CHESAPEAKE ENERGY CORP
Form 10-K/A
September 18, 2003
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

x **Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the Fiscal Year Ended December 31, 2002

¨ **Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

Oklahoma **(State or other jurisdiction of incorporation or organization)**	**73-1395733** **(I.R.S. Employer Identification No.)**
6100 North Western Avenue **Oklahoma City, Oklahoma** **(Address of principal executive offices)**	**73118** **(Zip Code)**

(405) 848-8000

Registrant s telephone number, including area code

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $.01	New York Stock Exchange
7.875% Senior Notes due 2004	New York Stock Exchange
8.375% Senior Notes due 2008	New York Stock Exchange
8.125% Senior Notes due 2011	New York Stock Exchange
8.5% Senior Notes due 2012	New York Stock Exchange
6.75% Cumulative Convertible Preferred Stock	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 x 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 Exchange Act Rule 12b-2). YES x NO ¨

The aggregate market value of our common stock held by non-affiliates on June 30, 2002 was $1,054,315,346. At February 24, 2003, there were 190,782,300 shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our definitive proxy statement for the 2003

annual meeting of shareholders are incorporated by reference in Part III

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AMENDMENT NO. 1

EXPLANATORY NOTE

As described in Note 16 to the Consolidated Financial Statements, Chesapeake Energy Corporation has revised its previously reported Consolidated Statements of Operations and has made the corresponding revisions to the Notes to Consolidated Financial Statements for the years ended December 31, 2002 and 2001. The revisions had no effect on previously reported net income or net income per share.

Corresponding changes resulting from these revisions of classifications in the financial statements were also made to Item 1. Business , Item 6. Selected Financial Data , Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data .

In light of the refiling of this report for the purpose of revising the financial statements, we have also revised other disclosures from the original filing in response to comments of the staff of the Securities and Exchange Commission.

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PART I

ITEM 1. ***Business***

General

We are one of the ten largest independent natural gas producers in the United States in terms of natural gas produced. Chesapeake began operations in 1989 and completed its initial public offering in 1993. Our common stock trades on the New York Stock Exchange under the symbol CHK. Our principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118, and our main telephone number at that location is (405) 848-8000. We make available free of charge on our website at *www.chkenergy.com*, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

At the end of 2002, we owned interests in approximately 10,700 producing oil and gas wells. Our primary operating area is the Mid-Continent region of the United States, which includes Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle. Other operating areas include the Deep Giddings field in Texas, a portion of the Permian Basin region of southeastern New Mexico and a portion of the Williston Basin located in eastern Montana and western North Dakota. The following table highlights our growth since 1997:

	Years Ended December 31,					
	2002	2001	2000	1999	1998	1997
Production (mmcfe)	181,478	161,451	134,179	133,492	130,277	80,302
Proved reserves (mmcfe)	2,205,125	1,779,946	1,354,813	1,205,595	1,091,348	448,474
Net income (loss) ($ in 000 s)	$ 40,286	$ 217,406	$ 455,570	$ 33,266	$ (933,854)	$ (233,429)

Recent Developments

On January 31, 2003, we completed the acquisition of Mid-Continent gas assets from a wholly-owned subsidiary of Tulsa-based ONEOK, Inc. for $300 million. Based on internal reservoir engineering estimates, we believe the acquisition adds approximately 200 bcfe of proved reserves. The acquisition was funded with proceeds generated from the company s December 2002 issuance of 23 million common shares at $7.50 per share and $150 million of 7.75% senior notes.

In September 2002, we announced our intention to dispose of our assets in the Permian Basin, either by a cash sale or an exchange of Mid-Continent properties. We have decided not to divest the Permian Basin assets as a result of recent favorable drilling results and higher oil and gas prices.

On February 24, 2003, we announced that we had entered into an agreement to acquire El Paso Corporation s Anadarko Basin assets in western Oklahoma and the Texas Panhandle for $500 million, which, by our internal estimates, will add approximately 328 bcfe to our estimated proved reserves and approximately 67 mmcfe to our daily production. We expect to close the El Paso acquisition in March 2003. However, there is no assurance that this acquisition will be completed or that our estimates of the reserves being acquired will prove correct.

