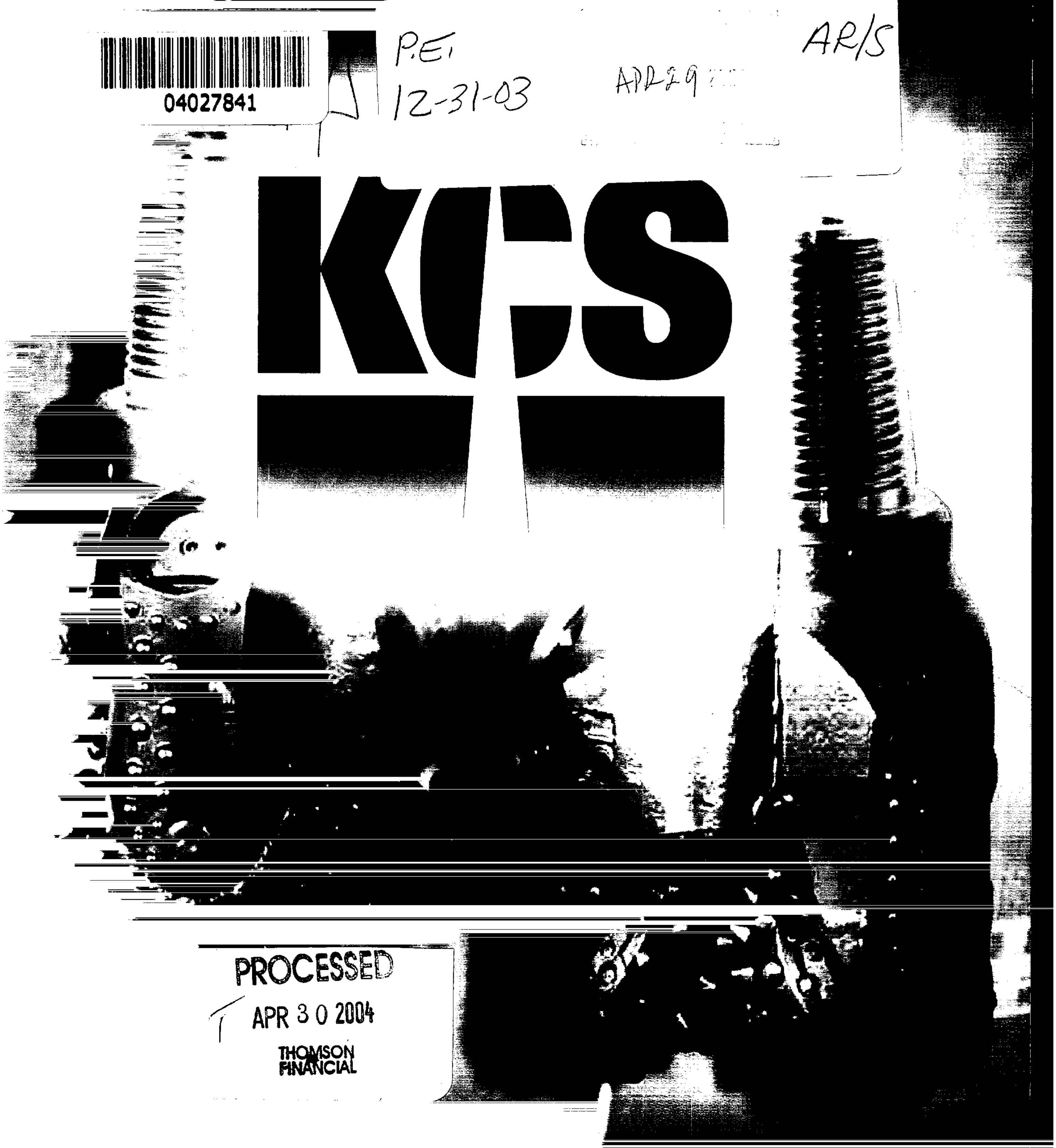
KCS Energy, Inc. Annual Report 2003

KCS



Growing Value via the Drill Bit

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.

2003 Highlights

★ Drilled 78 wells with a 92% success ratio

★ Increased production by 24% gross or 43% net

★ Increased proved reserves by 37% to 268 Bcfe

★ Increased our drilling prospect inventory

★ Generated record net income of $68.6 million

★ Reduced debt for the 5th consecutive year

★ Secured a $100 million revolving credit facility

★ Raised $52 million of new equity

★ Number 6 gainer on NYSE – up 517%

To Our Shareholders:

I am pleased to report that the year 2003 was one of the most successful in our history. We focused on a low-risk drilling program in our core areas of operation where we experienced significant increases in our oil and gas reserves and production. The success of our drilling program, coupled with strong commodity prices and continued cost control efforts resulted in record net income, significant quarter to quarter growth in production, a 37% increase in our proved reserves, continued debt reduction and solid stock price performance. In fact, our stock was up over 500% in 2003, making KCS the number 6 gainer on the New York Stock Exchange for the year.

We started the year with several key goals; to repay the remaining senior notes at maturity in January 2003, to expand our drilling efforts to increase our reserves and production, to enhance our financial flexibility and to continue to reduce debt. We accomplished these goals and much more. The result of these efforts is not only what can be seen in our 2003 operating and financial performance, but also a solid platform of drilling locations in existing properties and numerous newly acquired prospects which should provide continuing growth.

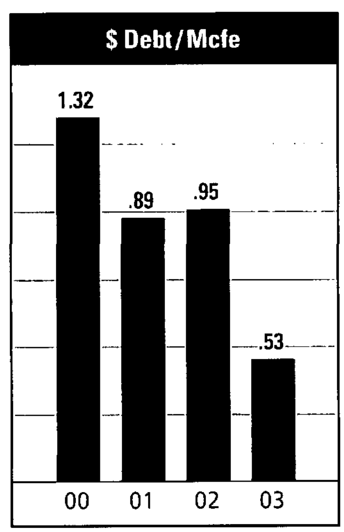
"Over the last 3 years, we have reduced debt $210 million while increasing our oil and gas reserves."

James W. Christmas
Chairman and
Chief Executive Officer

Improved Financial Position

We also continued to strengthen our financial position and increase our financial flexibility. During the fourth quarter we finalized a new $100 million revolving credit facility with lower borrowing costs and raised $52 million of new equity. These additional funds not only make us a much stronger company financially, but also enable us to accelerate the drilling of the many locations we currently have in inventory. We ended the year with stockholders' equity of $98 million, compared to a deficit of $43 million at the beginning of the year.

We began the year with a $45 million capital expenditure budget. However, based on increased cash flow resulting from



To Our Shareholders:

the successful drilling program and strong commodity prices we were able to increase it several times during the year, ultimately investing $88 million in our oil and gas properties.

In addition, we reduced debt for the fifth straight year, to $142 million or $.53 per Mcfe at year-end. These actions, coupled with lower interest rates, mean significantly lower interest expense in 2004.

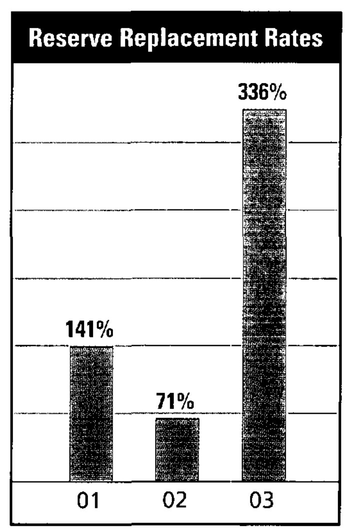
"Our strategy is simple – to focus on low-risk drilling in our core operating areas and commit 12-15% of our budget to higher-potential exploration prospects."

Financial Results

Revenues grew 39% to $165 million. Operating income increased 138% to $70 million. Net income was a record $68.6 million compared to a loss last year of $10.1 million. This increase in net income includes the impact of a reduction in the valuation allowance against our deferred tax assets this year as a result of the significant improvement in the Company's earnings and outlook. I encourage you to read Management's Discussion and Analysis on page 23 of the Form 10-K report included as part of this annual report for more information about our financial results.

Strategy

Our strategy going forward is simple, and really a continuation of what we executed in 2003. We plan to focus on low-risk development and exploitation drilling in our core operating areas, committing about 12-15% of our capital expenditure budget to moderate-risk, higher-potential exploration prospects in the on-shore Gulf Coast area. We intend to stay focused on natural gas, which we believe offers more upside potential. 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 expected to continue to be strong, we will continue 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 protect 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.

Summary and Outlook

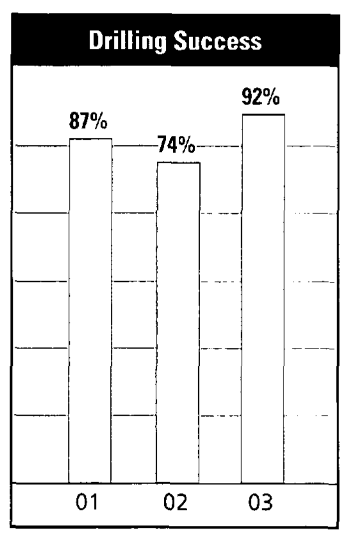
Over the last three years, we have reduced our debt 60%, or by $210 million, while still increasing our oil and gas reserves slightly. Looking ahead, we are poised to continue growing our reserves and production while further reducing our debt per Mcfe. Today KCS is in a much stronger financial position than it has been for quite some time and has significant financial flexibility to capitalize on growth opportunities.

Looking forward, we have initially budgeted $105 million for our 2004 capital expenditure program and plan to drill more than 100 wells. Based on the average finding and development cost over the last three years, less than half of this is required to replace our production outlook for 2004, which implies another solid year of expected growth in our oil and gas reserves. We believe that this program can be funded primarily through cash flow. Our focus will be on adding reserves and production in our core areas, and further reducing our costs per Mcfe in order to enhance profitability. After successfully completing a lengthy and difficult turnaround, it was gratifying to see the growth in reserves and production from our 2003 program. We look forward to increasing our level of drilling in 2004 and continuing the growth that began in 2003. With a talented, dedicated and motivated group of employees, we are truly excited about the future.

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

James W. Christmas
Chairman and Chief Executive Officer
March 31, 2004

"Drilling locations in existing properties and newly acquired prospects should provide continued growth."

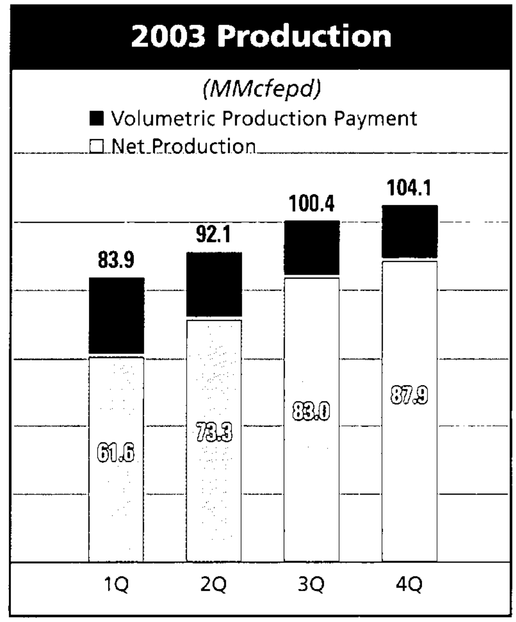


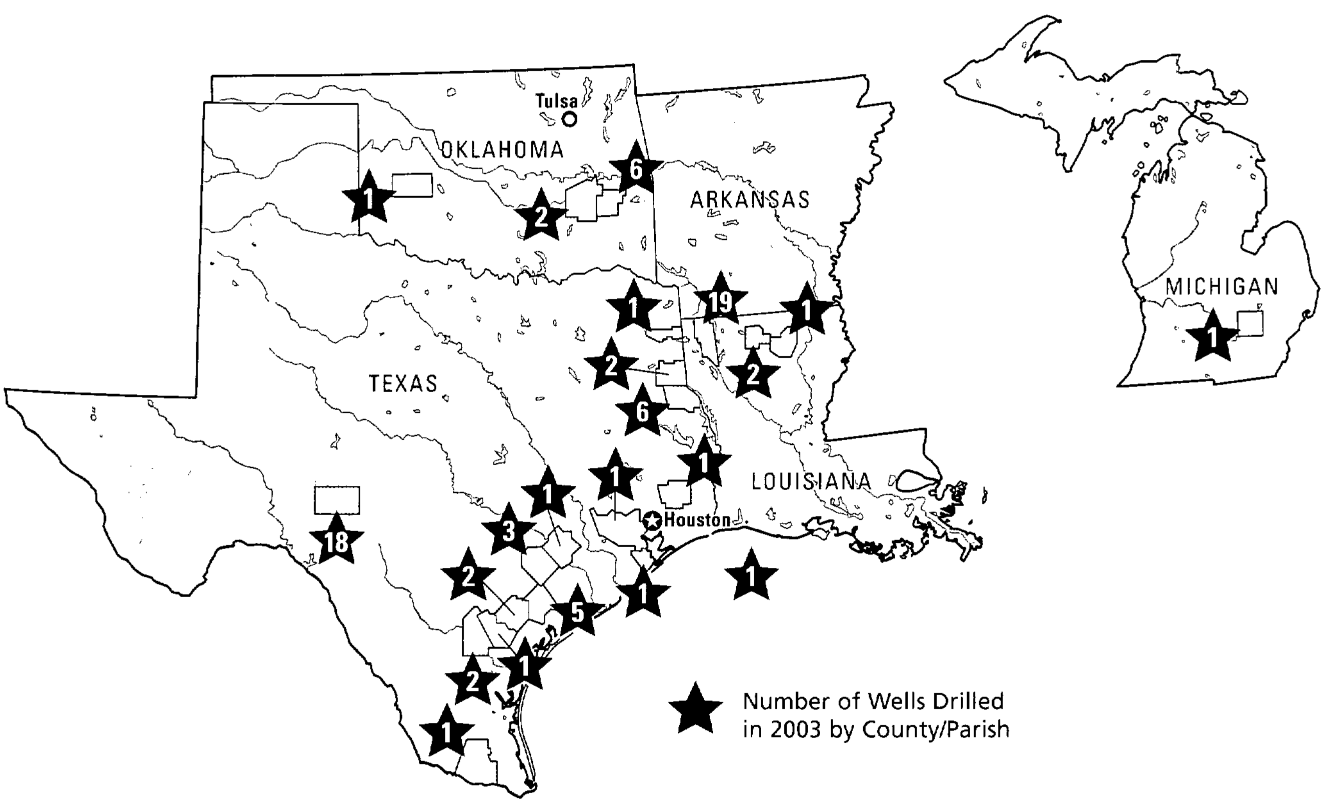
Operations Review

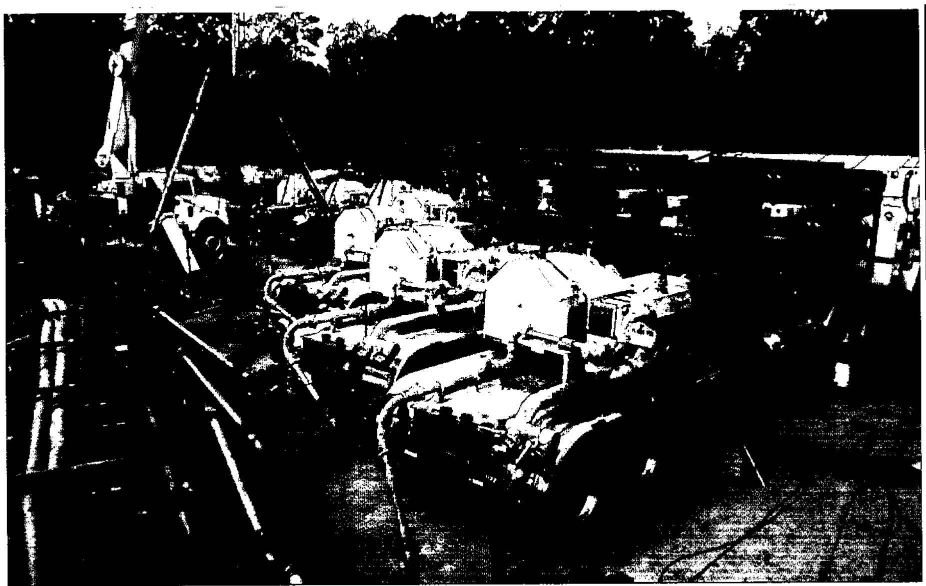
Drilling Onshore Gas Wells in the United States

During 2003, with our dramatically improved financial position and solid oil and gas prices, we ramped up drilling activity. We drilled 78 wells in 2003 compared to 53 wells in 2002, increasing our net production, cash flow and reserves, and importantly, confirming the potential of our future drilling inventory.

