joseph T. Leary (incorporated by reference to Exhibit 10.4 to Form 10-Q (File No. 001-13781) filed with the SEC on November 9, 2004).*
10.19	Change in Control Agreement dated May 1, 2003 between KCS Energy, Inc. and Frederick Dwyer (incorporated by reference to Exhibit 10.3 to Form 10-Q (File No. 001-13781) filed with the SEC on August 14, 2003).*
10.20	Amendment No. 1 to Change in Control Agreement, dated August 1, 2004, between KCS Energy, Inc. and Frederick Dwyer (incorporated by reference to Exhibit 10.5 to Form 10-Q (File No. 001-13781) filed with the SEC on November 9, 2004).*
10.21	Form of Supplemental Stock Option Agreement (incorporated by reference to Exhibit 10.6 to Form 10-Q (File No. 001-13781) filed with the SEC on November 9, 2004).*
10.22	Form of Directors Supplemental Stock Option Agreement (incorporated by reference to Exhibit 10.7 to Form 10-Q (File No. 001-13781) filed with the SEC on November 9, 2004).*
10.23	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.8 to Form 10-Q (File No. 001-13781) filed with the SEC on November 9, 2004).*
10.24	Form of Restricted Stock Award Agreement (with accelerated vesting provision) (incorporated by reference to Exhibit 10.9 to Form 10-Q (File No. 001-13781) filed with the SEC on November 9, 2004).*
12.1	Statement Regarding Computation of Ratios.†
14.1	Code of Ethics (incorporated by reference to Exhibit 14.1 to Form 10-K (File No. 001-13781) filed with the SEC on March 15, 2004).
21.1	Subsidiaries of KCS Energy, Inc.†
23.1	Consent of Netherland, Sewell and Associates, Inc.†
23.2	Consent of Ernst & Young LLP.†
31.1	Rule 13a-14(a)/15d-14(a) Certification of James W. Christmas, Chief Executive Officer.†
31.2	Rule 13a-14(a)/15d-14(a) Certification of Joseph T. Leary, Chief Financial Officer.†
32.1	Section 1350 Certification of James W. Christmas, Chief Executive Officer.†
32.2	Section 1350 Certification of Joseph T. Leary, Chief Financial Officer.†

* Management contract or compensatory plan or arrangement.

† Filed herewith.

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.

KCS ENERGY, INC.

By: /s/ FREDERICK DWYER

Frederick Dwyer
Vice President, Controller and Secretary

Date: March 15, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ JAMES W. CHRISTMAS James W. Christmas	Chairman, Chief Executive Officer and Director (Principal Executive Officer)	March 15, 2005
/s/ WILLIAM N. HAHNE William N. Hahne	President, Chief Operating Officer and Director	March 15, 2005
/s/ JOSEPH T. LEARY Joseph T. Leary	Vice President and Chief Financial Officer (Principal Financial Officer)	March 15, 2005
/s/ FREDERICK DWYER Frederick Dwyer	Vice President, Controller and Secretary (Principal Accounting Officer)	March 15, 2005
/s/ G. STANTON GEARY G. Stanton Geary	Director	March 15, 2005
/s/ ROBERT G. RAYNOLDS Robert G. Raynolds	Director	March 15, 2005
/s/ JOEL D. SIEGEL Joel D. Siegel	Director	March 15, 2005
/s/ CHRISTOPHER A. VIGGIANO Christopher A. Viggiano	Director	March 15, 2005

Corporate Directory

Corporate Officers

[illegible] W. Christmas
Chairman and
Chief Executive Officer

[illegible] N. Hahne
President and
Chief Operating Officer

[illegible]
Senior Vice President,
Marketing and
Risk Management

[illegible]
Vice President and
Chief Financial Officer

[illegible] Dwyer
Vice President,
Controller and Secretary

[illegible]
Vice President,
Human Resources

[illegible] Wesley VanNatta
Vice President,
Reserves & Acquisitions

Principal Operating Officers

David E. Chandler
Vice President,
Operations Controller

D.R. Deffenbaugh
Vice President,
Mid-Continent Land

[illegible] Ross, Jr.
Senior Vice President,
Gulf Coast Division

H. Weldon Holcombe
Vice President,
Mid-Continent
Engineering & Operations

[illegible] W. Latch
Vice President,
Gulf Coast
Engineering & Operations

[illegible]
Vice President,
Mid-Continent Exploration

Corporate Office

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Houston, TX 77056
(713) 877-8006
FAX (713) 877-1372

Principal Operating Offices

Gulf Coast Operations
5555 San Felipe
Suite 1200
Houston, TX 77056
(713) 877-8006
FAX (713) 622-7671

Mid-Continent Operations
7130 S. Lewis Avenue
Suite 700
Tulsa, OK 74136
(918) 488-8283
FAX (918) 488-8182

Website

Visit our website at
www.kcsenergy.com

Stockholder Information

Common Stock

The common stock of KCS Energy, Inc. is traded on the New York Stock Exchange under the symbol "KCS."

Listed below are the high and low sales prices per share of common stock for the periods indicated.

Registrar and Transfer Agent

Registrar and Transfer Company
10 Commerce Drive
Cranford, NJ 07016
[illegible]

2004		Jan. - Mar.	Apr. - June	July - Sept.	Oct. - Dec.
Market Price	High	$11.50	$13.60	$14.99	$15.09
	Low	$08.68	$10.50	$11.26	$12.29

2003		Jan. - Mar.	Apr. - June	July - Sept.	Oct. - Dec.
Market Price	High	$3.06	$5.70	$7.64	$10.84
	Low	$1.76	$2.31	$4.71	$06.77

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