On February 24, 2003, we announced that we had entered into an agreement to acquire Vintage Petroleum, Inc. s assets in the Bray field in southern Oklahoma for $30 million, which, by our internal estimates, will add approximately 22 bcfe to our estimated proved reserves and approximately 3.5 mmcfe to our daily production. We expect to close the Vintage acquisition in March 2003. However, there is no assurance that this acquisition will be completed or that our estimates of the reserves being acquired will prove correct.

On February 25, 2003, we announced a proposed private placement of $300 million in aggregate principal amount of senior notes, a proposed public offering of 20,000,000 shares of common stock pursuant to our existing shelf registration statement and a proposed private placement of $200 million of convertible preferred stock. There is no assurance these proposed offerings will be completed or, if they are completed, that they will be completed for the amount contemplated.

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Business Strategy

From our inception in 1989, our business goal has been to create value for our investors by building one of the largest onshore natural gas resource bases in the United States. Since 1998, our business strategy to achieve this goal has been to integrate our aggressive and technologically advanced Mid-Continent drilling program with a Mid-Continent focused producing property consolidation program. We believe this balanced business strategy enables us to achieve greater economies of scale, increase our undrilled acreage inventory and attract and retain talented and motivated land, geoscientific and engineering personnel. We are executing our strategy by:

Consistently Making High-Quality Acquisitions. Our acquisition program is focused on small to medium-sized acquisitions of Mid-Continent natural gas properties that provide high-quality production and significant drilling opportunities. Since January 1, 2000, we have acquired or have signed agreements to acquire $1.9 billion of such properties (primarily in 17 separate transactions of greater than $10 million each) at an estimated average cost of $1.23 per mcfe of proved reserves. Each of these acquisitions either increased our ownership in existing wells or fields or added additional drilling locations in our core Mid-Continent operating area. We believe we are acquiring high-quality assets from El Paso and Vintage, distinguished by proved reserves that are 96% gas and 70% proved developed. We believe these properties provide substantial opportunities for additional drilling and improvement of operational efficiencies. The El Paso and Vintage properties complement our existing Mid-Continent assets, with 96% and 88%, respectively, of their proved reserves located in townships where we presently own properties. Because the Mid-Continent region contains many small companies seeking market liquidity and larger companies seeking to divest non-core assets, we expect to find additional attractive acquisition opportunities in the future.

Consistently Growing through the Drillbit. One of our most distinctive characteristics is our ability to increase reserves through the drillbit. We are conducting one of the five most active drilling programs in the United States with our program focused on finding gas in the Mid-Continent region. We currently have 31 rigs drilling on Chesapeake-operated prospects, and we are participating in approximately 50 wells being drilled by others. Our Mid-Continent drilling program is the most active in the region and is supported by our ownership of an extensive land and 3-D seismic base.

Consistently Focusing on the Mid-Continent. In this region, we believe we are the largest natural gas producer in terms of natural gas produced, the most active driller and the most active acquirer of undeveloped leases and producing properties. We believe the Mid-Continent region, which trails only the Gulf Coast and Rocky Mountain basins in U.S. gas production, has many attractive characteristics. These characteristics include long-lived natural gas properties with relatively predictable decline curves; multi-pay geological targets that decrease drilling risk, resulting in our historical Mid-Continent drilling success rate of over 95%; relatively high natural gas prices, typically only 10 to 20 cents per mmbtu behind Henry Hub index prices; generally lower service costs than in more competitive or more remote basins; and a favorable regulatory environment with virtually no federal land ownership. In addition, we believe the location of our headquarters in Oklahoma City provides us with many competitive advantages over other companies that direct their activities in this region from district offices in Oklahoma City or Tulsa or from out-of-state headquarters.

Consistently Focusing on Low Costs. By minimizing operating costs, we have been able to deliver consistently attractive financial returns through all phases of the commodity price cycle. We believe our general and administrative costs and our lease operating expenses are among the lowest in the industry. We believe these low costs are the result of our management s effective cost-control programs, our high-quality asset base and the extensive and competitive services, gas processing and transportation infrastructures in the Mid-Continent. We believe the ONEOK, El Paso and Vintage acquisitions should reduce our overall operating cost structure per mcfe because our production costs per mcfe for these properties are expected to be lower than our current production costs per mcfe. We believe further operating efficiencies can be achieved through our acquisition of these properties.