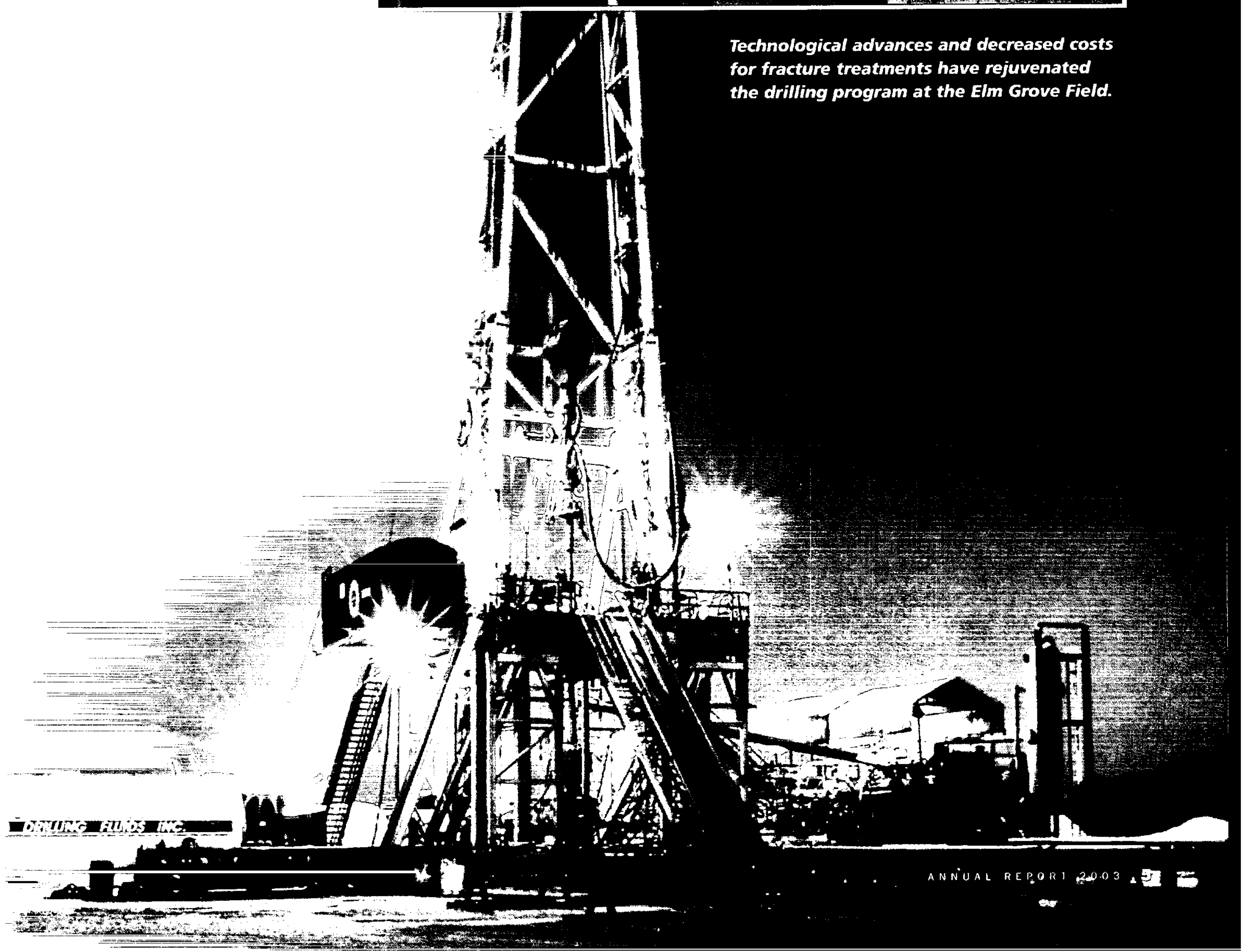
We are a company that is focused on drilling and producing thick, tight gas reservoirs in onshore United States fields. Our properties are primarily located in the Mid-Continent and onshore Gulf Coast regions. We also have interests in producing properties in Michigan, California and Wyoming. As of December 31, 2003, our oil and natural gas properties were estimated to have net proved reserves of 268 Bcfe. Approximately 85% of our net proved reserve base was natural gas and approximately 74% was classified as proved developed. We operate approximately 78% of the reserve base.







Technological advances and decreased costs for fracture treatments have rejuvenated the drilling program at the Elm Grove Field.



Operations Review

Over the last several years, our professional staff of geologists, engineers and landmen has amassed a significant inventory of drilling opportunities within existing KCS fields and in newly acquired prospect areas. Our landmen secured key acreage, our drillers cleared new locations, moved in drilling rigs and drilled to the targets identified by the geologists and the engineering and production staff designed fracture treatments to stimulate the gas filled rock and installed surface production equipment and flowlines to increase production rates.

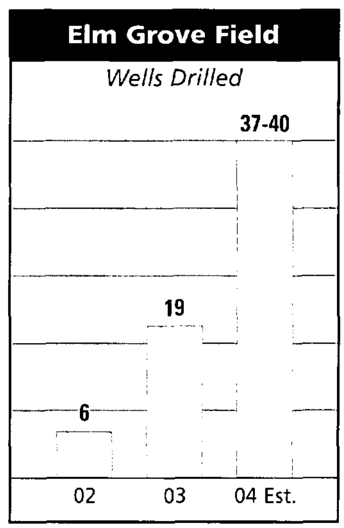
Our 2003 drilling program yielded exceptional results, increasing the Company's production by 24% from the first quarter to the fourth quarter of 2003 (or by 43% considering volumes which contribute to cash flow, after subtracting production payment obligations) and growing reserves by 37% from 196 Bcfe to 268 Bcfe. The reserve growth was based on the addition of 93.8 Bcfe of reserves, having spent $88.1 million with an annual finding and development cost of $.94 per Mcfe. With net production of approximately 28 Bcfe, the reserve adds replaced production by 336%.

Our staff focused our drilling efforts on both existing fields such as Elm Grove and Sawyer Canyon as well as new areas including Talihina, Joaquin and south Texas fields.

"We focus on drilling and producing thick, tight gas reservoirs in onshore United States fields."

Elm Grove Field, North Louisiana

Contributing about 20% of our production and 30% of our reserves, this field, which produces from the Cotton Valley and Hosston formations, is one of our primary areas of activity and growth. KCS drilled 6 wells in 2002. In 2003 we drilled 19 wells and re-completed another 15 wells. The impact of the work was significant, increasing gross production rates on the operated leases from 6 MMcfpd in 2002 to approximately 30 MMcfpd by year-end 2003. In 2004 we anticipate drilling 37-40 wells, keeping two drilling rigs busy for the entire year.

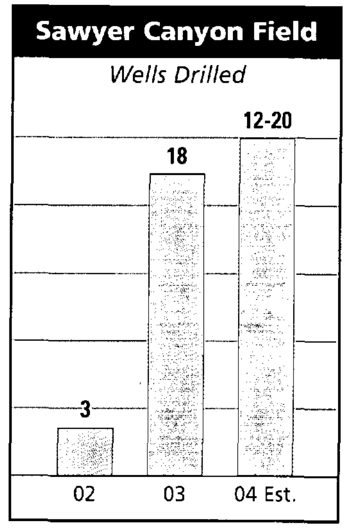


Right: Kelly Byram, Gary Leonard and John Walsh discuss North Louisiana acreage acquisition.

Operations Review

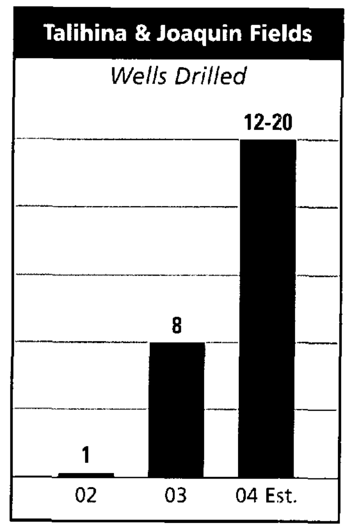
Sawyer Canyon Field, West Texas

Our second largest field, which contributed approximately 12% of our production in 2003, produces shallow Canyon sandstone zones. We drilled 18 wells in 2003 and plan to drill 12-20 wells in 2004, which provide a solid base of production replacement at low cost and risk.



Other Mid-Continent Fields

In late 2002 and early 2003 we began development of two new fields in the Mid-Continent division – The Talihina Field in the Arkoma basin of Oklahoma and the Joaquin Field in east Texas. Drilling programs in these two areas yielded strong initial production rates and with approximately 11,000 gross acres at Talihina and 5,000 gross acres at Joaquin, we expect to continue infill and extension drilling for a number of years to come.



South Texas Activity

Eighteen wells were drilled in south Texas in 2003, including two significant exploration discoveries – the East Marshall and Five Mile Creek prospects. Two follow up successes have been placed on production at East Marshall and 2-3 additional development wells are budgeted for the field in 2004. We've slated 10-12 exploration wells to be drilled in south Texas

Right: John Nikonchik and Bryan Richards discuss South Texas Wilcox drilling potential.

Left: KCS Operating Officers responsible for the Company's drilling programs: (Left to right) Brad Magill, Rick Deffenbaugh, Wes VanNatta, Weldon Holcombe, Cliff Foss and David Chandler.


Pogo

Operations Review

during 2004, with all targeting either Wilcox, Frio or Vicksburg formations on trend with our producing fields. We also plan to drill 12-13 development wells in this region.

Our initial 2004 budget of $105 million anticipates the drilling of over 100 new wells. With an inventory of approximately 130 proved undeveloped drilling locations and over 450 probable and possible locations, we have a multi-year inventory of wells to drill. We are also actively pursuing new acreage positions on trend with our current fields to continually grow the Company. We believe one of the key strengths of KCS is the substantial number of identified drilling prospects, which should provide growth for years to come.

In 2004, our plan is simply to do more of the same:

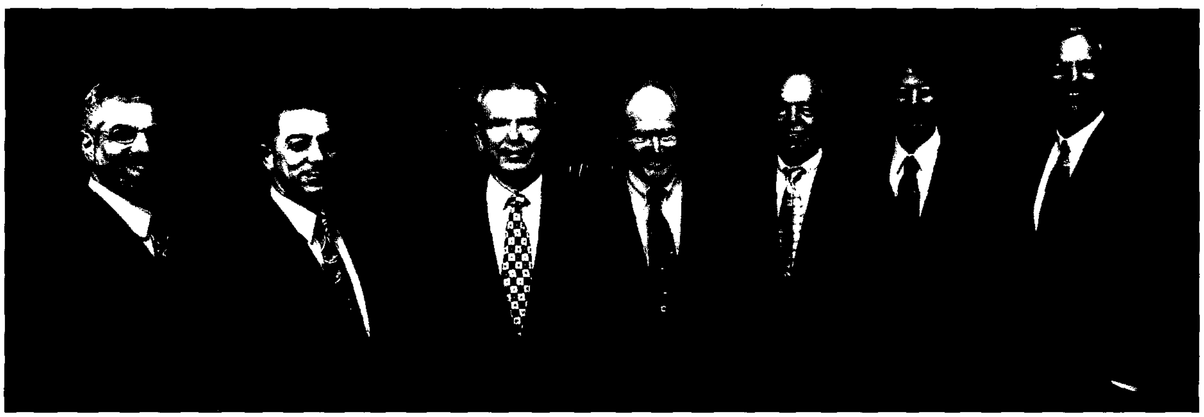
- Focus on natural gas;
- Continue drilling in our core operating areas;
- Exploit our large inventory of drilling prospects; and
- Grow production and reserves via the drill bit to maximize shareholder value.

"In 2004 we expect to continue drilling in areas that have proven successful, to increase production and reserves and to increase shareholder value."

Right: Paul Braun, Mike Stolte and Jim Travillo confer on the completion of a Gulf Coast wildcat.

Left: KCS has a staff of 128 technical, support and field personnel which find and produce oil and gas wells.

Directors & Officers



Board of Directors

Left to right:

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

CHRISTOPHER A. VIGGIANO[1,2]
President and Chairman,
O'Bryan Glass Corporation
Specialty Glass Manufacturer

JAMES W. CHRISTMAS[3]
Chairman and
Chief Executive Officer,
KCS Energy, Inc.

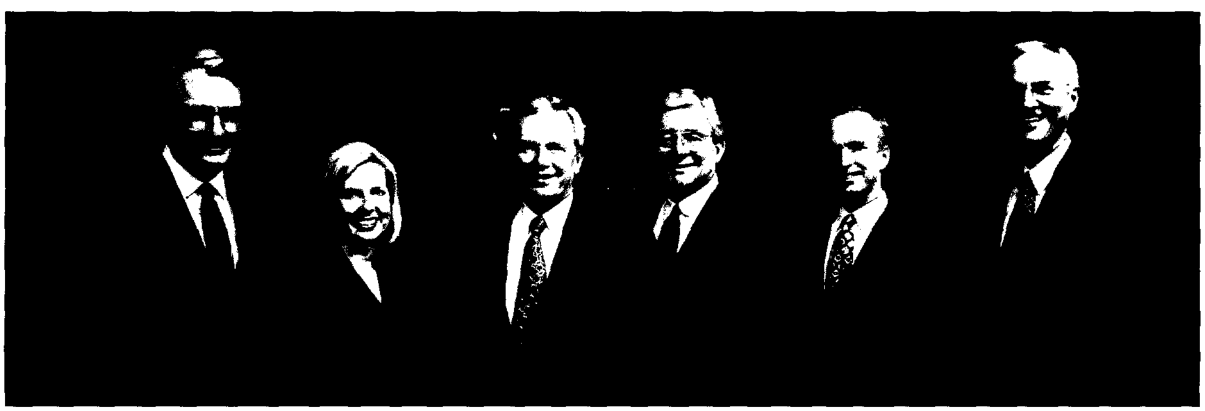
G. STANTON GEARY[2]
Proprietor,
Gemini Associates
Venture Capital Consulting Firm

JAMES L. BOWLES[1]
Past President of
Phillips Americas Division of
Phillips Petroleum Company

ROBERT G. RAYNOLDS, PHD[2,3,4]
Independent Consulting
Geologist

WILLIAM N. HAHNE
President and
Chief Operating Officer
KCS Energy, Inc.

[1] *Member Compensation Committee*
[2] *Member Audit Committee*
[3] *Member Executive Committee*
[4] *Lead Outside Director*



Corporate Officers

Left to right:

JOSEPH T. LEARY
Vice President and
Chief Financial Officer

JULIE A. LONG
Vice President,
Human Resources

JAMES W. CHRISTMAS
Chairman and
Chief Executive Officer

HARRY LEE STOUT
Senior Vice President,
Marketing and
Risk Management

FREDERICK DWYER
Vice President,
Controller and Secretary

WILLIAM N. HAHNE
President and
Chief Operating Officer

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, 2003

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)

Delaware	**22-2889587**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5555 San Felipe Road, 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
8 7/8% Senior Subordinated Notes due 2006	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 34,788,616 shares of the registrant's common stock, par value $0.01 per share, held by non-affiliates of the registrant at the $5.39 closing price on June 30, 2003 (the last business day of the registrant's most recently completed second fiscal quarter) was $187,510,640.

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 5, 2004: 48,736,596.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement for the Annual Meeting of Stockholders to be held on May 27, 2004 are incorporated by reference into Part III of this annual report on Form 10-K.

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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 (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 because Standardized Measure includes the 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 and Wyoming. As of December 31, 2003, our oil and natural gas properties were estimated to have net proved reserves of 268.3 Bcfe with a PV-10 value, net of asset retirement obligations, of approximately $630 million. Approximately 85% of our net proved reserve base was natural gas and approximately 74% was classified as proved developed. We operate approximately 78% 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, 2003.

	Estimated Proved Reserves			
	Natural Gas (MMcf)	Oil (Mbbls)	Total (MMcfe)	Percent of Reserves
Mid-Continent Region	153,076	532	156,268	58%
Gulf Coast Region	53,480	1,488	62,408	23%
Other Properties(1)	21,562	4,675	49,612	19%
Total Company	228,118	6,695	268,288	100%

(1) Michigan, California and Wyoming.

In 2003, we produced an average of 95.2 MMcfe per day. 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 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 formed 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, 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.

2003 Highlights

The year ended December 31, 2003 was one of the most successful in our history. We focused on a low-risk drilling program in our core areas of operation where we experienced significant increases in oil and natural gas reserves and production. We drilled 78 wells during 2003, of which 72 were completed, resulting in a 92% success rate. Production from our properties averaged 77.2 MMcf per day of natural gas and 3,002 barrels of oil and natural gas liquids per day, or 95.2 MMcfe per day for 2003. We increased production 24%, from an average of 83.9 MMcfe per day during the first quarter to an average of 104.1 MMcfe per day during the fourth quarter. Oil and natural gas reserves increased during 2003 to 268.3 Bcfe, which includes reserve additions of 93.8 Bcfe, replacing 336% of our 2003 net production. Including positive reserve revisions of 10.5 Bcfe, our overall reserve replacement rate was 373%.

We took several major steps during 2003 to further strengthen our financial condition, lower interest costs and provide increased financial flexibility. The balance of our outstanding Series A Convertible Preferred Stock was converted into shares of our common stock. This conversion simplified our overall capital structure and eliminated the 5% dividend obligation associated with the preferred stock. In the first quarter we paid off our maturing senior note obligations. In the fourth quarter, we amended and restated our bank credit facility, which increased our revolving credit capacity to $100 million and significantly reduced our borrowing costs. We also completed a public offering of 6.9 million shares of our common stock. We used a portion of the net proceeds of approximately $52 million to repay borrowings under our bank credit facility and to accelerate our drilling program in certain core areas. Our successful drilling program, along with strong oil and natural gas prices and proceeds from our public common stock offering, allowed us to reduce debt from $186.8 million, or $0.95 per Mcfe of reserves, at the beginning of the year to $142.0 million, or $0.53 per Mcfe of reserves, at the end of the year.

We believe that the steps taken during 2003, along with our multi-year drilling prospect inventory, position us to increase production and reserves in 2004 and beyond.

Competitive Strengths and Business Strategies

We intend to continue to increase production and reserves and further reduce debt per Mcfe to optimize stockholder value by executing the following strategies:

- *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 192 Bcfe to our reserves, of which 86% were through the drill bit. With our extensive inventory of drilling prospects, we believe that we are well-positioned to continue growing our reserves and production.

- *Focus on Natural Gas* — As of December 31, 2003, our proved reserves were 85% 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.

- *Exploit Our Large Inventory of Drilling Projects* — During the last four years, we have built a significant inventory of future drilling locations in targeted areas. We have identified approximately 130 proved undeveloped drilling locations and over 450 potential locations that create additional reserve growth opportunities. 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 78% of our proved oil and natural gas reserve base as of December 31, 2003. 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, 2003, we controlled the drilling operations on 60 of the 78 wells in which we participated.

- *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 23 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 $105 million on capital projects in 2004. 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 2003, we drilled 58 wells in this region with a success rate of 95%. We have a multi-year inventory of locations in the Mid-Continent region and plan to increase the level of drilling in our Elm Grove, Talihina and Joaquin fields and to continue the development program in our Sawyer Canyon Field in 2004.

- *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 working interests (WI) ranging from 91-100%. We also have a non-operated 33% WI interest in one section. In 2003, the field contributed about 20% of our net production. As of year-end, 2003, we had 77 Bcfe of proved reserves in this field that accounted for approximately 34% of our PV-10.

  We began a development program in late 2002 that included the drilling of six wells. In 2003, we worked over 15 wells and drilled 19 additional wells, all of which were successful. This workover and drilling activity increased gross operated production from 6 MMcfe per day in 2002 to approximately 30 MMcfe per day at December 31, 2003. In 2004, we plan to drill 37-40 proved undeveloped and step-out locations to continue growing production and reserves.

- *Sawyer Canyon Field* — Our second largest field, contributing approximately 12% of our net production in 2003, is located in Sutton County, west Texas. We have rights to drill and produce on 31,600 acres. Over the last several years, we have been conducting drilling programs targeting shallow Canyon sandstone formations. We have a 90%-100% working interest in most of the areas we are actively drilling. We drilled 18 wells in 2003 and plan to drill 12-20 additional wells in 2004 in order to maintain production levels.

- *Joaquin Field* — We operate and have rights to earn up to 5,000 acres in this property located just west of the Texas-Louisiana border in Shelby County, Texas. We drilled six wells in 2003, which produce Travis Peak sands at depths of 6,000-8,600 feet. We anticipate drilling 10-12 additional wells in 2004.

- *Talihina Field* — We acquired the majority of our acreage in this Arkoma basin field in 2002. We now have approximately 11,000 acres in this Jackfork formation play. In the 24 sections in which we have ownership, working interest varies from 19%-70%. We drilled our first well in late 2002, followed by two additional wells in 2003. We plan to drill six to ten additional wells in 2004 with follow up drilling dependent upon continuing step-out success. We also participated in four development wells in the nearby Panola and Wilburton fields.

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 2003, we drilled 6 exploratory and 13 development wells in this region with a success rate of 84%. All of the wells drilled during 2003, except one non-operated offshore well, were located in south Texas. We anticipate drilling 20-26 wells in this region in 2004, approximately half of which will be exploratory.

- *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 4,000-13,000 feet. In 2003, we drilled five Wilcox exploration wells, of which four were successful. In addition, we drilled eight Wilcox development wells. Normally, we generate these prospects and retain a 25%-60% working interest.

- *Vicksburg Trend* — We also pursue Vicksburg formation prospects primarily in our La Reforma Field in Hidalgo County. We drilled a successful initial test well in late 2002, drilled one additional well in 2003 and anticipate drilling two to three additional wells in 2004.

- *Other Gulf Coast* — We have minor, non-operated interests in 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, the Big Horn basin in Wyoming and the Los Angeles basin in California. As of December 31, 2003, these properties accounted for approximately 14% of our PV-10 value. In 2003, we drilled one well in Michigan and used the cash flow generated from these properties to fund drilling operations in our core operating areas.

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, 2003.

	Producing Wells			
	Natural Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent Region	716	466.4	22	11.2
Gulf Coast Region	221	90.1	28	10.2
Other Properties(1)	81	55.2	105	68.8
Total Company	1,018	611.7	155	90.2

(1) Michigan, California and Wyoming.

Oil and Natural Gas Reserves

The following table sets forth, as of December 31, 2003, 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, 2003 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. The reserve estimates and associated net revenues for our properties were audited by Netherland, Sewell & Associates, Inc., or NSAI.

	As of December 31, 2003				
	Natural Gas (MMcf)	Oil (Mbbls)	Total (MMcfe)	Future Net Revenues ($000)	PV-10 ($000)
Proved developed reserves	164,787	5,685	198,897	$ 805,936	$483,702
Proved undeveloped reserves	63,331	1,010	69,391	271,052	150,107
Proved reserves	228,118	6,695	268,288	$1,076,988	$633,809

In addition, incremental asset retirement obligations not reflected in the future net revenues above were $7.4 million and PV-10, net of those asset retirement obligations, was approximately $630 million.

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, 2003 spot price of $5.97 per MMBtu, adjusted by lease for Btu content, transportation fees and regional price differentials. Oil prices are based on a December 31, 2003 West Texas Intermediate posted price of $29.25 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.

Production

The following table presents certain information with respect to production attributable to our properties and average sales prices for the years ended December 31, 2003, 2002 and 2001.

	Year Ended December 31,		
	2003	2002	2001
Production: (a)			
Natural Gas (MMcf)	28,166	29,672	36,873
Oil (Mbbl)	838	1,003	1,230
Natural gas liquids (Mbbl)	258	288	373
Total (MMcfe)	34,741	37,417	46,491
Summary (MMcfe)			
Working interest (b)	34,741	34,959	41,966
Purchased VPP (c)	—	2,458	4,525
Total	34,741	37,417	46,491
Dedicated to Production Payment	(6,807)	(11,196)	(15,716)
Net Production	27,934	26,221	30,775
Average Price:			
Natural gas (per Mcf)	$ 4.79	$ 3.25	$ 3.90
Oil (per bbl)	25.34	20.52	20.67
Natural gas liquids (per bbl)	14.58	10.05	13.74
Total (per Mcfe) (d)	$ 4.60	$ 3.21	$ 3.75

(a) Production includes volumes dedicated to the Production Payment sold in February 2001. Please read Notes 1 and 2 to our Consolidated Financial Statements for more information on the Production Payment.

(b) We sold properties in 2002 and 2001 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.

(d) Excluding the non-cash effects of volumes delivered under the Production Payment sold in February 2001 and terminated derivative contracts associated with the acquisition of Medallion California Properties Company and related entities, our total average realized price per Mcfe was $5.05, $3.19 and $3.90 in 2003, 2002 and 2001, respectively. For further information, please read Item 7. "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, 2003. 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.

	Developed Acres		Undeveloped Acres	
State	Gross	Net	Gross	Net
Texas	92,874	55,716	33,053	21,287
Louisiana	31,014	23,720	11,474	8,124
Oklahoma	43,789	25,541	8,302	6,282
Michigan	12,620	6,733	138	138
Wyoming	61,851	39,746	27,750	23,151
Offshore	80,063	9,683	—	—
Other	12,672	6,091	9,039	1,877
Total	334,883	167,230	89,756	60,859

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, 2003, we participated in drilling 237 (120.1 net) wells with a success rate of 86%. During 2003, we participated in drilling 78 (55.4 net) wells with a success rate of 92%. Our drilling results for 2003 include 71 development wells and 7 exploration wells with success rates of 93% and 86%, 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, 2003, 2002 and 2001.

	Year Ended December 31,					
	2003		2002		2001	
Type of Well	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	—	—	1	0.8	2	0.5
Natural gas	66	49.3	28	13.4	63	29.0
Non-productive	5	2.9	5	1.2	6	3.4
Total	71	52.2	34	15.4	71	32.9
Exploratory:						
Oil	—	—	—	—	4	0.9
Natural gas	6	2.7	10	4.5	23	7.0
Non-productive	1	0.5	9	2.2	8	1.8
Total	7	3.2	19	6.7	35	9.7

As of December 31, 2003, we were participating in the drilling of 8 (5.2 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 gas properties;
- establish maximum rates of production from oil and 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 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 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 gas business involves a variety of operating risks, including the risk of fires, explosions, well blow-outs, pipe failure, 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 or other property or equipment, or damage to the environment. 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 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 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 and subject to wide fluctuations in response to a variety of factors including the following:

- relatively minor changes in the supply of, and demand for, oil and natural gas;
- market uncertainty;
- political conditions in international oil producing regions;
- weather conditions;
- domestic and foreign government regulations and taxes;
- price and availability of alternative fuels; and
- overall economic conditions.

As oil and natural gas prices decline, we are affected in two significant ways. First, we are paid less for our oil and natural gas. Second, exploration and development activity may decline as some projects may become uneconomic and either are delayed or eliminated. Accordingly, a decline in oil or natural gas prices may have adverse effects on our cash flow, liquidity and profitability. It is impossible to predict future oil and natural gas price movements.

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 gas properties. In the past, we have funded these capital expenditures with cash flow from operations, funds from long-term debt financings, including bank financing secured by our oil and gas assets, and funds from equity financings. Our future cash flows are subject to a number of factors, including the following:

- prices 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 gas properties and our cash flow in evaluating our prospects for growth and profitability.

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 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. 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, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and to assess possible environmental 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 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 subordinated 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.

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.

Therefore, the estimates of the quantities of oil and natural gas and the expected future net revenues computed by different engineers or by the same engineers (but at different times) may vary significantly. 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 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 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 gas industry in general.

Our operating activities involve significant risks that are inherent in the oil and gas industry.

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

- fires;
- explosions;
- well blowouts;
- 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 or other property or equipment, or damages to the environment. 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:

- the presence of unanticipated pressure or irregularities in formations;
- equipment failures or accidents;
- title problems;
- weather conditions;

- compliance with governmental requirements; and
- shortages or delays in obtaining drilling rigs or in the delivery of equipment and services.

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.

We may be unable to produce sufficient amounts of oil and natural gas and, as a result, our profitability and cash flow may 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. 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 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 gas companies, other independent oil and gas concerns and individual producers and operators in most aspects of our business, including the following:

- the acquisition of oil and gas businesses and properties;
- the exploration, development, production and marketing of oil and natural gas;
- the acquisition of properties and equipment; and
- the 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. 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. We, as an owner or lessee and operator of oil and gas properties, 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 the location of drilling or the level of production allowed from a well, affect the cost, terms and availability of oil and natural gas transportation by pipeline, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations, subject the lessee to liability for pollution damages, and require suspension or cessation of operations in affected areas.

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 oil and gas regulatory environment could change in ways that could substantially increase the cost of complying with the requirements of environmental and other regulations. 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. 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.

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.

Our ability to transport our oil and natural gas to market at commercially acceptable prices depends on, among other factors, the following:

- the availability and capacity of gathering systems and pipelines;
- changes in supply and demand; and
- general economic conditions.

Our inability to respond appropriately to changes in these 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 could 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, 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 business.

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 long-term impact that terrorist attacks and the threat of terrorist attacks may have on our business is not known at this time. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns or terrorist attacks may adversely impact our business in unpredictable ways.

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, 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 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;
- we fail to make timely deliveries; and
- a sudden unexpected event materially impacts oil or natural gas prices.

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

The oil and 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 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 could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

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

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.

The covenants in our debt and financing arrangements restrict our financial and operating flexibility and our failure to comply with them could have a material adverse effect on our business, financial condition and results of operations.

Our debt and financing arrangements contain a number of significant limitations that restrict our ability to, among other things, borrow additional money and sell assets. These restrictions may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition activities. The restrictions may also affect our ability to obtain additional future financing for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes.

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.

Investors in our securities may encounter difficulties in obtaining, or may be unable to obtain, recoveries from Arthur Andersen LLP with respect to its audits of our financial statements.

On March 14, 2002, our previous independent public accountant, Arthur Andersen LLP, was indicted on federal obstruction of justice charges arising from the federal government's investigation of Enron Corp. On June 15, 2002, a jury returned with a guilty verdict against Arthur Andersen following a trial. As a public company, we are required to file with the Securities and Exchange Commission periodic financial statements audited or reviewed by an independent public accountant. In July 2002, we engaged Ernst & Young LLP to serve as our new independent auditors for fiscal 2002. However, included in this annual report on Form 10-K for the year ended December 31, 2003 is financial data and other information for the year ended December 31, 2001 that was audited by Arthur Andersen. Investors in our securities may encounter difficulties in obtaining, or be unable to obtain, from Arthur Andersen with respect to its audits of our financial statements, relief that may be available to investors under the federal securities laws against auditing firms.

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 gas companies, other independent oil and 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 10 to our Consolidated Financial Statements for information regarding our derivative instruments.

Other than the amortization of deferred revenue associated with the Production Payment, no customer accounted for more than 10% of our revenues in 2003, 2002 or 2001.

Seasonality

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

Employees

At December 31, 2003, we employed a total of 129 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 11 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, 2003.

PART II

Item 5. *Market For Registrant's Common Equity and Related Stockholder Matters.*

Our common stock is traded on the New York Stock Exchange under the symbol "KCS." As of March 5, 2004, there were approximately 949 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 2003 and 2002, 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 2002		
First Quarter	$3.32	$1.63
Second Quarter	4.01	1.75
Third Quarter	2.70	1.14
Fourth Quarter	2.25	1.15
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 12, 2004, the last reported sale price of our common stock on the New York Stock Exchange was $10.91 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, 2003.

	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	1,885,722(1)	$4.36	2,736,674(2)
Total	1,885,722(1)	$4.36	2,736,674(2)

(1) Represents options granted under the KCS Energy, Inc. 2001 Employee and Directors Stock Plan.

(2) Includes 1,289,493 shares authorized for issuance pursuant to our 2001 Employee and Directors Stock Plan, 756,595 shares authorized for issuance pursuant to our employee stock purchase program and 690,586 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. Please read Notes 2 and 4 to our Consolidated Financial Statements. 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 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 10 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, 2003, grants of 681,404 restricted shares were outstanding under the 2001 Stock Plan.

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.

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.

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, 2003. 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. This information should be read in conjunction with "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.

	Year Ended December 31,				
	2003(1)	2002(2)	2001	2000	1999
	(In thousands, except ratios)				
Income Statement Data:					
Oil and natural gas revenue	$131,940	$ 74,820	$111,345	$190,511	$134,124
Amortization of deferred revenue of production payment sold in 2001	27,886	45,182	63,089	—	—
Other, net	5,001	(1,183)	17,557	1,478	4,494
Total revenues and other	164,827	118,819	191,991	191,989	138,618
Costs and expenses:					
Lease operating expenses	26,461	25,246	30,456	27,801	28,751
Production taxes	8,145	5,589	8,195	6,605	3,524
General and administrative expenses	8,011	8,255	8,885	8,417	9,797
Stock compensation	2,715	782	1,419	—	—
Bad debt expense	339	215	4,074	400	50
Restructuring cost	—	—	—	—	1,886
Asset retirement obligation accretion	1,116	—	—	—	—
Depreciation, depletion and amortization	47,885	49,251	58,314	50,451	50,967
Total operating costs and expenses	94,672	89,338	111,343	93,674	94,975
Operating income	70,155	29,481	80,648	98,315	43,643
Interest and other income	112	279	1,319	101	702
Interest expense (contractual interest for 2000 was $36,220)	(20,970)	(19,945)	(21,799)	(41,460)	(40,005)
Income before reorganization items and income taxes	49,297	9,815	60,168	56,956	4,340
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	49,297	9,815	57,220	41,523	4,340
Federal and state income tax expense (benefit)	(20,229)	13,763	(8,359)	—	—
Net income (loss) before cumulative effect of accounting change	69,526	(3,948)	65,579	41,523	4,340
Cumulative effect of accounting change, net of tax	(934)	(6,166)	—	—	—
Net income (loss)	68,592	(10,114)	65,579	41,523	4,340
Dividends and accretion of issuance costs on preferred stock	(909)	(1,028)	(1,761)	—	—

	Year Ended December 31,				
	2003(1)	2002(2)	2001	2000	1999
	(In thousands, except ratios)				
Income (loss) available to common stockholders	$ 67,683	$(11,142)	$ 63,818	$ 41,523	4,340
Earnings (loss) per common share:					
Basic income (loss)	$ 1.71	$ (0.31)	$ 2.02	$ 1.42	$ 0.15
Diluted income (loss)	$ 1.61	$ (0.31)	$ 1.69	$ 1.42	$ 0.15
Other Financial Data:					
Net cash provided by operating activities	71,022	20,825	183,419	128,007	71,463
Capital expenditures	88,791	47,508	87,192	69,078	59,160
Ratio of earnings to fixed charges	3.20	1.43	3.50	1.97	1.08
Balance Sheet Data (at end of period):					
Working capital (deficit)	(20,792)	(16,479)	(3,053)	49,230(3)	(10,950)(3)
Total assets	342,966	268,133	346,726	347,335	284,932
Long-term debt:					
Bank credit facilities	17,000	500	—	76,705(4)	107,095(4)
11% Senior Notes	—	61,274	79,800	150,000	149,724(4)
8⅞% Senior Subordinated Notes	125,000	125,000	125,000	125,000	125,000(4)
Deferred revenue	38,696	66,582	111,880	—	—
Preferred stock	—	12,859	15,589	—	—
Stockholders' equity (deficit)	98,031	(42,716)	(39,460)	(108,320)	(149,843)

(1) Includes a $19.0 million non-cash 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."

(2) 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.

(3) Excludes debt classified as current liability.