Consistently Improving our Capitalization. We have made significant progress in improving our balance sheet since the beginning of 1999. We have increased our stockholders equity by $1.2 billion through a combination of earnings and common and preferred equity issuances. As of December 31, 1999, our debt to total capitalization ratio was 129%. As of December 31, 2002, this ratio was 65%. We plan to continue making the reduction of the debt to total capitalization ratio one of our primary financial goals.

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Based on our view that natural gas has become the fuel of choice to meet growing power demand and increasing environmental concerns in the United States, we believe our Mid-Continent focused natural gas development strategy should provide substantial growth opportunities in the years ahead. Although U.S. gas production has declined in each of the past six quarters, we have increased our production in each of those quarters. Our goal is to increase our overall production by 10% to 15% per year, with approximately one-third of this growth projected to be generated through the drillbit and the remainder from acquisitions.

Company Strengths

We believe the following six characteristics distinguish our past performance and future growth potential from other natural gas producers:

High-Quality Asset Base. Our producing properties are characterized by long-lived reserves, established production profiles and an emphasis on natural gas. Based upon current production and reserve levels (and pro forma for the El Paso and Vintage acquisitions), our proved reserves-to-production ratio, or reserve life, is approximately 11.8 years. We estimate the El Paso properties have a reserve life of approximately 13 years and the Vintage properties approximately 17 years. In each of our operating areas, our properties are concentrated in locations that enable us to establish substantial economies of scale in drilling and production operations and facilitate the application of more effective reservoir management practices. We intend to continue building our Mid-Continent asset base by concentrating both our drilling and acquisition efforts in this region.

Low-Cost Producer. Our high-quality asset base has enabled us to achieve a low operating cost structure. During 2002, our cash operating costs per unit of production were $0.81 per mcfe, which consisted of general and administrative expenses of $0.10 per mcfe, production expenses of $0.54 per mcfe and production taxes of $0.17 per mcfe. We believe this is one of the lowest operating cost structures among publicly traded independent oil and natural gas producers. We believe the El Paso and Vintage acquisitions should lower our cash operating costs because we project these properties will have production expenses of approximately $0.25 per mcfe. In addition, we believe the El Paso and Vintage acquisitions will lower our overall general and administrative expenses because we expect overhead recovery fees from third parties to more than offset any additional general and administrative expenses associated with managing the acquired assets. We currently operate approximately 77% of our proved reserves. This large percentage of operational control provides us with a high degree of operating flexibility and cost control. The El Paso and Vintage acquisitions will add 660 additional operated wells and will increase our ownership in 174 wells we presently operate.

Successful Acquisition Program. Our experienced asset acquisition team focuses on adding to our attractive resource base in the Mid-Continent region. This area is characterized by long-lived natural gas reserves, low lifting costs, multiple geological targets that provide substantial drilling potential, favorable basis differentials to benchmark commodity prices, a well-developed oil and gas transportation infrastructure and considerable potential for further consolidation of assets. Since 1998 and following the completion of the El Paso and Vintage acquisitions, we will have completed $2.7 billion in acquisitions at an average cost of $1.12 per mcfe of proved reserves. We believe we are well-positioned to continue this consolidation as a result of our large existing asset base, our corporate presence in Oklahoma, our knowledge and expertise in the Mid-Continent region and current trends in the industry. We believe the El Paso and Vintage acquisitions are examples of the application of our acquisition strategy. These properties have a large percentage of proved developed gas reserves with low operating costs, significant operating and undeveloped drilling upside and are located in areas where currently we have a substantial operating presence. We plan to pursue acquisitions of properties with similar characteristics in the future.

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Large Inventory of Drilling Projects. During the past 14 years, we believe we have been one of the ten most active drillers in the United States and the most active driller in the Mid-Continent. We believe we have developed a particular expertise in drilling deep vertical and horizontal wells in search of large natural gas accumulations in challenging reservoir conditions. We actively pursue deep drilling targets because of our view that most undiscovered gas reserves in the Mid-Continent will be found at depths below 12,500 feet. In addition, we believe that our large 3-D seismic inventory, much of which is proprietary to Chesapeake, provides us with an advantage over our competitors, which largely prefer to drill shallower development wells. As a result of our aggressive land acquisition strategies and Oklahoma s favorable forced-pooling regulations, we have been able to accumulate an onshore leasehold position of approximately 2.0 million net acres as of December 31, 2002. In addition, our technical teams have identified over 1,500 exploratory and developmental drillsites, representing more than five years of future drilling opportunities at our current rate of drilling. The El Paso and Vintage acquisitions will add to our existing land inventory and we have identified more than 300 additional potential drillsites associated with the properties to be acquired in these pending acquisitions.