(4) 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, 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 "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 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, well blowouts, pipe failure, spills, explosions and other unforeseen hazards);
- our ability to effectively 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;
- 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 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, 2003 was one of the most successful in our history. We focused on a low-risk drilling program in our core areas of operation where we experienced significant increases in oil and natural gas reserves and production. We drilled 78 wells during 2003, of which 72 were completed, resulting in a 92% success rate. Production from our properties averaged 77.2 MMcf per day of natural gas and 3,002 barrels of oil and natural gas liquids per day, or 95.2 MMcfe per day for 2003. We increased production 24%, from an average of 83.9 MMcfe per day during the first quarter to an average of 104.1 MMcfe per day during the fourth quarter. Oil and natural gas reserves increased during 2003 to 268.3 Bcfe, which include reserve additions of 93.8 Bcfe, replacing 336% of our 2003 net production. Including positive reserve revisions of 10.5 Bcfe, our overall reserve replacement rate was 373%.

We took several major steps during 2003 to further strengthen our financial condition, lower interest costs and provide increased financial flexibility. The balance of our outstanding Series A Convertible Preferred Stock was converted into shares of our common stock. This conversion simplified our overall capital structure and eliminated the 5% dividend obligation associated with the preferred stock. In the first quarter we paid off our maturing senior note obligations. In the fourth quarter, we amended and restated our bank credit facility, which increased our revolving credit capacity to $100 million and significantly reduced our borrowing costs. We also completed a public offering of 6.9 million shares of our common stock. We used a portion of the net proceeds of approximately $52 million to repay borrowings under our bank credit facility and to accelerate our drilling program in certain core areas. Our successful drilling program, along with strong oil and natural gas prices and proceeds from our public common stock offering, allowed us to reduce debt from $186.8 million, or $0.95 per Mcfe of reserves, at the beginning of the year to $142.0 million, or $0.53 per Mcfe of reserves, at the end of the year.

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 2003, we drilled 58 wells in this region with a success rate of 95%. We have a multi-year inventory of locations in the Mid-Continent region and plan to increase the level of drilling in our Elm Grove, Talihina and Joaquin fields and to continue the development program in our Sawyer Canyon Field in 2004.

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 2003, we drilled 6 exploratory and 13 development wells in this region with a success rate of 84%. All of the wells drilled during 2003, except one non-operated offshore well, were located in south Texas. We anticipate drilling 20-26 wells in this region in 2004, approximately half of which will be exploratory.

We believe that the steps taken during 2003 position us to grow 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 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 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 government regulations and taxes, the price and availability of alternative fuels and overall economic conditions.

The price we receive for our natural gas production is generally 7 to 12 cents below NYMEX prices. 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 below the Koch West Texas Intermediate posted prices for sweet crude in Texas / New Mexico.

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 realized discounted price 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 $0.29 per Mcfe in 2003 and to increase realized prices by $0.20 per Mcfe in 2002 and $0.02 per Mcfe in 2001.

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 $0.16, $0.18 and $0.17 per Mcfe in 2003, 2002 and 2001, respectively.

Production. The primary factors affecting our production levels are capital availability, the success of our drilling program and, in recent years, the winding down and expiration of our purchased VPP program in 2002.

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, with our Senior Note obligations having been met, we were able to direct our cash flow to our drilling operations and increase production levels throughout the year.

In 2001, 4.5 Bcfe, or 10%, of our 2001 production and in 2002, 2.5 Bcfe, or 7%, of our 2002 production was derived from our purchased VPP program. We have not made any VPP investments since 1999 as our primary focus since that time has been to add oil and natural gas reserves through the drill bit. 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 sold in 2001 discussed below. However, we view the net production after our delivery obligations associated with the Production Payment as more important because that is what generates cash flow. For example, while total production declined from 37.4 Bcfe in 2002 to 34.7 Bcfe in 2003 due to the expiration of purchased VPP's, our net production actually increased from 26.2 Bcfe in 2002 to 27.9 Bcfe in 2003 as delivery obligations associated with the Production Payment declined from 11.2 Bcfe in 2002 to 6.8 Bcfe in 2003. This 1.7 Bcfe increase in net production in 2003 resulted in incremental cash flow of approximately $8.6 million.

Sale of Production Payment. In February 2001, we sold a 43.1 Bcfe production payment, referred to in this annual report on Form 10-K as the Production Payment, in connection with our emergence from bankruptcy. 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 price 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 17%, 38% and 36% of our oil and gas revenue during 2003, 2002 and 2001, respectively. At December 31, 2003, 9.3 Bcfe remained to be delivered under the Production Payment of which 5.2 Bcfe will be delivered in 2004, 3.9 Bcfe 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 largely because we are focused in certain core areas which allows us to operate efficiently. Lease operating expenses were $30.5 million in 2001, $25.2 million in 2002 and $26.5 million in 2003. In terms of gross dollars, these costs fluctuated primarily due to levels of production and workover activities. In order to measure our operating performance, we monitor lease operating expenses on a per unit of production basis excluding the production received under our purchased VPP program because volumes received under the purchased VPP program were free from these expenses as discussed above. Lease operating expenses (excluding production from purchased VPPs) per Mcfe were $0.76 in 2003, $0.72 in 2002 and $0.73 in 2001.

General and administrative expenses are monitored closely with the objective of operating an efficient organization with an appropriate cost structure. In 2001 and 2002, we reduced our staff in response to limited capital availability and curtailed drilling activity. In 2003, we added staff modestly in response to our resumed growth. General and administrative expenses were $8.9 million, or $0.19 per Mcfe, in 2001, $8.3 million, or $0.22 per Mcfe in 2002 and $8.0 million, or $0.23 per Mcfe in 2003.

Factors Affecting Comparability

Income Taxes. Our 2003 results included a $19.0 million non-cash income tax benefit resulting from the reversal of a portion of our valuation allowance against net deferred income tax assets while 2002 includes a $15.9 million non-cash write-down to zero of the book value of net deferred tax assets.

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 thereby utilizing a portion of our deferred tax asset and the future outlook for taxable income has improved substantially. Oil and natural gas prices have improved significantly and are expected to remain relatively high for the foreseeable future based on existing available information, including current prices quoted on the New York Mercantile Exchange. Therefore, during 2003, we reversed approximately $19 million of the valuation allowance related to expected taxes on future years' taxable income, which is reflected as an income tax benefit in the condensed statements of consolidated operations.

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 Obligation" and recorded a $0.9 million charge against earnings as a cumulative effect of an accounting change.

Sale of Emission Credits. We sold emission credits totaling $4.9 million and $9.3 million in 2003 and 2001, respectively. We did not sell any emission credits in 2002. We currently do not anticipate any significant emission credit sales in 2004.

Purchased VPPs. As discussed above under "Major Influences on Results of Operations — Production," the decision to cease purchases of VPPs in 1999 and the expiration of volumes received under the purchased VPP program affects the comparability of our production, lease operating expenses and production taxes.

Stock Compensation. Stock compensation was $2.7 million, $0.8 million and $1.4 million in 2003, 2002 and 2001, 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.

Reorganization. In 2000, we conducted a reorganization in bankruptcy, and the United States Bankruptcy Court for the District of Delaware confirmed our plan of reorganization in 2001. Under the reorganization plan, holders of our senior notes and senior subordinated notes received all accrued and unpaid interest, our senior noteholders received a partial pre-payment of principal, our trade creditors were paid in full and our stockholders retained 100% of their common stock, subject to dilution upon conversion of the $30 million of Series A Convertible Preferred Stock sold in connection with our emergence from bankruptcy. The Consolidated Statement of Operations for 2001 included $2.9 million of net costs associated with the reorganization.

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 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. 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 determinations 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 $173 million have remaining lives ranging from 9 to

19 years, with the majority having a life in excess of 15 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 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. We adopted SFAS No. 143 as of January 1, 2003. As a result, net property, plant and equipment was increased by $10.2 million, an asset retirement obligation of $11.1 million was recorded and a $0.9 million charge against net income was reported in the first quarter of 2003 as a cumulative effect of a change in accounting principle.

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.

SFAS No. 143 requires a cumulative adjustment to reflect the impact of implementing the statement had the rule been in effect since inception. We, therefore, calculated the cumulative accretion expense on the asset retirement obligation liability and the cumulative depletion expense on the corresponding property balance. The sum of these cumulative expenses was compared to the depletion expense originally recorded. As the historically recorded depletion was lower than the cumulative expense calculated under SFAS No. 143, the difference resulted in a loss that we recorded as cumulative effect of a change in accounting principle as of January 1, 2003.

Upon implementation, we also had to determine if the statement required us to recalculate our historical full-cost ceiling test. We chose not to recalculate our historical full-cost ceiling test even though our historical oil and gas property balance would have been higher had we applied the statement from its inception. We believe this approach is appropriate because SFAS No. 143 is silent on this issue and was not effective during the prior implementation test periods. If a recalculation of the historical full-cost ceiling test resulted in impairment, the charge would have increased the cumulative loss recorded upon adoption and reduced depletion expense subsequent to adoption.

We also had to determine how to incorporate the asset retirement obligations into our 2003 quarterly calculations of our full-cost ceiling test. SFAS No. 143 is silent with respect to this issue and although there are various views, we elected to continue to include the capitalized cost of our asset retirement obligation in our oil and gas property balance and exclude the cash outflow associated with future abandonment cost from future development cost when calculating the pre-tax present value of our future net revenues. This results in both a higher ceiling test threshold and a higher net oil and gas property balance. Another widely contemplated view is to include the undiscounted asset retirement obligation as part of future development cost, essentially reducing the pre-tax present value of future net revenues and to net the asset retirement obligation recorded on the balance sheet against the oil and gas property balance. We believe that our approach is more conservative although at the present time there is no material difference in our ceiling test calculation using either of these methods.

Prospectively, our depletion expense will be reduced because we will deplete a discounted asset retirement cost rather than the undiscounted value previously depleted. The lower depletion expense under SFAS No. 143 is offset, however, by higher accretion expense, which reflects increases in the discounted asset retirement obligation over time.

Derivatives

We use commodity derivative contracts on a limited basis 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 trading purposes.

Results of Operations

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 volumetric production payment, or 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 9 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 unit-of-production 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.

Income before income taxes and cumulative effect of accounting change for 2002 was $9.8 million compared to $57.2 million in 2001. Dramatically lower natural gas prices, lower non-oil and natural gas revenue and lower production were partially offset by significantly lower operating, reorganization and interest expenses. Income tax expense for 2002 was $13.8 million compared to an income tax benefit of $8.4 million in 2001. We reported a net loss before cumulative effect of accounting change of $3.9 million, or $0.14 per basic and diluted share, as a result of the non-cash income tax expense in 2002. In 2002, the cumulative effect of accounting change to the unit-of-production method of amortization of oil and gas property costs was a $6.2 million loss, or a $0.17 per basic and diluted share. Loss available to common stockholders in 2002 was $11.1 million, or $0.31 per basic and diluted share, compared to income available to common stockholders of $63.8 million, or $2.02 per basic share and $1.69 per diluted share in 2001.

	Year Ended December 31,		
	2003	2002	2001
Production: (a)			
Natural gas (MMcf)	28,166	29,672	36,873
Oil (Mbbl)	838	1,003	1,230
Natural gas liquids (Mbbl)	258	288	373
Total (MMcfe)	34,741	37,417	46,491
Summary (MMcfe)			
Working interest (b)	34,741	34,959	41,966
Purchased VPP (c)	—	2,458	4,525
Total	34,741	37,417	46,491
Dedicated to Production Payment	(6,807)	(11,196)	(15,716)
Net Production	27,934	26,221	30,775
Average Price:			
Natural gas (per Mcf)	$ 4.79	$ 3.25	$ 3.90
Oil (per bbl)	25.34	20.52	20.67
Natural gas liquids (per bbl)	14.58	10.05	13.74
Total (per Mcfe) (d)	$ 4.60	$ 3.21	$ 3.75
Revenue ($000's):			
Natural gas	$134,833	$ 96,531	$143,882
Oil	21,231	20,578	25,428
Natural gas liquids	3,762	2,893	5,124
Total	$159,826	$120,002	$174,434

(a) Production includes volumes dedicated to the Production Payment sold in February 2001. Please read Notes 1 and 2 to our Consolidated Financial Statements for more information on the Production Payment.

(b) We sold properties in 2002 and 2001 to reduce debt.

(c) We discontinued making new investments in VPPs in 1999 and final deliveries were received in November 2002.

(d) Excluding the non-cash effects of volumes delivered under the Production Payment sold in February 2001 and terminated derivative contracts associated with the acquisition of Medallion California Properties Company and related entities, our total average realized price per Mcfe was $5.05, $3.19 and $3.90 in 2003, 2002 and 2001, respectively.

Natural Gas Revenue. In 2003, natural gas revenue was $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.

In 2002, natural gas revenue was $96.5 million compared to $143.9 million in 2001 as a result of a 17% decrease in realized natural gas prices and a 20% decline in production. The production decline was primarily due to the sale of oil and gas properties and the expiration of certain volumetric production payments. Furthermore, the natural decline of producing properties was not fully offset by new production largely due to our curtailed capital investment program.

Oil and Liquids Revenue. In 2003, oil and liquids revenue increased $1.5 million to $25.0 million primarily due to a 25% increase in the weighted average realized price offset by a 15% decrease in production. The decrease in production was attributable to the sale of non-core oil and gas properties in 2002 and natural decline of oil properties as the 2003 drilling program focused almost entirely on natural gas prospects.

In 2002, oil and liquids revenue decreased $7.1 million to $23.5 million primarily due to a 19% decrease in production. The decrease in production in 2002 was attributable to the sale of oil and gas properties and the natural declines of producing properties.

Other, net. 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 2004.

Other, net decreased from $17.6 million in 2001 to a net cost of $1.2 million in 2002. Of the $17.6 million in 2001, $9.3 million was from the sale of emission reduction credits and $7.7 million was from non-cash gains on derivative instruments that were not designated as oil and natural gas hedges when we adopted SFAS No. 133. The remainder was primarily attributable to marketing and transportation revenue incidental to our oil and gas operations. In 2002, the net cost of $1.2 million was primarily attributable to marketing and transportation activities.

Lease Operating Expenses

For the year ended December 31, 2003, lease operating expenses, or LOE, increased 5% to $26.5 million, compared to $25.2 million in 2002. On a per unit basis, LOE was $0.76 per Mcfe of working interest production in 2003 compared to $0.72 per Mcfe in 2002. The increase was primarily attributed to a higher level of workover activity on oil and gas wells in 2003.

For the year ended December 31, 2002, LOE decreased 17% to $25.2 million ($0.72 per Mcfe of working interest production), compared to $30.5 million ($0.73 per Mcfe of working interest production) in 2001. Increased focus on cost reductions and operating efficiency along with lower production largely due to the sale of certain non-core properties contributed to the reductions.

Production Taxes

Production taxes increased $2.5 million to $8.1 million in 2003, compared to $5.6 million in 2002. Production taxes are generally based on a percentage of revenue, excluding revenue from our now-terminated VPP program. The increase was primarily attributable to higher oil and natural gas revenue associated with higher average realized prices and higher production tax rates in Louisiana where we significantly increased our production in the Elm Grove Field.

Production taxes decreased $2.6 million to $5.6 million in 2002 compared to $8.2 million in 2001 due to lower oil and natural gas revenue associated with the decrease in working interest production and lower average realized prices.

General and Administrative Expenses

General and administrative expenses decreased $0.3 million to $8.0 million in 2003, compared to $8.3 million in 2002. The 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.

General and administrative expenses in 2002 decreased $0.6 million to $8.3 million compared to $8.9 million in 2001. The decrease in 2002 resulted from lower labor costs associated with a reduced work force, partially offset by an increase in insurance premiums and employment severance payments.

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

Stock compensation was $0.8 million in 2002 compared to $1.4 million in 2001. These amounts reflect the non-cash amortization of restricted stock grants. No expense was recorded pursuant to FIN 44 as the options subject to variable accounting discussed above were "out-of-the-money" during 2002 and 2001. The 2001 expense amount includes incremental costs associated with initial grants made upon our emergence from bankruptcy to compensate for a portion of stock options previously issued but cancelled in connection with our plan of reorganization.

Bad Debt Expense

Bad debt expense was $0.3 million in 2003 compared to $0.2 million in 2002. Bad debt expense was $4.1 million in 2001, primarily due to an allowance against receivables due from various Enron entities that are now in bankruptcy for oil and natural gas sales and derivative instruments. We ceased all sales to Enron entities after November 2001.

Accretion of Asset Retirement Obligation

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

Depreciation, Depletion and Amortization

For the year ended December 31, 2003, depreciation, depletion and amortization expense was $47.9 million compared to $49.3 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.

Effective January 1, 2002, we began amortizing our oil and gas properties using the UOP method based on proved reserves. This change resulted in additional amortization of $6.2 million through December 31, 2001, which is classified as a cumulative effect of accounting change, net of tax, in 2002. For the year ended December 31, 2002, depreciation, depletion and amortization decreased $9.1 million to $49.3 million. The decrease reflects reduced production and a lower depletable base.

Interest and Other Income

Interest and other income was $0.1 million in 2003 compared to $0.3 million in 2002 and $1.3 million in 2001. These amounts primarily represent interest income earned on accumulated cash and cash equivalents.

Interest Expense

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.

In 2004, we anticipate a significant reduction in interest expense as a result of lower interest rates associated with our amended and restated bank credit facility and lower average borrowings following our 2003 public common stock offering. The proceeds of our 2003 public common stock offering were initially used to repay debt.

Interest expense was $19.9 million in 2002 compared to $21.8 million in 2001. The decrease reflected the trend of lowering outstanding debt and, to a lesser extent, lower interest rates on the bank credit facility, partially offset by a $1.1 million write off of deferred financing costs in December 2002.

Reorganization Items

We completed our bankruptcy proceedings in 2001. Accordingly, there were no reorganization items in 2003 or 2002. For the year ended December 31, 2001, we recorded $2.9 million of reorganization items, primarily for legal and financial advisory services in connection with our completed bankruptcy proceedings.

Income Taxes

Income tax benefits were $20.2 million in 2003 compared to income tax expense of $13.8 million in 2002 and income tax benefits of $8.4 million in 2001. These amounts reflect changes in our valuation allowance against net deferred income tax assets.

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 thereby utilizing a portion of our deferred tax asset and the future outlook for taxable income has improved substantially. Oil and natural gas prices have improved significantly and are expected to remain relatively high for the foreseeable future based on existing available information, including current prices quoted on the New York Mercantile Exchange. Therefore, during 2003, we reversed approximately $19 million of the valuation allowance related to expected taxes on future years' taxable income, which is reflected as an income tax benefit in the condensed statements of consolidated operations.

In connection with the adoption of SFAS No. 133 on January 1, 2001, we recorded a liability of $43.8 million representing the fair market value of our derivative instruments upon adoption and an after-tax charge to other comprehensive income of $28.5 million from the cumulative effect of a change in accounting principle. During 2001, we reclassified $23.9 million of the liability as a non-cash reduction to oil and natural gas revenues and reduced the valuation allowance related primarily to net operating losses, for a related tax benefit of $8.4 million.

Liquidity and Capital Resources

Our liquidity and capital resources improved significantly during 2003. In January 2003, we amended and restated our bank credit facility to increase our borrowing availability and paid off the maturing senior note obligations. We also accelerated our drilling program, resulting in increased production and oil and natural gas reserves. We drilled 78 wells during 2003 with a success rate of 92%. We increased production 24%, from an average of 83.9 MMcfe per day during the first quarter to an average of 104.1 MMcfe per day during the fourth quarter. The increase in production coupled with a strong natural gas and oil price environment resulted in a substantial increase in cash flow as discussed below.

We took several major steps during 2003 to further strengthen our financial condition, lower interest costs and provide increased financial flexibility. The balance of our outstanding Series A Convertible Preferred Stock was converted into shares of our common stock. This conversion simplified our overall capital structure and eliminated the 5% dividend obligation associated with the preferred stock. In the first quarter we paid off our maturing senior note obligations. In the fourth quarter of 2003, we amended and restated our bank credit facility, which increased our revolving credit capacity to $100 million and significantly reduced our borrowing costs. We also completed a public offering of 6.9 million shares of our common stock. We used a portion of the net proceeds of approximately $52 million to repay borrowings under our bank credit facility and to accelerate our drilling program in certain core areas. Our successful drilling program, along with strong oil and natural gas prices and proceeds from our public common stock offering, allowed us to reduce debt during 2003 from $186.8 million, or $0.95 per Mcfe of reserves, at the beginning of the year to $142.0 million, or $0.53 per Mcfe of reserves, at the end of the year.

With the completion of the steps outlined above, we believe that we are positioned to capitalize on the current strong natural gas and oil price environment, to focus on developing our multi-year prospect inventory, to increase reserves and production in our core areas and to further reduce debt per Mcfe.

Our primary cash requirements are for exploration, development and acquisition of oil and gas properties, operating expenses and debt service.

For 2004, we have budgeted $105 million for capital investments in natural gas and oil properties and anticipate drilling over 100 wells. Of the $105 million, we anticipate spending approximately $44 million in the Elm Grove Field, $14 million at the Joaquin Field, $6 million at the Sawyer Canyon Field, $3 million at the Talihina Field, $13 million at other Mid-Continent properties, $13 million on the Gulf Coast exploration program and $12 million on the Gulf Coast development drilling program. We expect to fund our 2004 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.

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, 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 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.

Net cash provided by operating activities for 2002 was $20.8 million compared to $183.4 million in 2001. Cash provided by operating activities in 2001 was significantly impacted by the execution of our plan of reorganization, which included net proceeds of $175.0 million from the Production Payment sold in February 2001, the payment of $71.5 million of interest expense (including $49.1 million that pertained to prior years) and the $28.0 million cost of terminating certain derivative instruments in connection with our emergence from bankruptcy. Cash provided by operating activities during 2002 was negatively impacted by lower realized natural gas prices and lower production.

Investing Activities

Net cash used in investing activities in 2003 was $79.0 million, including $78.1 million invested in oil and gas properties, compared to net cash used in investing activities of $18.1 million in 2002. 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, 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 are not reflected in the net cash used in investing activities above until payment is 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.

Capital expenditures for the year ended December 31, 2001 were $87.2 million, including $42.9 million used for development activities, $26.8 million used for the acquisition of proved reserves, $15.3 million used for lease acquisitions, seismic surveys and exploratory drilling and $2.2 million used for other assets.

Financing Activities

Net cash provided by financing activities in 2003 was $3.2 million compared to net cash used in financing activities of $18.8 million in 2002. In 2003, net proceeds from the 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

On September 16, 2003, we, along with two of our 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. 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.

On November 26, 2003, in a public offering under our shelf registration statement, we sold 6.0 million shares of our common stock at $8.00 per share. On December 11, 2003, the underwriters exercised their over-allotment option and we sold an additional 0.9 million shares of common stock at $8.00 per share. We used a portion of the net proceeds of approximately $52.0 million from the public offering and the exercise of the over-allotment option to repay borrowings under our bank credit facility and to accelerate our drilling program in certain core areas, including the Elm Grove, Joaquin and Talihina fields, where we have accumulated a substantial drilling prospect inventory.

As of December 31, 2003, there were $144.8 million remaining under our shelf registration statement.

Bank Credit Facility

On November 18, 2003, we amended and restated our bank credit facility with a group of commercial bank lenders. The bank credit facility is used for general corporate purposes, including working capital, and to support our capital expenditure program. The bank credit facility provides up to $100 million of revolving borrowing capacity and matures on November 20, 2006. The maturity date will be October 17, 2005 if our 8⅞% Senior Subordinated Notes are not fully refinanced or repaid by October 14, 2005. Borrowing capacity under the bank credit facility is subject to a borrowing base initially set at $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. Substantially all of our assets, including the stock of all of our subsidiaries, are pledged to secure the bank credit facility. Further, each of our subsidiaries has guaranteed our obligations under the bank credit facility.

Borrowings under the bank credit facility bear interest, at our option, at an interest rate of LIBOR plus 2.25% to 3.0% or the greater of (1) the Federal Funds Rate plus 0.5% or (2) the Base Rate, plus 0.5% to 1.25%, depending on utilization. These rates will decrease by 0.5% after the final deliveries are made in connection with the Production Payment discussed in Note 2 to our Consolidated Financial Statements and the lien on the subject property is released. A commitment fee of 0.5% per year is paid on the unused availability under the bank credit facility. Financing fees pertaining to the bank credit facility are being amortized over the life of the facility. Deferred financing fees of $2.8 million associated with the bank credit facility prior to it being amended and restated in November 2003 and an early termination fee of $0.5 million paid to a previous lender were charged to interest expense during the fourth quarter of 2003.

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 requirements for hedging a portion of our 2004 oil and natural gas production, 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. Financial covenants require us to, among other things: (1) maintain a ratio of Adjusted EBITDA (earnings before interest, taxes, depreciation, depletion, amortization, other non-cash charges and exploration expenses minus amortization of deferred revenue attributable to Production Payment sold in February 2001) to cash interest payments of at least 2.50 to 1.00; (2) maintain a ratio of consolidated current assets to consolidated current liabilities (excluding the current portion of indebtedness for borrowed money and the face amount of letters of credit) of not less than (1)0.80 to 1.00 until March 31, 2004, (2)0.90 to 1.00 from April 2004 until September 30, 2004 and (3) 1.00 to 1.00 at all times after September 30, 2004 (any unused portion of the commitment amount of the bank credit facility is deemed to be a current asset of ours for purposes of this calculation); and (3) not enter into hedging transactions covering more than 80% of projected production from our proved developed producing reserves for the period of such transactions.

The bank credit facility also contains customary events of default, including any defaults by us in the payment or performance of any other indebtedness equal to or exceeding $5.0 million.

As of December 31, 2003, $17.0 million was outstanding under the bank credit facility, the weighted average interest rate was 3.6% and $82.0 million was available for additional borrowings We were also in compliance with all covenants under the bank credit facility as of that date.

Contractual Cash Obligations

The following table summarizes our future contractual cash obligations as of December 31, 2003 (in thousands).

Payments Due by Period

	Total	Less than 1 year	1-3 Years	3-5 Years	More than 5 years
		(In thousands of dollars)			
Long-term debt	142,000	—	142,000	—	—
Operating leases	2,739	1,561	1,141	37	—
Unconditional purchase obligations	6,986	3,331	3,655	—	—
	151,725	4,892	146,796	37	—

The above table does not include the liability for dismantlement, abandonment and restoration cost of oil and gas properties. See Note 1 to our Consolidated Financial Statements for further discussion.

Other Commercial Commitments

In connection with the Production Payment, we have obligations to deliver 5.2 Bcfe in 2004, 3.9 Bcfe in 2005 and 0.3 Bcfe in 2006. As of December 31, 2003, we had $2.4 million of surety bonds that remain outstanding until specific events or projects are completed and any claims that may be made are settled.

As of December 31, 2003, we had outstanding a $1.0 million standby letter of credit supporting hedge transactions with one counterparty. This letter of credit was cancelled upon the settlement of the related hedges in the first quarter of 2004.

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

Effective January 1, 2003, we adopted SFAS No. 143. 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 period 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, our 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. Subsequent to adoption, the effect of the change in accounting principle was a $0.4 million additional non-cash charge against income.

Effective January 1, 2002, we 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, we had computed amortization on the basis of future gross revenue. We determined that the change to the UOP method was preferable under GAAP as, 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, we 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.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51," or FIN 46. FIN 46 requires a company to consolidate a variable interest entity, or VIE, if it has a variable interest or combination of variable interests that is exposed to a majority of the entity's expected losses if they occur, receives a majority of the entity's expected residual returns if they occur, or both. In addition, more extensive disclosure requirements apply to the primary and other significant variable interest owners of the VIE. This interpretation applies immediately to VIEs created after January 31, 2003, and to VIEs in which an enterprise obtains an interest after that date. FIN 46 is also generally effective for the first fiscal year or interim period ending after December 15, 2003, to VIEs in which a company holds a variable interest that is acquired before February 1, 2003. We have concluded that we do not have any interest in VIEs and that this interpretation has no impact on our consolidated financial statements.

In May 2003, the FASB issued SFAS No. 150 "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity". SFAS No. 150 establishes standards on how we classify and measure certain financial instruments with characteristics of both liabilities and equity. The statement requires that we classify as liabilities the fair value of all mandatorily redeemable financial instruments that had previously been recorded as equity or elsewhere in the consolidated financial statements. This statement is effective for financial instruments entered into or modified after May 31, 2003, and is otherwise effective for all existing financial instruments beginning in the third quarter of fiscal 2003. SFAS No. 150 did not impact our classification of our previously outstanding convertible preferred stock because the convertible preferred stock was not mandatorily redeemable as defined by SFAS No. 150.

SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Intangible Assets," were issued by the FASB in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. Depending on how the accounting and disclosure literature is applied, oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. In addition, the disclosures required by SFAS No. 141 and SFAS No. 142 relative to intangibles would be included in the notes to financial statements. Historically, we, like most other oil and gas companies, have included these oil and natural gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the oil and gas properties, even after SFAS No. 141 and SFAS No. 142 became effective.

Our results of operations and cash flows would not be affected, as these oil and natural gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be accounted for in accordance with full cost accounting rules.

At December 31, 2003 and December 31, 2002, we had leaseholds of approximately $14.9 million and $12.7 million, respectively that would be reclassified from "oil and gas properties" to "intangible leaseholds" on our consolidated balance sheets if we applied the interpretations. These figures represent the costs incurred, net of amortization, since June 30, 2001, the effective date of SFAS No. 141. Amounts prior to June 30, 2001 were not identified since our accounting procedures were not designed to account for leaseholds separately. These classifications would require us to make disclosures set forth under SFAS No. 142 related to these interests.

We will continue to classify our oil and natural gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as tangible oil and gas properties until further guidance is provided.

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."

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. Effective January 1, 2001, we adopted SFAS No. 133. 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, 2002, we had no outstanding derivative financial instruments.

As of December 31, 2003, we had derivative instruments outstanding covering 8.8 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, 2003.

	Expected Maturity, 2004					Fair Value at December 31, 2003
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total	(In thousands)
Swaps:						
Oil						
Volumes (bbl)	83,250	45,500	9,200	9,200	147,150	$ (201)
Weighted average price ($/bbl)	$ 30.59	$ 29.64	$ 28.50	$ 28.50	$ 30.03	
Natural Gas						
Volumes (MMbtu)	2,420,000	910,000	920,000	—	4,250,000	$1,067
Weighted average price ($/MMbtu)	$ 6.71	$ 5.00	$ 4.93	—	$ 5.96	
Collars:						
Natural Gas						
Volumes (MMbtu)	—	910,000	920,000	1,840,000	3,670,000	$ (208)
Weighted average price ($/MMbtu)						
Floor	$ —	$ 4.00	$ 4.34	$ 4.00	$ 4.09	
Cap	$ —	$ 6.81	$ 6.00	$ 7.52	$ 6.96	
3-way collars:						
Natural Gas						
Volumes (MMbtu)	910,000	—	—	—	910,000	$ 31
Weighted average price ($/MMbtu)						
Floor (purchased put option)	$ 4.50	$ —	$ —	$ —	$ 4.50	
Cap 1 (sold call option)	$ 8.50	$ —	$ —	$ —	$ 8.50	
Cap 2 (purchased call option)	$ 9.00	$ —	$ —	$ —	$ 9.00	

The fair value of our derivative instruments was $0.7 million as of December 31, 2003 as compared to none as of December 31, 2002.

In addition to the information set forth in the table above, we will deliver 5.2 Bcfe in 2004, 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 price of $4.05 per Mcfe.

During 2003, we delivered approximately 20% of our production under the Production Payment and amortized deferred revenue at the weighted average realized price of $4.05 per Mcfe and also entered into derivative arrangements designed to reduce price downside risk for approximately 20% of the balance of our production. During 2002, we delivered approximately 30% of our production under the Production Payment sold in February 2001 at a weighted average discounted price of $4.05 per Mcfe and also entered into derivative contracts that covered approximately 17% of the balance of our production.

Commodity Price Swaps. Commodity price swap agreements require us to make or 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.

Interest Rate Risk

We use fixed and variable rate long-term debt to finance our capital spending program and for general corporate purposes. The 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 $125.0 million at 8.9% as of December 31, 2003 and $186.3 million at 9.6% as of December 31, 2002. Our variable rate debt and weighted average interest rate was $17.0 million at 3.6% as of December 31, 2003 and $0.5 million at 5.3% as of December 31, 2002.

The tables below present principal cash flows and related average interest rates by expected maturity date for our debt obligations as of December 31, 2003 and 2002 (dollars in millions).

	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%		
Variable rate	—	—	$ 17.0	$ 17.0	$ 17.0
Average interest rate	—	—	3.605%		

	As of December 31, 2002					
	Expected Maturity Date					
	2003	2004	2005	2006	Total	Fair Value
Long-term debt						
Fixed rate	$ 61.3	—	—	$125.0	$186.3	$155.7
Average interest rate	11.00%	—	—	8.875%		
Variable rate	$ 0.5	—	—	—	$ 0.5	$ 0.5
Average interest rate	5.250%	—	—	—		

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

REPORT OF INDEPENDENT AUDITORS

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, 2003 and 2002 and the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the two years in the period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The consolidated financial statements of KCS Energy, Inc. and subsidiaries as of December 31, 2001, and for the year then ended, were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated March 13, 2002. Their report, however, had an explanatory paragraph indicating that the Company changed its method of accounting for derivative instruments and hedging activities, effective January 1, 2001, to conform with Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities."

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of KCS Energy, Inc. and subsidiaries as of December 31, 2003 and 2002 and the consolidated results of their operations and their cash flows for each of the two years ended December 31, 2003 in conformity with accounting principles generally accepted in the United States.

As discussed above, the consolidated financial statements of KCS Energy, Inc. and subsidiaries as of December 31, 2001, and for the year then ended, were audited by other auditors who have ceased operations. As described in Note 1, 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 1, 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 (SFAS No. 143). These financial statements have been revised to disclose the pro forma effect on income available to common stockholders and earnings per share as if the Company had applied the new amortization method to its oil and gas properties and as if the Company had adopted SFAS No. 143 on January 1, 2001. Our audit procedures with respect to these adjustments in Note 1 for 2001 included (a) agreeing the previously reported income available to common stockholders and basic and diluted earnings per share to the previously issued financial statements, (b) agreeing the adjustments to reported income available to common stockholders, representing changes in the amortization method and changes mandated by SFAS No. 143, to the Company's underlying records obtained from management, and (c) testing the mathematical accuracy of the reconciliation of adjusted income available to common stockholders and the related per-share amounts. With respect to the disclosure of the pro forma liability for asset retirement obligations as of January 1, 2001, included in Note 1, our audit procedures included reviewing the calculation and assumptions used in determining this amount. In our opinion, such adjustments are appropriate and have been properly applied. However, we were not engaged to audit, review, or apply any procedures to the 2001 consolidated financial statements of KCS Energy, Inc. and subsidiaries other than with respect to such adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2001 consolidated financial statements taken as a whole.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 11, 2004

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To KCS Energy, Inc.:

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

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

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

As explained in Note 10 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities to conform with Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities."