Hedging Program. We have historically used and intend to continue using hedging programs to reduce the risks inherent in producing oil and natural gas, commodities that are extremely volatile in price. We believe this volatility is likely to continue and may even accelerate in the years ahead. We believe that a producer can use this volatility to its benefit by taking advantage of prices when they exceed historical norms. Over the past two years, we increased our oil and gas revenues by $201 million through net realized gains from oil and gas derivatives. We currently have gas hedging positions covering 116 bcf for 2003 at an average price of $4.70 per mcf. In addition, we have 90% of our projected oil production hedged for 2003 at an average NYMEX price of $27.78 per barrel of oil.

Entrepreneurial Management. Our management team formed Chesapeake in 1989 with an initial capitalization of $50,000. Through the following years, this management team has guided our company through operational challenges and extremes of oil and gas prices to create one of the ten largest independent natural gas producers in the United States. The company s co-founders, Aubrey K. McClendon and Tom L. Ward, have been business partners in the oil and gas industry for 20 years and beneficially own approximately 11.1 million and 12.5 million of our common shares, respectively.

Drilling Activity

The following table sets forth the wells we drilled during the periods indicated. In the table, gross refers to the total wells in which we had a working interest and net refers to gross wells multiplied by our working interest.

	Years Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
United States						
Development:						
Productive	617	237.7	423	196.9	291	142.7
Non-productive	34	11.5	36	12.2	12	5.3
Total	651	249.2	459	209.1	303	148.0
Exploratory:						
Productive	47	24.6	36	18.4	32	17.0
Non-productive	10	5.4	17	9.0	11	5.4

Total	57	30.0	53	27.4	43	22.4
Canada(1)						
Development:						
Productive			17	7.6	12	6.1
Non-productive			1	0.4	2	0.8
Total			18	8.0	14	6.9

(1) The company sold all of its Canadian operations in October 2001.

At December 31, 2002, we had 53 (22.4 net) wells in process. We have a fleet of six rigs which are dedicated to drilling wells operated by Chesapeake. Our drilling business is conducted through our wholly owned subsidiary, Nomac Drilling Corporation.

Well Data

At December 31, 2002, we had interests in approximately 10,700 (4,250 net) producing wells, including properties in which we held an overriding royalty interest, of which 350 (200 net) were classified as primarily oil producing wells and 10,350 (4,050 net) were classified as primarily gas producing wells. Chesapeake operates approximately 4,600 of the total 10,700 producing wells. We operate approximately 77% of our proved reserves by volume.

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Production, Sales, Prices and Expenses

The following table sets forth information regarding the production volumes, oil and gas sales, average sales prices received and expenses for the periods indicated:

	Years Ended December 31,								
	2002			2001			2000		
	U.S.	Canada	Combined	U.S.	Canada	Combined	U.S.	Canada	Combined
Net Production:									
Oil (mbbl)	3,466		3,466	2,880		2,880	3,068		3,068
Gas (mmcf)	160,682		160,682	135,096	9,075	144,171	103,694	12,077	115,771
Gas equivalent (mmcfe)	181,478		181,478	152,376	9,075	161,451	122,102	12,077	134,179
Oil and Gas Sales ($ in thousands):									
Oil sales	$ 88,495	$	$ 88,495	$ 69,602	$	$ 69,602	$ 89,209	$	$ 89,209
Oil derivatives realized gains (losses)	(1,092)		(1,092)	7,920		7,920	(8,256)		(8,256)
Oil derivatives unrealized gains (losses)	(7,369)		(7,369)	5,116		5,116			
Total oil sales	$ 80,034	$	$ 80,034	$ 82,638	$	$ 82,638	$ 80,953	$	$ 80,953
Gas sales	$ 470,913	$	$ 470,913	$ 528,608	$ 31,928	$ 560,536	$ 377,695	$ 33,826	$ 411,521
Gas derivatives realized gains (losses)	97,138		97,138	97,471		97,471	(22,304)		(22,304)
Gas derivatives unrealized gains (losses)	(79,898)		(79,898)	79,673		79,673			
Total gas sales	$ 488,153	$	$ 488,153	$ 705,752	$ 31,928	$ 737,680	$ 355,391	$ 33,826	$ 389,217
Total oil and gas sales	$ 568,187	$	$ 568,187	$ 788,390	$ 31,928	$ 820,318	$ 436,344	$ 33,826	$ 470,170
Average Sales Price (excluding gains (losses) on derivatives):									
Oil ($ per bbl)	$ 25.53	$	$ 25.53	$ 24.17	$	$ 24.17	$ 29.08	$	$ 29.08
Gas ($ per mcf)	$ 2.93	$	$ 2.93	$ 3.91	$ 3.52	$ 3.89	$ 3.64	$ 2.80	$ 3.55
Gas equivalent ($ per mcfe)	$ 3.08	$	$ 3.08	$ 3.93	$ 3.52	$ 3.90	$ 3.82	$ 2.80	$ 3.73
Average Sales Price (including realized gains (losses) on derivatives):									
Oil ($ per bbl)	$ 25.22	$	$ 25.22	$ 26.92	$	$ 26.92	$ 26.39	$	$ 26.39
Gas ($ per mcf)	$ 3.54	$	$ 3.54	$ 4.63	$ 3.52	$ 4.56	$ 3.43	$ 2.80	$ 3.36
Gas equivalent ($ per mcfe)	$ 3.61	$	$ 3.61	$ 4.62	$ 3.52	$ 4.56	$ 3.57	$ 2.80	$ 3.50
Expenses ($ per mcfe):									
Production expenses	$ 0.54	$	$ 0.54	$ 0.48	$ 0.26	$ 0.47	$ 0.38	$ 0.32	$ 0.37
Production taxes	$ 0.17	$	$ 0.17	$ 0.22	$	$ 0.20	$ 0.20	$	$ 0.19
General and administrative	$ 0.10	$	$ 0.10	$ 0.09	$ 0.11	$ 0.09	$ 0.09	$ 0.17	$ 0.10
Depreciation, depletion and amortization	$ 1.22	$	$ 1.22	$ 1.08	$ 0.90	$ 1.07	$ 0.76	$ 0.71	$ 0.75

In October 2001, we sold our Canadian subsidiary for approximately $143.0 million.

Proved Reserves

The following table sets forth our estimated proved reserves and the present value of the proved reserves (based on our weighted average wellhead prices at December 31, 2002 of $30.18 per barrel of oil and $4.28 per mcf of gas). These prices were based on the cash spot prices for oil and natural gas at December 31, 2002.

	Oil (mbbl)	Gas (mmcf)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value ($ in thousands)
Mid-Continent	21,262	1,775,128	1,902,702	86%	$ 3,189,592
Gulf Coast	4,006	117,786	141,819	6%	281,749
Permian Basin	7,191	69,518	112,663	5%	180,689
Williston Basin	5,122	6,841	37,576	2%	61,136
Other areas	6	10,328	10,365	1%	4,479
Total	37,587	1,979,601	2,205,125	100%	$ 3,717,645(a)

(a) The standardized measure of discounted future net cash flows at December 31, 2002 was $2,833,918,000.

As of December 31, 2002, the present value of our proved developed reserves as a percentage of total proved reserves was 77%, and the volume of our proved developed reserves as a percentage of total proved reserves was 74%. Natural gas reserves accounted for 90% of total proved reserves at December 31, 2002.

Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate. A change in price of $0.10 per mcf for natural gas and $1.00 per barrel for oil would result in a change in our December 31, 2002 present value of proved reserves of approximately $99 million and $19 million, respectively.

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Development, Exploration, Acquisition and Divestiture Activities

The following table sets forth historical cost information regarding our development, exploration, acquisition and divestiture activities during the periods indicated:

	Years Ended December 31,		
	2002	2001	2000
	($ in thousands)		
Development and leasehold costs (a)	$ 296,426	$ 346,114	$ 148,608
Exploration costs	89,422	47,945	24,658
Acquisition costs:			
Proved properties	316,583	669,201	75,285
Unproved properties	14,000	35,132	3,625
Deferred income taxes	62,398	36,309	
Sales of oil and gas properties	(839)	(151,444)	(1,529)
Capitalized internal costs	16,981	12,914	10,194
Total	$ 794,971	$ 996,171	$ 260,841

(a) Includes $120 million, $121 million and $54 million of expenditures in 2002, 2001 and 2000, respectively, related to properties carried as proved undeveloped locations in the prior year s reserve reports. Included in our reserve report as of December 31, 2002 are estimated future development costs of $570 million related to the development of proved undeveloped reserves ($248 million in 2003, $203 million in 2004 and $119 million in 2005). Historically and in the future Chesapeake s development drilling schedules are subject to revision and reprioritization throughout the year, resulting from unknowable factors such as the success in one developmental drilling prospect leading to an additional drilling opportunity, rig availability, title issues or delays, and the effect that acquisitions may have on prioritizing development drilling plans.