/s/ ARTHUR ANDERSEN LLP

Houston, Texas
March 13, 2002

THIS IS A COPY OF AN ACCOUNTANTS' REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP, THE COMPANY'S FORMER INDEPENDENT PUBLIC ACCOUNTANTS, IN CONNECTION WITH THE COMPANY'S FORM 10-K FILED APRIL 1, 2002, AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN SINCE THAT DATE. PLEASE READ EXHIBIT 23.2 FOR FURTHER INFORMATION. THE COMPANY IS INCLUDING THIS COPY OF THE ARTHUR ANDERSEN LLP AUDIT REPORT PURSUANT TO RULE 2-02(e) OF REGULATION S-X UNDER THE SECURITIES ACT OF 1933, AS AMENDED.

KCS ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31,		
	2003	2002	2001
	(Amounts in thousands, except per share data)		
Oil and natural gas revenue	$159,826	$120,002	$174,434
Other, net	5,001	(1,183)	17,557
Total revenue and other	164,827	118,819	191,991
Operating costs and expenses			
Lease operating expenses	26,461	25,246	30,456
Production taxes	8,145	5,589	8,195
General and administrative expenses	8,011	8,255	8,885
Stock compensation	2,715	782	1,419
Bad debt expense	339	215	4,074
Asset retirement obligation accretion	1,116	—	—
Depreciation, depletion and amortization	47,885	49,251	58,314
Total operating costs and expenses	94,672	89,338	111,343
Operating income	70,155	29,481	80,648
Interest and other income	112	279	1,319
Interest expense	(20,970)	(19,945)	(21,799)
Income before reorganization items and income taxes	49,297	9,815	60,168
Reorganization items			
Financial restructuring costs	—	—	(3,175)
Interest income	—	—	227
Reorganization items, net	—	—	(2,948)
Income before income taxes and cumulative effect of accounting change	49,297	9,815	57,220
Federal and state income tax expense (benefit)	(20,229)	13,763	(8,359)
Net income (loss) before cumulative effect of accounting change	69,526	(3,948)	65,579
Cumulative effect of accounting change, net of tax	(934)	(6,166)	—
Net income (loss)	68,592	(10,114)	65,579
Dividends and accretion of issuance costs on preferred stock	(909)	(1,028)	(1,761)
Income (loss) available to common stockholders	$ 67,683	$(11,142)	$ 63,818
Earnings (loss) per share of common stock — basic			
Before cumulative effect of accounting change	$ 1.73	$ (0.14)	$ 2.02
Cumulative effect of accounting change	(0.02)	(0.17)	—
Earnings (loss) per share of common stock — basic	$ 1.71	$ (0.31)	$ 2.02
Earnings (loss) per share of common stock — diluted			
Before cumulative effect of accounting change	$ 1.63	$ (0.14)	$ 1.69
Cumulative effect of accounting change	(0.02)	(0.17)	—
Earnings (loss) per share of common stock — diluted	$ 1.61	$ (0.31)	$ 1.69
Average shares outstanding for computation of earnings (loss) per share			
Basic	39,579	35,834	31,668
Diluted	42,659	35,834	38,828

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

KCS ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(Amounts in thousands, except share and per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,178	$ 6,935
Trade accounts receivable, less allowance for doubtful accounts of $4,896 in 2003 and $4,678 in 2002	23,911	16,863
Prepaid drilling	1,014	1,362
Other current assets	3,706	2,034
Current assets	30,809	27,194
Property, plant and equipment		
Oil and gas properties, full cost method, less accumulated DD&A — 2003 $933,572; 2002 $891,124	283,791	231,579
Other property, plant and equipment, at cost less accumulated depreciation — 2003 $11,598; 2002 $10,415	8,214	8,715
Property, plant and equipment, net	292,005	240,294
Deferred charges and other assets	1,334	645
Deferred taxes	18,818	—
	$ 342,966	$ 268,133
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities		
Accounts payable	$ 27,834	$ 23,854
Accrued interest	5,100	8,174
Accrued drilling cost	9,596	2,861
Other accrued liabilities	9,071	8,784
Current liabilities	51,601	43,673
Deferred credits and other liabilities		
Deferred revenue	38,696	66,582
Asset retirement obligation	11,918	—
Other	720	961
Deferred credits and other liabilities	51,334	67,543
Long-term debt		
Senior notes	—	61,274
Senior subordinated notes	125,000	125,000
Bank credit facility	17,000	500
Long-term debt	142,000	186,774
Commitments and contingencies		
Preferred stock, authorized 5,000,000 shares, issued 30,000 shares redeemable convertible preferred stock, par value $.01 per share liquidation preference $1,000 per share — 13,288 shares outstanding in 2002	—	12,859
Stockholders' equity (deficit)		
Common stock, par value $0.01 per share, authorized 75,000,000 shares; issued 50,532,373 and 38,611,816, respectively	505	386
Additional paid-in capital	236,204	167,335
Accumulated deficit	(128,632)	(196,315)
Unearned compensation	(725)	(880)
Accumulated other comprehensive income	(4,580)	(8,501)
Less treasury stock, 2,167,096 shares, at cost	(4,741)	(4,741)
Stockholders' equity (deficit)	98,031	(42,716)
	$ 342,966	$ 268,133

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 Income	Treasury Stock	Comprehensive Income	(Deficit) Equity
				(Dollars in thousands)				
Balance at December 31, 2000	$314	$145,098	$(248,991)	$ —	$ —	$(4,741)		$(108,320)
Comprehensive income								
Net Income	—	—	65,579	—	—	—	$ 65,579	65,579
Commodity hedges, net of tax	—	—	—	—	(11,162)	—	(11,162)	(11,162)
Comprehensive income							$ 54,417	
Conversion of redeemable preferred stock	46	13,724	—	—	—	—		13,770
Stock issuances — option and benefit plans	6	2,906	—	(2,711)	—	—		201
Stock compensation expense	—	—	—	1,419	—	—		1,419
Dividends and accretion of issuance costs on preferred stock	2	812	(1,761)	—	—	—		(947)
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

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,		
	2003	2002	2001
	(Dollars in thousands)		
Cash flows from operating activities:			
Net income (loss)	$ 68,592	$(10,114)	$ 65,579
Non-cash charges (credits):			
Depreciation, depletion and amortization	47,885	49,251	58,314
Amortization of deferred revenue	(27,886)	(45,182)	(63,089)
Deferred tax expense (benefit)	(20,929)	13,763	(8,359)
Cumulative effect of accounting change, net of tax	934	6,166	—
Asset retirement obligation accretion	1,116	—	—
Non-cash losses on derivative instruments, net	5,512	5,041	8,085
Bad debt expense	339	215	4,074
Stock compensation	2,715	782	1,419
Other non-cash charges and credits, net	3,703	1,650	(233)
Reorganization items	—	—	2,948
Net changes in assets and liabilities:			
Proceeds from Production Payment, net	—	—	174,969
Realized losses on derivative instruments terminated in connection with Plan of reorganization	—	—	(27,995)
Trade accounts receivable	(7,387)	3,264	21,872
Other current assets	(1,672)	562	(1,021)
Accounts payable and accrued liabilities	1,756	(4,122)	(1,042)
Accrued interest	(3,074)	(915)	(49,109)
Other, net	(582)	464	(45)
Net cash provided by operating activities before reorganization items	71,022	20,825	186,367
Reorganization items (excluding non-cash write-off of deferred debt issuance costs)	—	—	(2,948)
Net cash provided by operating activities	71,022	20,825	183,419
Cash flows from investing activities:			
Investment in oil and gas properties	(78,126)	(48,596)	(85,033)
Proceeds from the sale of oil and gas properties	(153)	30,474	5,100
Investment in other property, plant and equipment	(682)	56	(2,159)
Net cash used in investing activities	(78,961)	(18,066)	(82,092)
Cash flows from financing activities:			
Proceeds from borrowings	69,295	500	—
Repayments of debt	(114,069)	(18,526)	(146,905)
Issuance of redeemable convertible preferred stock	—	—	28,412
Proceeds from common stock offering	51,995	—	—
Deferred financing costs and other, net	(4,039)	(725)	99
Net cash proved by (used in) financing activities	3,182	(18,751)	(118,394)
Increase (decrease) in cash and cash equivalents	(4,757)	(15,992)	(17,067)
Cash and cash equivalents at beginning of year	6,935	22,927	39,994
Cash and cash equivalents at end of year	$ 2,178	$ 6,935	$ 22,927

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

KCS ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED 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.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards 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 revenue 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 currently in income. During each period presented, the contracts that were designated as hedges qualified for hedge accounting and continue to qualify for hedge accounting in accordance with SFAS No. 133, as amended.

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 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, KCS changed its accounting for dismantlement, restoration and abandonment costs. Please read "New Accounting Principles." 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 $6.8 million and $3.4 million as of December 31, 2003 and 2002, respectively. The Company will begin to amortize these costs when proved reserves are established or impairment (assessed quarterly) 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. Beginning in 2003, the Company had to determine how to incorporate the asset retirement obligations into the quarterly full-cost ceiling test calculations. SFAS No. 143 is silent with respect to this issue and although there are various views, the Company elected to continue to include the capitalized cost of its asset retirement obligations in the oil and gas property balance and exclude the cash outflow associated with future abandonment cost from future development cost when calculating the pre-tax present value of future net revenues. This results in both a higher ceiling test threshold and a higher net oil and gas property balance. Another widely contemplated view is to include the undiscounted asset retirement obligation as part of future development cost, essentially reducing the pre-tax present value of future net revenues and to net the asset retirement obligation recorded on the balance sheet against the oil and gas property balance. The Company believes that its approach is more conservative although at the present time there is no material difference in the ceiling test calculation using either of these methods.

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 volume sold. The volume of natural gas 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. The Company has a liability of $0.7 million for imbalances as of December 31, 2003 and 2002. 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.

Pursuant to the Production Payment discussed in Note 2, the Company recorded the net proceeds from the sale of the Production Payment of approximately $175.0 million as deferred revenue on the balance sheet. In accordance with SFAS No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies," 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 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 2003, the Company delivered 6.8 Bcfe under this Production Payment and recorded $27.9 million of oil and natural gas revenue. Since the sale of the Production Payment in February 2001 through December 31, 2003, the Company has delivered 33.7 Bcfe, or 78% of the total quantity to be delivered. For 2004, scheduled deliveries under the Production Payment are 5.2 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 4 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 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.

	2003	2002	2001
	(Amounts in thousands except per share data)		
Basic earnings (loss) per share			
Income (loss) available to common stockholders as reported	$67,683	$(11,142)	$63,818
Add: Stock-based compensation expense included in reported net income	2,715	782	1,419
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(1,927)	(1,569)	1,316
Pro forma income (loss) available to common stockholders	$68,471	$(11,929)	$66,553
Average shares outstanding	39,579	35,834	31,668
Earnings (loss) per share:			
Basic — as reported	$ 1.71	$ (0.31)	$ 2.02
Basic — pro forma	$ 1.73	$ (0.33)	$ 2.10
Diluted earnings (loss) per share			
Income (loss) available to common stockholders as reported	$67,683	$(11,142)	$63,818
Dividends and accretion of issuance costs on preferred stock	909	n/a	1,761
Numerator as reported	68,592	(11,142)	65,579
Add: Stock-based compensation expense included in reported net income	2,715	782	1,419
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(1,927)	(1,569)	1,316
Pro forma numerator	$69,380	$(11,929)	$68,314
Average diluted shares outstanding	42,659	35,834	38,828
Earnings (loss) per share:			
Diluted — as reported	$ 1.61	$ (0.31)	$ 1.69
Diluted — pro forma	$ 1.63	$ (0.33)	$ 1.76

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 and $4.7 million as of December 31, 2003 and 2002, respectively. 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.

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:

	2003	2002	2001
	(Amounts in thousands except per share data)		
Basic earnings (loss) per share:			
Income (loss) available to common stockholders	$67,683	$(11,142)	$63,818
Average shares of common stock outstanding	39,579	35,834	31,668
Basic earnings (loss) per share	$ 1.71	$ (0.31)	$ 2.02
Diluted earnings (loss) per share:			
Income (loss) available to common stockholders	$67,683	$(11,142)	$63,818
Dividends and accretion of issuance costs on preferred stock	909	n/a	1,761
Diluted earnings (loss)	$68,592	$(11,142)	$65,579
Average shares of common stock outstanding	39,579	35,834	31,668
Assumed conversion of convertible preferred stock	2,832	n/a	6,808
Dividends on convertible preferred stock	n/a	n/a	232
Stock options and warrants	248	n/a	120
Average diluted shares of common stock outstanding	42,659	35,834	38,828
Diluted earnings (loss) per share	$ 1.61	$ (0.31)	$ 1.69

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.

Common Stock Outstanding

	2003	2002	2001
Balance, beginning of the year	36,444,720	34,677,399	29,265,910
Shares issued for:			
Option and benefit plan, net of forfeited shares	517,272	413,401	660,657
Sale of common shares	6,900,000	—	—
Conversion of redeemable preferred stock	4,429,317	980,664	4,589,990
Dividends on preferred stock paid in common stock	73,968	373,256	160,842
Balance, end of year	48,365,277	36,444,720	34,677,399

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

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. Subsequent to adoption, the effect of the change in accounting principle was a $0.4 million additional non-cash charge against income (or a $0.01 loss per share).

The cumulative effect of change in accounting principle did not take into consideration the potential impacts of adopting SFAS No. 143 on previous full-cost ceiling tests. Management chose not to recalculate historical full-cost ceiling tests upon adoption even though historical oil and gas property balances would have been higher had the Company applied the provisions of this statement. Management believes this approach is appropriate because SFAS No. 143 is silent on this issue and was not effective during previous ceiling test periods. If the Company re-calculated the historical ceiling tests and included the impact as a component of the cumulative effect of adoption, the cumulative loss would have potentially been larger. A ceiling test calculation, however, was performed upon adoption and at the end of each subsequent quarterly reporting period and no ceiling test impairment (writedown) was encountered.

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, 2001.

	2002	2001
	(Amounts in thousands except per share data)	
Income (loss) attributed to common stock:		
As reported	$(11,142)	$63,818
Pro forma	(11,659)	62,122
Earnings (loss) per share		
Basic — as reported	$ (0.31)	$ 2.02
Basic — pro forma	$ (0.33)	$ 1.96
Diluted — as reported	$ (0.31)	$ 1.69
Diluted — pro forma	$ (0.33)	$ 1.65
Pro Forma liability for asset retirement obligation:		
Beginning of year	$ 10,052	$ 8,866
End of year	$ 11,142	$10,052

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, 2003:

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

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. The following table illustrates the effect on income attributable to common stockholders and earnings per share if the Company had applied UOP to amortize its oil and gas properties during 2001.

	2001
	(Amounts in thousands except for per share data)
Income attributed to common stock:	
As reported	$63,818
Pro forma	64,655
Earnings per share	
Basic — as reported	$ 2.02
Basic — pro forma	$ 2.04
Diluted — as reported	$ 1.69
Diluted — pro forma	$ 1.71

The proforma effect on our 2001 results, had both SFAS No. 143 and UOP been adopted, would have been a decrease of $0.9 million to $62.9 million in income attributed to common stock or $0.03 per basic and diluted share.

In January 2003, the Financial Accounting Standards Board, or FASB, issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51," or FIN 46. FIN 46 requires a company to consolidate a variable interest entity, or VIE, if the company has a variable interest (or combination of variable interests) that is exposed to a majority of the entity's expected losses if they occur, receives a majority of the entity's expected residual returns if they occur, or both. In addition, more extensive disclosure requirements apply to the primary and other significant variable interest owners of the VIE. This interpretation applies immediately to VIEs created after January 31, 2003, and to VIEs in which an enterprise obtains an interest after that date. It is also generally effective for the first fiscal year or interim period ending after December 15, 2003, to VIEs in which a company holds a variable interest that is acquired before February 1, 2003. The Company has concluded it does not have any interests in VIEs and that this interpretation has no impact on its consolidated financial statements.

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150 "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," or SFAS No. 150. SFAS No. 150 establishes standards on how a company classifies and measures certain financial instruments with characteristics of both liabilities and equity. The statement requires that the Company classify as liabilities the fair value of all mandatorily redeemable financial instruments that had previously been recorded as equity or elsewhere in the consolidated financial statements. This statement is effective for financial instruments entered into or modified after May 31, 2003, and is otherwise effective for all existing financial instruments beginning in the third quarter of 2003. SFAS No. 150 did not impact the Company's classification of its convertible preferred stock because the convertible preferred stock was not mandatorily redeemable as defined by SFAS No. 150.

Statement of Financial Accounting Standards No. 141, "Business Combinations," or SFAS No. 141, and Statement of Financial Accounting Standards No.142, "Goodwill and Intangible Assets," or SFAS No. 142, were issued by the FASB in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. Depending on how the accounting and disclosure literature is applied, oil and natural gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. In addition, the disclosures required by SFAS No. 141 and SFAS No. 142 relative to intangibles would be included in the notes to financial statements. Historically, KCS, like most other oil and gas companies, has included these oil and natural gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the oil and gas properties, even after SFAS No. 141 and SFAS No. 142 became effective. Disaggregating these costs would not affect the Company's results of operations and cash flows as these oil and natural gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be accounted for in accordance with full cost accounting rules.

At December 31, 2003 and December 31, 2002, we had leaseholds of approximately $14.9 million and $12.7 million, respectively that would be reclassified from "oil and gas properties" to "intangible leaseholds" on our consolidated balance sheets if we applied the interpretations. These figures represent the costs incurred, net of amortization, since June 30, 2001, the effective date of SFAS No. 141. Amounts prior to June 30, 2001 were not identified since the Company's accounting systems were not designed to account for leaseholds separately. These classifications would require us to make disclosures set forth under SFAS No. 142 related to these interests.

We will continue to classify our oil and natural gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as tangible oil and gas properties until further guidance is provided.

2. Reorganization

On January 30, 2001, the United States Bankruptcy Court for the District of Delaware confirmed the Company's plan of reorganization, or the Plan, under Chapter 11 of Title 11 of the United States Bankruptcy Code after the Company's creditors and stockholders voted to approve the Plan. On February 20, 2001, the Company completed the necessary steps for the Plan to go effective and emerged from bankruptcy having reduced its debt from a peak of $425.0 million in early 1999 to $215.0 million. The Company also had cash in excess of $30.0 million.

Under the terms of the Plan, the Company: (1) 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 and repaid all amounts outstanding under its existing bank credit facilities; (2) sold $30.0 million of convertible preferred stock; (3) paid to the holders of the Company's 11% Senior Notes, on a pro rata basis, cash equal to the sum of (a) $60.0 million plus the amount of past due accrued and unpaid interest of $15.1 million on $60.0 million of the Senior Notes as of the effective date, compounded semi-annually at 11% per year, and (b) the amount of past due accrued and unpaid interest of $21.5 million on $90.0 million of the Senior Notes as of January 15, 2001, compounded semi-annually at 11% per year; (4) paid to the holders of the Company's 8⅞% Senior Subordinated Notes, cash in the amount of past due accrued and unpaid interest of $23.7 million as of January 15, 2001, compounded semi-annually at 8⅞% per year; (5) renewed the remaining outstanding $90.0 million principal amount of Senior Notes and $125.0 million principal amount of Senior Subordinated Notes under amended indentures without a change in interest rates; and (6) paid pre-petition trade creditors in full. Stockholders retained 100% of their common stock, subject to dilution from conversion of the newly issued convertible preferred stock.

3. 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 $524,419 in 2003, $531,103 in 2002 and $510,702 in 2001.

4. 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, 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 2003, the Company recorded $1.9 million 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 or 2001 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, 2003, there were 681,404 outstanding shares of restricted stock.

As of December 31, 2003, a total of 1,289,493 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, the cancelled 1992 Stock Plan and the cancelled 1994 Directors' Stock Plan as of December 31, 2003, 2002 and 2001 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 2003: (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%. The weighted average assumptions used for grants in 2001 were: (1) risk-free interest rate of 5.4%; (2) expected dividend yield of 0.00%; (3) expected life of 10 years; and (4) expected stock price volatility of 85.3%.

	2003		2002		2001	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,564,761	$4.73	1,229,043	$5.49	1,378,430	$10.66
Cancelled(a)	—	—	—	—	(1,225,930)	11.75
Granted	527,500	3.54	501,000	2.75	1,237,259	5.49
Exercised	(96,057)	5.17	—	—	(152,500)	1.86
Forfeited	(110,482)	5.02	(165,282)	4.42	(8,216)	5.51
Outstanding at end of year	1,885,722	4.36	1,564,761	4.73	1,229,043	5.49
Exercisable at end of year	868,723	$5.13	494,522	$5.56	6,000	$ 9.61
Weighted average fair value of options granted		$3.07		$2.39		$ 4.52

(a) Cancelled in connection with the Company's plan of reorganization.

The following table summarizes information about stock options outstanding as of December 31, 2003.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2003	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2003	Weighted Average Exercise Price
$1.71-$5.20	679,866	8.53	$2.42	139,134	$2.82
5.21- 6.00	1,200,856	7.62	5.43	724,589	5.55
6.01- 9.61	5,000	7.40	9.61	5,000	9.61
$2.75-$9.61	1,885,722	7.94	$4.36	868,723	$5.13

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 19,394 shares, 8,209 shares and 9,160 shares during 2003, 2002 and 2001, respectively. As of December 31, 2003, there were 756,595 shares available for issuance under the Program.

5. Debt

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

	2003	2002
	(Amounts in thousands)	
Bank Credit Facility	$ 17,000	$ 500
11% Senior Notes	—	61,274
8⅞% Senior Subordinated Notes	125,000	125,000
	142,000	186,774
Classified as short-term debt	—	—
Long-term debt	$142,000	$186,774

Bank Credit Facility

On November 18, 2003, the Company amended and restated its bank credit facility with a group of commercial bank lenders. The bank credit facility, which is used for general corporate purposes, including working capital, and to support the Company's capital expenditure program, provides up to $100 million of revolving borrowing capacity and matures on November 20, 2006, provided that the maturity date will be October 17, 2005 if the Company's 8⅞% Senior Subordinated Notes are not fully refinanced or repaid by October 14, 2005. Borrowing capacity under the bank credit facility is subject to a borrowing base, initially set at $100 million, which 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 the Company's subsidiaries, are pledged to secure the bank credit facility, and each of the Company's subsidiaries have guaranteed the Company's obligations under the bank credit facility.

Borrowings under the bank credit facility bear interest, at the Company's option, at an interest rate of LIBOR plus 2.25% to 3.0% or the greater of (1) the Federal Funds Rate plus 0.5% or (2) the Base Rate, plus 0.5% to 1.25%, depending on utilization. These rates will decrease by 0.5% after the final deliveries are made in connection with the Production Payment discussed in Note 2 to our Consolidated Financial Statements and the lien on the subject properties is released. A commitment fee of 0.5% per year is paid on the unused availability under the bank credit facility. Financing fees pertaining to the bank credit facility as amended in November 2003 are being amortized over the life of the agreement. Deferred financing fees of $2.8 million associated with the facility prior to it being amended and restated in November 2003 and an early termination fee of $0.5 million paid to a previous lender were charged to interest expense during the fourth quarter of 2003.

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 requirements for hedging a portion of the Company's 2004 oil and natural gas production, 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. Financial covenants require us to, among other things: (1) maintain a ratio of Adjusted EBITDA (earnings before interest, taxes, depreciation, depletion, amortization, other non-cash charges and exploration expenses minus amortization of deferred revenue attributable to Production Payment sold in February 2001) to cash interest payments of at least 2.50 to 1.00; (2) maintain a ratio of consolidated current assets to consolidated current liabilities (excluding the current portion of indebtedness for borrowed money and the face amount of letters of credit) of not less than (1) 0.80 to 1.00 until March 31, 2004, (2) 0.90 to 1.00 from April 2004 until September 30, 2004 and (3) 1.00 to 1.00 at all times after September 30, 2004 (any unused portion of the commitment amount of the bank credit facility is deemed to be a current asset of KCS for purposes of this calculation); and (3) not enter into hedging transactions covering more than 80% of projected production from our proved developed producing reserves for the period of such transactions.

The bank credit facility also contains customary events of default, including any defaults by the Company in payment or performance of any other indebtedness equal to or exceeding $5.0 million.

As of December 31, 2003, $17.0 million was outstanding under the bank credit facility, the weighted average interest rate was 3.6% and $82.0 million was available for additional borrowings. We were also in compliance with all covenants under the bank credit facility as of that date.

On January 14, 2003, the Company amended and restated its bank credit facility with a group of institutional lenders which provided up to $90 million of borrowing capacity. Initial proceeds of $69.3 million were used primarily to pay off the Company's maturing Senior Note obligations. This facility was subsequently amended on November 18, 2003 as discussed above.

Senior Notes

On January 25, 1996, the Company issued $150.0 million principal amount of 11% Senior Notes due 2003, or the Senior Notes. The Company redeemed $70.2 million of the Senior Notes during 2001, $18.5 million during 2002 and redeemed the remaining $61.3 million upon maturity on January 15, 2003. The balance as of December 31, 2002 was classified as long-term because of the Company's intent and ability to refinance the outstanding amounts on a long-term basis through the credit facility amended on January 14, 2003.

Senior Subordinated Notes

On January 15, 1998, the Company completed a public offering of $125.0 million of Senior Subordinated Notes at an interest rate of 8⅞%. The Senior Subordinated Notes were non-callable for five years and are unsecured subordinated obligations of the Company. As of January 15, 2004, the Senior Subordinated Notes were callable at 102.96% of the par value and are callable at 101.48% of the par value on January 15, 2005. The Company's subsidiaries have guaranteed the Senior Subordinated Notes on an unsecured subordinated basis. The guarantees by the subsidiaries are full and unconditional and joint and several.

On February 20, 2001, in connection with the Plan, the indenture governing the Senior Subordinated Notes was amended to, among other things, accelerate the maturity date of the Senior Subordinated Notes from January 15, 2008 to January 15, 2006.

The Senior Subordinated Notes, as amended, contain certain restrictive covenants which, among other things, limit the Company's ability to incur additional indebtedness, require the repurchase of the Senior Subordinated Notes upon a change of control and that limit the aggregate cash dividends paid on capital stock, collectively, to 50% of the Company's cumulative net income, as defined in the indenture, during the period beginning after December 31, 2000. The Senior Subordinated Notes also contain cross-default provisions that would result in the acceleration of payments if the Company defaults on its other debt instruments.

Other Information

The estimated fair value of the Company's Senior Subordinated Notes was $130.0 million based on quoted market values at December 31, 2003. The estimated fair value of the Company's Senior Notes and Senior Subordinated Notes at December 31, 2002 were $61.3 million and $94.4 million, respectively.

The scheduled maturities of the Company's outstanding debt during the next five years are as follows: (1) $0 in 2004; (2) $0 in 2005; and (3) $142.0 million in 2006.

Total interest payments were $18.6 million in 2003, $19.2 million in 2002 and $71.5 million in 2001. Interest payments in 2001 included approximately $60.7 million made in connection with the Plan, $60.3 million of which was paid to holders of the Senior Notes and the Senior Subordinated Notes for interest accrued but not paid during the reorganization period, including interest on interest. Capitalized interest was $0.4 million in 2003, $0.7 million in 2002 and $0.6 million in 2001.

6. Shelf Registration Statement/Common Stock Offering

On September 16, 2003, we, along with two of our 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. 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.

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

7. 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 connection with the Plan, 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. The warrants expire on February 29, 2006. In January 2004, one half of the warrants were exercised.

As a result of conversions of the Preferred Stock, 4.4 million, 1.0 million and 4.6 million shares of common stock were issued in 2003, 2002 and 2001, respectively. In addition 0.4 million and 0.2 million shares of common stock were issued as dividends on the preferred stock in 2002 and 2001, respectively.

8. 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) $1.6 million in 2004; (2) $0.8 million in 2005; (3) $0.3 million in 2006; and (4) less than $0.1 million after 2006. Lease payments charged to operating expenses amounted to $1.7 million, $1.3 million and $0.8 million during 2003, 2002 and 2001, respectively. In addition, the Company has unconditional purchase obligations, primarily related to natural gas transportation contracts, of $3.3 million in 2004, $3.0 million in 2005 and $0.7 million in 2006.

9. Income Taxes

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

	For the Year Ended December 31,		
	2003	2002	2001
	(Dollars in thousands)		
Current provision (benefit)	$ 700	$ —	$ —
Deferred provision (benefit), net	(20,929)	12,937	(8,359)
Federal income tax provision (benefit)	(20,229)	12,937	(8,359)
State income tax provision (deferred provision $0 in 2003, $826 in 2002, deferred benefit $600 in 2001)	—	826	—
	$(20,229)	$13,763	$(8,359)
Reconciliation of federal income tax expense (benefit) at statutory rate to provision for income taxes:			
Income before income taxes	$ 49,297	$ 9,815	$57,220
Tax provision at 35% statutory rate	17,254	3,435	20,027
Change in valuation allowance	(37,560)	9,776	(28,401)
State income taxes, net of federal benefit	—	537	—
Other, net	77	15	15
	$(20,229)	$13,763	$(8,359)

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

	December 31,	
	2003	2002
	(Dollars in thousands)	
Income tax effects of:		
Deferred tax assets		
Alternative minimum tax credit carry forwards	$ 3,476	$ 2,776
Net operating loss carry forward	60,671	75,377
Statutory depletion carryforward	400	400
Bad debts	1,714	1,637
Deferred revenue	1,633	—
Other	2,924	1,709
Gross deferred tax asset	70,818	81,899
Valuation allowance	(37,206)	(74,439)
Deferred tax assets	33,612	7,460
Deferred tax liabilities		
Property related items	(14,794)	(5,565)
Deferred revenue	—	(1,895)
Deferred tax liabilities	(14,794)	(7,460)
Net deferred tax asset	$ 18,818	$ —

Federal alternative minimum tax payments, or AMT, of $0.7 million were made during 2003. No federal income tax payments were made during 2002 or 2001. There were no state income tax payments in 2003. State income tax payments were $0.5 million in 2002 and $0.1 million in 2001.

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 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 the Company will generate in the future. Accordingly, while the Company's current net operating loss carryforwards aggregating approximately $173.3 million have remaining lives ranging from 9 to 19 years, with the majority having a life in excess of 15 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 the Company's 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 thereby utilizing a portion of its deferred tax asset and the future outlook for taxable income has improved significantly. Oil and natural gas prices have improved significantly and are expected to remain relatively high for the foreseeable future based on existing available information, including current prices quoted on the New York Mercantile Exchange. Therefore, during 2003, the Company reversed $19 million of the valuation allowance related to expected taxes on future years' taxable income, which is reflected as an income tax benefit in the condensed statements of consolidated operations.

As of December 31, 2003, the Company had tax net operating losses, or NOLs, of approximately $173.3 million available to offset future taxable income, including approximately $11.9 million that will expire in 2012, $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 $27.5 million that will expire in 2022.

10. 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 or 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.

Upon adoption of SFAS No. 133, the Company recorded a liability of $43.8 million representing the fair market value of its derivative instruments at adoption, a related deferred tax asset of $15.3 million and an after-tax cumulative effect of a change in accounting principle of $28.5 million to accumulated other comprehensive income, or OCI. The Company elected not to designate its then-existing derivative instruments as hedges which, subsequent to adoption of SFAS No. 133, would require that changes in a derivative instrument's fair value be recognized currently in earnings. However, SFAS No. 133 requires the Company's derivative instruments that had been designated as cash flow hedges under accounting principles generally accepted prior to the initial application of SFAS No. 133 to continue to be accounted for as cash flow hedges with the transition adjustment reported as a cumulative-effect-type adjustment to accumulated OCI as mentioned above.

In February 2001, the Company terminated certain derivative instruments in connection with its emergence from bankruptcy for a cash payment of $28.0 million, which was offset against the accrued liability recorded in connection with the adoption of SFAS No. 133. During the fiscal quarter ended

March 31, 2001, the ultimate cost to settle the remaining derivative instruments in place as of January 1, 2001 was reduced by $7.7 million as a result of market price decreases. This non-cash gain was recorded in other revenue during the quarter. The actual cost to settle the remaining derivatives was $8.1 million. During 2001, $15.5 million, net of tax, of the $28.5 million charged to OCI was reclassified into earnings. The remaining $4.9 million in accumulated other comprehensive income at December 31, 2003 will be amortized into earnings over the original term of the derivative instruments, which extends through August 2005 ($2.9 million in 2004 and $2.0 million in 2005).

During 2001, all derivative contracts, other than the derivatives terminated in connection with the Company's emergence from bankruptcy as discussed above, were with Enron North America Corp., a subsidiary of Enron Corp. At the end of November 2001, the Company had price swap contracts, designated as hedges, covering 0.3 million MMBtu of December 2001 natural gas production, and price swaps and collars covering 6.2 million MMBtu of 2002 natural gas production. The recorded value of these derivatives at that time was estimated to be $2.7 million. Because of Enron's financial condition, the Company concluded that these derivative contracts no longer qualified for hedge accounting treatment. The Company unwound the December 2001 derivatives and certain swap contracts covering 1.0 million MMBtu of 2002 natural gas production. In December 2001, Enron North America Corp. and Enron Corp. filed for bankruptcy protection and did not pay the Company for the contracts that were unwound. As of December 31, 2001, $2.3 million in unrealized gains related to 2002 natural gas production was included in accumulated OCI and was reclassified into earnings during 2002 as the production relating to those contracts occurred. The related assets were reclassified as a receivable from Enron and a provision for doubtful accounts was established.

As of December 31, 2003, the Company 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 the Company's oil and natural gas hedged position as of December 31, 2003.

	Expected Maturity, 2004					Fair Value at December 31, 2003
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total	(In thousands)
Swaps:						
Oil						
Volumes (bbl)	83,250	45,500	9,200	9,200	147,150	$ (201)
Weighted average price ($/bbl)	$ 30.59	$ 29.64	$ 28.50	$ 28.50	$ 30.03	
Natural Gas						
Volumes (MMbtu)	2,420,000	910,000	920,000	—	4,250,000	$1,067
Weighted average price ($/MMbtu)	$ 6.71	$ 5.00	$ 4.93		$ 5.96	
Collars:						
Natural Gas						
Volumes (MMbtu)	—	910,000	920,000	1,840,000	3,670,000	$ (208)
Weighted average price ($/MMbtu)						
Floor	$ —	$ 4.00	$ 4.34	$ 4.00	$ 4.09	
Cap	$ —	$ 6.81	$ 6.00	$ 7.52	$ 6.96	
3-way collars:						
Natural Gas						
Volumes (MMbtu)	910,000	—	—	—	910,000	$ 31
Weighted average price ($/MMbtu)						
Floor (purchased put option)	$ 4.50	$ —	$ —	$ —	$ 4.50	
Cap 1 (sold call option)	$ 8.50	$ —	$ —	$ —	$ 8.50	
Cap 2 (purchased call option)	$ 9.00	$ —	$ —	$ —	$ 9.00	

The Company realized $6.2 million in net hedging losses during 2003, including $5.5 million net hedging losses due to reclassifications from OCI for contracts terminated prior to January 1, 2003. During 2002, the Company realized $4.9 million in net hedging losses, including $5.0 million net hedging losses due to reclassifications from OCI from contracts terminated prior to January 1, 2002. During 2001, the Company realized $22.1 million in net hedging losses and $8.6 million net non-hedge derivative losses. The table below presents changes in OCI associated with the Company's derivative transactions since adopting SFAS No. 133.