Acreage

The following table sets forth as of December 31, 2002 the gross and net acres of both developed and undeveloped oil and gas leases which we hold. Gross acres are the total number of acres in which we own a working interest. Net acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our options to acquire additional leasehold which have not been exercised.

	Developed		Undeveloped		Total Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	2,569,352	1,228,365	601,993	312,513	3,171,345	1,540,878
Gulf Coast	246,508	146,986	132,909	106,826	379,417	253,812
Permian Basin	66,134	50,144	77,602	48,024	143,736	98,168

Williston Basin	40,891	16,297	55,223	37,594	96,114	53,892
Other areas	9,737	4,891	26,879	19,699	36,616	24,589
Total	2,932,622	1,446,683	894,606	524,656	3,827,228	1,971,339

Marketing

Chesapeake s oil production is sold under market sensitive or spot price contracts. Our natural gas production is sold to purchasers under percentage-of-proceeds or percentage-of-index contracts and by direct marketing to end users or aggregators. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after gathering and processing our gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. The revenue we receive from the sale of natural gas liquids is included in natural gas sales. Under percentage-of-index contracts, the price per mmbtu we receive for our gas at the wellhead is tied to indexes published in *Inside FERC* or *Gas Daily*. During 2002, sales to Continental Natural Gas and Duke Energy Field Services of $90.2 million and $71.4 million, respectively, accounted for 22% of our total revenues. Management believes that the loss of one of these customers would not have a material adverse effect on our results of operations or our financial position. Other than the purchasers noted above, no other customer accounted for more than 10% of total revenues in 2002.

Chesapeake Energy Marketing, Inc., a wholly-owned subsidiary, provides marketing services, including commodity price structuring, contract administration and nomination services for Chesapeake and its partners. CEMI is a reportable segment under SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information.* See note 8 of notes to consolidated financial statements in Item 8.

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Hedging Activities

We utilize hedging strategies to hedge the price of a portion of our future oil and natural gas production and from time to time to manage interest rate exposure. See Item 7A Quantitative and Qualitative Disclosures About Market Risk.

Risk Factors

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock or other securities.

Oil and gas prices are volatile. A decline in prices could adversely affect our financial results, cash flows, access to capital and ability to grow.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and gas properties depend primarily upon the prices we receive for the oil and gas we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow from banks is subject to periodic redeterminations based on prices specified by our bank group at the time of redetermination. In addition, we may have ceiling test write-downs in the future if prices fall significantly.

Historically, the markets for oil and gas have been volatile and they are likely to continue to be volatile. Wide fluctuations in oil and gas prices may result from relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of oil and gas;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- risks associated with owning and operating drilling rigs;
- the availability of pipeline capacity;

- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions; and
- the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and gas price movements with any certainty. Declines in oil and gas prices would not only reduce revenue, but could reduce the amount of oil and gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and gas prices do not necessarily move in tandem. Because approximately 90% of our proved reserves are currently natural gas reserves, we are more affected by movements in natural gas prices.

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Our level of indebtedness and preferred stock may adversely affect operations and limit our growth, and we may have difficulty making debt service and preferred stock dividend payments on our indebtedness and preferred stock as such payments become due.

As of December 31, 2002, we had long-term indebtedness of $1.7 billion, none of which was bank indebtedness. As of February 21, 2003, we had long-term indebtedness of $1.76 billion, $104 million of which was bank indebtedness. As of March 31, 2003, we had $1.98 billion in long-term indebtedness, none of which was bank indebtedness, plus preferred stock outstanding having an aggregate liquidation preference of $349.9 million. Our long-term indebtedness represented 65% of our total book capitalization at December 31, 2002. We expect to be highly leveraged in the foreseeable future.