	2003	2002
	(Amounts in thousands)	
Balance, beginning of year	$(8,501)	$(11,162)
Reclassification adjustments of derivatives, net of tax	4,025	2,812
Changes in fair value of hedging positions	(117)	(144)
Ineffective portion of hedges	13	(7)
Balance, end of year	$(4,580)	$ (8,501)

The unrealized loss balances as of the end of year on the Company's derivative transactions are net of income tax benefit of $2.5 million, $4.6 million and $7.0 million for 2003, 2002 and 2001, respectively.

11. Litigation

Medallion California Properties Company, a subsidiary of KCS, or MCPC, was formerly a defendant in a lawsuit filed on January 30, 2001 in the Superior Court, State of California, County of Los Angeles Central District in 2001 by the Newhall Land and Farming Company, or Newhall, against MCPC and certain other parties not affiliated with the Company. The lawsuit alleged environmental contamination and surface restoration on lands in Los Angeles County, California covered by an oil and gas lease owned by MCPC, referred to as the RSF Lease. In addition, Newhall sought a declaration that it was entitled to terminate MCPC's leasehold interest in the lands covered by the RSF Lease, or at least as to those portions of the RSF Lease in which Newhall claimed MCPC was in default under the terms of the lease. The case brought by Newhall was settled effective as of June 30, 2003 and the parties released each other and dismissed their respective claims with prejudice to their refiling. Under the terms of the Settlement Agreement with respect to this case, the RSF Lease was declared to be in full force and effect. Further, MCPC is obligated to conduct certain cleanup and surface restoration activities in accordance with the lease terms on the lands covered by the RSF Lease upon the earlier of abandonment of the lease or the lessor's purchase of the lease, wells and related equipment as the lessor is entitled to do under the terms of the RSF Lease. Also, MCPC must deposit 15% of its net cash flow from the RSF Lease into an escrow account to secure performance of its cleanup and surface restoration obligations. The amount of the account to secure performance is capped at $2.0 million. Upon the timely, satisfactory performance of MCPC's obligations, the $2.0 million will be released from the escrow account and returned to MCPC.

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 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 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.

12. Quarterly Financial Data (Unaudited)

	Quarters			
	First	Second	Third	Fourth
	(Dollars in thousands, except per share data)			
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
2002				
Revenue and other	$28,824	$ 30,277	$30,472	$29,246
Operating income	5,422	7,784	7,830	8,445
Net income (loss)	$(4,908)	$(12,368)	$ 3,813	$ 3,349
Basic earnings (loss) per common share	$ (0.15)	$ (0.36)	$ 0.10	$ 0.09
Diluted earnings (loss) per common share	$ (0.15)	$ (0.36)	$ 0.09	$ 0.08

Effective January 1, 2002, the Company changed its method of amortizing its oil and gas properties from FGR to UOP. Please read Note 1 to Consolidated Financial Statements. The previously reported amounts reflected in quarterly reports on Form 10-Q for the first three quarters of 2002 reflected FGR. These amounts have been recalculated to reflect UOP in the table above. The effect of this change was to decrease the net losses in the first and second quarters by $2.1 million and $0.8 million, respectively, and increase net income by $0.2 million in both the third and fourth quarters.

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. In addition, certain potentially dilutive securities were not included in certain of the quarterly computations of diluted earnings (loss) per common share because to do so would have been anti-dilutive.

13. 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, 2003 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 $5.97, $4.74 and $2.65 per MMBtu, adjusted by lease for Btu content, transportation fees and regional price differentials as of December 31, 2003, 2002 and 2001, respectively. Oil prices were based on West Texas Intermediate, or WTI, posted prices of $29.25, $28.00 and $16.75 as of December 31, 2003, 2002 and 2001, respectively, adjusted by lease for gravity, transportation fees and regional price differentials.

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 2.

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,		
	2003	2002	2001
	(Dollars in thousands)		
Revenue(a)	$ 159,826	$ 120,002	$ 174,434
Production (lifting) costs and taxes	34,606	30,835	38,651
Technical support and other	1,738	3,198	5,049
Depreciation, depletion and amortization(b)	48,908	49,120	58,172
Total expenses	85,252	83,153	101,872
Pretax income from producing activities	74,574	36,849	72,562
Income tax expense (benefit)	(20,229)	13,763	(8,359)
Results of oil and gas producing activities (excluding corporate overhead and interest)	$ 94,803	$ 23,086	$ 80,921
Depreciation, depletion and amortization rate per Mcfe	$ 1.41	$ 1.31	$ 1.25
Capitalized costs incurred:			
Property acquisition	$ (159)	$ 4,822	$ 26,770
Exploration	10,067	12,428	15,321
Development(c)	78,646	30,314	42,942
Total capitalized costs incurred	$ 88,554	$ 47,564	$ 85,033
Capitalized costs at year end:			
Proved properties	$1,210,594	$1,119,339	$1,097,143
Unproved properties	6,769	3,364	8,470
	1,217,363	1,122,703	1,105,613
Less accumulated depreciation, depletion and amortization	(933,572)	(891,124)	(837,096)
Net investment in oil and gas properties	$ 283,791	$ 231,579	$ 268,517

(a) Includes amortization of deferred revenue of $27,886 in 2003, $45,182 in 2002, and $63,089 in 2001 related to volumes delivered under the Production Payment sold in February 2001. See Note 2.

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

(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,		
	2003	2002	2001
	(Dollars in thousands)		
Future cash inflows	$1,556,851	$ 908,031	$ 631,061
Future costs:			
Production	(369,497)	(279,282)	(228,701)
Development(a)	(117,726)	(58,253)	(64,251)
Future income taxes	(229,892)	(49,203)	—
Future net revenues	839,736	521,293	338,109
Discount — 10%	(323,463)	(199,077)	(135,921)
Standardized measure of discounted future net cash flows	$ 516,273	$ 322,216	$ 202,188

Changes in Discounted Future Net Revenues from Proved Reserve Quantities

	For the Year Ended December 31,		
	2003	2002	2001
	(Dollars in thousands)		
Balance, beginning of year	$ 322,216	$202,188	$ 852,608
Increases (decreases)			
Sales, net of production costs	(103,527)	(48,878)	(72,694)
Net change in prices, net of production costs	79,455	135,290	(660,420)
Discoveries and extensions, net of future production and development costs	252,501	66,487	37,865
Changes in estimated future development costs	(2,952)	13,636	7,046
Change due to acquisition of reserves in place	102	11,945	27,591
Development costs incurred during the period	28,978	6,868	10,689
Revisions of quantity estimates	24,916	(38,541)	(14,433)
Accretion of discount	32,222	20,219	85,261
Net change in income taxes	(92,391)	(21,306)	251,871
Sales of reserves in place	(6,450)	(24,842)	(341,223)
Changes in production rates (timing) and other	(18,797)	(850)	18,027
Net increase (decrease)	194,057	120,028	(650,420)
Balance, end of year(b)	$ 516,273	$322,216	$ 202,188

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

(b) Excludes $27,886, $66,582 and $111,880 of deferred revenue at December 31, 2003, 2002 and 2001, respectively, related to the Production Payment sold in 2001 as discussed in Note 2.

Reserve Information (Unaudited)

The reserve estimates and associated revenues for all properties for the years ended December 31, 2003 and 2001 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 developed reserves represent only those reserves expected to be recovered through existing wells using equipment currently in place. Proved undeveloped reserves represent proved reserves expected to be recovered from new wells or from existing wells after material recompletion expenditures. All of the Company's reserves are located within the United States.

	2003		2002		2001	
	Natural Gas MMcf	Oil Mbbl	Natural Gas MMcf	Oil Mbbl	Natural Gas MMcf	Oil Mbbl
Proved developed and undeveloped reserves						
Balance, beginning of year	154,993	6,772	190,141	6,644	211,628	8,986
Production(a)	(22,102)	(972)	(19,733)	(1,082)	(23,133)	(1,273)
Discoveries, extensions, etc.	89,691	681	25,777	1,043	35,250	725
Acquisition of reserves in place	49	—	6,253	161	18,382	140
Sales of reserves in place(b)	(1,963)	(293)	(21,406)	(879)	(41,759)	(1,064)
Revisions of estimates	7,450	507	(26,039)	885	(10,227)	(870)
Balance, end of year	228,118	6,695	154,993	6,772	190,141	6,644
Proved developed reserves						
Balance, beginning of year	124,451	5,653	139,137	5,915	173,995	7,885
Balance, end of year	164,787	5,685	124,451	5,653	139,137	5,915

(a) Excludes volumes produced and delivered with respect to the Production Payment sold in February 2001 as discussed in Note 2.

(b) The Company sold a Production Payment in 2001 as discussed in Note 2. The approximate 38.3 Bcf of natural gas and 797,000 barrels of oil Production Payment is reflected as sales of reserves in place in 2001 in the table above. In 2002, the Company sold certain non-core properties.

Approximately 26% of the Company's reserves were classified as proved undeveloped. Furthermore, approximately 14% 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 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.

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

By unanimous written consent dated July 1, 2002, our board of directors, upon the recommendation of its audit committee, approved the dismissal of Arthur Andersen LLP, or Andersen, and the appointment of Ernst & Young LLP to serve as our independent public accountants for the fiscal year ending December 31, 2002.

The audit reports of Andersen with respect to our consolidated financial statements as of and for the fiscal years ended December 31, 2001 and December 31, 2000 did not contain any adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty or audit scope. In addition, there were no modifications as to accounting principles except that the most recent audit report of Andersen dated March 13, 2002 contained an explanatory paragraph with respect to the change in the method of accounting for derivative instruments effective January 1, 2001 as required by the Financial Accounting Standards Board.

During the fiscal year ended December 31, 2001 and the subsequent interim period through July 1, 2002, there were no disagreements with Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure which, if not resolved to Andersen's satisfaction, would have caused them to make reference to the subject matter in connection with their report on our financial statements for those years, and there were no reportable events as defined in Item 304(a)(1)(v) of Regulation S-K.

We provided Andersen with a copy of the above disclosures and requested that Andersen furnish us with a letter addressed to the Securities and Exchange Commission stating whether or not Andersen agreed with the statements made by us and, if not, stating the respects in which it does not agree. We were informed by Andersen's national office that Andersen could not issue such a letter due to the discontinuance of its audit practice.

During our fiscal year ended December 31, 2001 and the subsequent interim period through July 1, 2002, we did not consult Ernst & Young LLP with respect to the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on our consolidated financial statements, or any other matters or reportable events described in Items 304(a)(2)(i) and (ii) of Regulation S-K.

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 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.

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.

PART III

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

Information concerning our officers and directors is set forth in the sections entitled "Election of Directors" and "Executive Officers" of our Proxy Statement for the 2004 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 2004 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 2004 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 is filed as Exhibit 14.1 to this annual report on Form 10-K. 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 located at *www.kcsenergy.com.*

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

Information for this item is set forth in the sections entitled "Executive Compensation," "Report of the Compensation Committee of the Board of Directors on Executive Compensation," "Compensation Committee Interlocks and Insider Participation," "Employment Agreements, Change in Control Agreements and Retention Agreements," "Compensation of Directors" and "Performance Graph" in our Proxy Statement for the 2004 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.***

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 2004 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 2004 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 Public Accountants" in our Proxy Statement for the 2004 Annual Meeting of Stockholders, which section is incorporated in this annual report on Form 10-K by reference.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K.***

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

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

(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 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	Certificate of Designation, Preferences, Rights and Limitations of Series A Convertible Preferred Stock of KCS Energy, Inc. (incorporated by reference to Exhibit (3)ii to Form 10-K (File No. 001-13781) filed with the SEC on April 2, 2001).
3.3	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).
3.4	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 January 15, 1998 between KCS Energy, Inc., certain of its subsidiaries and State Street Bank and Trust Company and First Supplemental Indenture dated February 20, 2001 (incorporated by reference to Exhibit (4)v to Form 10-K (File No. 001-13781) filed with the SEC on April 2, 2001).
4.3	Form of 8⅞% Senior Subordinated Note due 2006 (included in Exhibit 4.2).
4.4	Form of Series A Convertible Preferred Stock Certificate, $0.01 Par Value (incorporated by reference to Exhibit (4)vii to Form 10-K (File No. 001-13781) filed with the SEC on April 2, 2001).
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).*

Exhibit No.	Description
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).*
10.4	KCS Energy, Inc. Savings and Investment Plan and related Adoption Agreement and Summary Plan Description.*†
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.†
10.8	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).*
10.9	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).*
10.10	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).*
10.11	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).*
10.12	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).*
12.1	Statement regarding Computation of Ratios.†
14.1	Code of Ethics.†
21.1	Subsidiaries of KCS Energy, Inc.†
23.1	Consent of Netherland, Sewell and Associates, Inc.†
23.2	Notice Regarding Consent of Arthur Andersen LLP.†
23.3	Consent of Ernst & Young LLP.†
31.1	Certification of James W. Christmas, Chairman and Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.†
31.2	Certification of Joseph T. Leary, Vice President and Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.†

Exhibit No.	Description
32.1	Certification of James W. Christmas, Chairman and Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.†
32.2	Certification of Joseph T. Leary, Vice President and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.†

* Management contract or compensatory plan or arrangement.

† Filed herewith.

(b) *Reports on Form 8-K.*

On October 2, 2003, we filed a report on Form 8-K under Item 5, Other Events, reporting the issuance of a press release announcing continued production increases in two significant fields and an increase in our capital expenditure budget for 2003.

On October 29, 2003, we filed a report on Form 8-K under Item 5, Other Events, reporting the issuance of a press release announcing the results of recent drilling activity.

On November 6, 2003, we filed a report on Form 8-K under Item 5, Other Events, reporting the issuance of a press release announcing our plans to sell 6,000,000 shares of common stock pursuant to an effective shelf registration statement on Form S-3. The report on Form 8-K also furnished information under Item 9, Regulation FD Disclosure, regarding anticipated prospectus supplement disclosure regarding the use of proceeds of the proposed offering and that we were currently negotiating a refinancing of our existing bank credit facility.

On November 7, 2003, we furnished a report on Form 8-K under Item 9, Regulation FD Disclosure, disclosing certain information to be presented to analysts and investors in connection with a common stock offering.

On November 7, 2003, we furnished a report on Form 8-K under Item 12, Results of Operations and Financial Condition, reporting the issuance of a press release announcing financial and operating results for the three and nine months ended September 30, 2003.

On November 19, 2003, we filed a report on Form 8-K under Item 5, Other Events, announcing that we had amended and restated our bank credit facility. The report on Form 8-K also furnished information pursuant to Item 9, Regulation FD Disclosure, announcing the issuance of a press release regarding the amended and restated bank credit facility.

On November 21, 2003, we filed a report on Form 8-K under Item 5, Other Events, announcing the execution of an Underwriting Agreement for the sale of 6,000,000 shares of common stock. The report on Form 8-K also furnished information pursuant to Item 9, Regulation FD Disclosure, regarding the pricing of the common stock offering.

On November 26, 2003, we furnished a report on Form 8-K under Item 9, Regulation FD Disclosure, announcing that we closed a previously announced sale of 6,000,000 shares of common stock.

On December 29, 2003, we filed a report on Form 8-K under Item 5, Other Events, reporting the issuance of a press release announcing an increase in our 2004 capital expenditure budget.

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, 2004

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, 2004
/s/ WILLIAM N. HAHNE William N Hahne	President, Chief Operating Officer and Director	March 15, 2004
/s/ JOSEPH T. LEARY Joseph T. Leary	Vice President and Chief Financial Officer (Principal Financial Officer)	March 15, 2004
/s/ FREDERICK DWYER Frederick Dwyer	Vice President, Controller and Secretary (Principal Accounting Officer)	March 15, 2004
/s/ JAMES L. BOWLES James L. Bowles	Director	March 15, 2004
/s/ G. STANTON GEARY G. Stanton Geary	Director	March 15, 2004
/s/ ROBERT G. RAYNOLDS Robert G. Raynolds	Director	March 15, 2004
/s/ JOEL D. SIEGEL Joel D. Siegel	Director	March 15, 2004
/s/ CHRISTOPHER A. VIGGIANO Christopher A. Viggiano	Director	March 15, 2004

Corporate Directory

Principal Operating Officers

CLIFF S. FOSS, JR.
Senior Vice President, Gulf Coast Division

S. WESLEY VANNATTA
Vice President, Gulf Coast Engineering & Operations

DAVID E. CHANDLER
Vice President, Operations Controller

H. WELDON HOLCOMBE
Vice President, Mid-Continent Engineering & Operations

D. BRAD MAGILL
Vice President, Mid-Continent Exploration

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

Corporate Office

KCS Energy, Inc.
5555 San Felipe
Suite 1200
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) 964-9463

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
(908) 272-8511

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	$ 6.77
2002		**Jan. - Mar.**	**Apr. - June**	**July - Sept.**	**Oct. - Dec.**
Market Price	High	$3.32	$4.01	$2.70	$2.25
	Low	$1.63	$1.75	$1.14	$1.15

Cover photo courtesy of Smith Bits

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