Our level of indebtedness and preferred stock affects our operations in several ways, including the following:

- a significant portion of our cash flows must be used to service our indebtedness; and our business may not generate sufficient cash flow from operations to enable us to continue to meet our obligations under our indebtedness and our stated dividends on our preferred stock;
- a high level of debt increases our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry; and the rights and preferences applicable to our preferred stock may limit our ability to pay dividends on our preferred stock and
- a high level of debt and preferred stock may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, or other general corporate purposes.

We may incur additional debt, including significant secured indebtedness, in order to make future acquisitions or to develop our properties. A higher level of indebtedness increases the risk that we may default on our existing debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

In addition, our bank borrowing base is subject to periodic redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Our industry is extremely competitive.

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial and other resources than we do.

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation, exploration and production. We face intense competition from both major and other independent oil and natural gas companies in each of the following areas:

- seeking to acquire desirable producing properties or new leases for future exploration; and

- seeking to acquire the equipment and expertise necessary to develop and operate our properties.

Many of our competitors have financial and other resources substantially greater than ours, and some of them are fully integrated oil companies. These companies may be able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

Our commodity price risk management activities may reduce the realized prices received for our oil and gas sales.

In order to manage our exposure to price volatility in marketing our oil and gas, we enter into oil and gas price risk management arrangements for a portion of our expected production. Commodity price risk management transactions may limit the prices we actually realize; and we may experience reductions in oil and gas revenues from our commodity price risk management activities in the future. The estimated fair value of our oil and gas derivative instruments outstanding as of February 20, 2003 is a liability of approximately $64 million. In addition, our commodity price risk management transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; or
- the counterparties to our contracts fail to perform under the contracts.

Some of our commodity price and interest rate risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations exceed certain levels. As of December 31, 2002, we were required to post a total of $24.5 million of collateral with two of our counterparties through letters of credit issued under our bank credit facility. As of February 21, 2003, we were required to post a total of $57.0 million of collateral. Future collateral requirements are uncertain and will depend on arrangements with our counterparties, highly volatile natural gas and oil prices and fluctuations in interest rates.

The actual quantities and present value of our proved reserves may prove to be lower than we have estimated.

This report contains estimates of our proved reserves and the estimated future net revenues from our proved reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

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

At December 31, 2002, approximately 26% of our estimated proved reserves by volume were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. These reserve estimates include the assumption that we will make significant capital expenditures to develop the reserves, including $248 million in 2003. You should be aware that the estimated costs may not be accurate, development may not occur as scheduled and results may not be as estimated.

You should not assume that the present values referred to in this document represent the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The December 31, 2002 present value is based on weighted average oil and gas prices of $30.18 per barrel of oil and $4.28 per mcf of natural gas. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

Any changes in consumption by oil and gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows.

The timing of both the production and the costs for the development and production of oil and gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

We may not have funds sufficient to make the significant capital expenditures required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our bank credit facility and debt and equity issuances. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and gas, and our success in developing and producing new reserves. If revenue were to decrease as a result of lower oil and gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flows from operations are not sufficient to fund our capital expenditure budget, we may not be able to access additional bank debt, debt or equity or other methods of financing to meet these requirements.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves will decline over time. In addition, approximately 26% of our total estimated proved reserves by volume at December 31, 2002 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We may not be able to successfully find and produce reserves economically in the future. In addition, we may not be able to acquire proved reserves at acceptable costs.

Acquisitions may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

Our recent growth is due in part to acquisitions of exploration and production companies and producing properties. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are uncertain and beyond our control. These factors include recoverable reserves, exploration potential, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties, which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties. In addition, competition for producing oil and gas properties is intense and many of our competitors have financial and other resources that are substantially greater than those available to us. Therefore, we may not be able to acquire oil and gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. For example, we might decide to pursue acquisitions or properties located in geographic regions other than the Mid-Continent region. To the extent that such acquired properties are substantially different from our existing properties, our ability to efficiently realize the economic benefits of such transactions may be limited.

Future price declines may result in a writedown of our asset carrying values.

We utilize the full cost method of accounting for costs related to our oil and gas properties. Under this method, all such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. However, these capitalized costs are subject to a ceiling test which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. The full cost ceiling is evaluated at the end of each quarter using the prices for oil and gas at that date. A significant decline in oil and gas prices from current levels, or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

Oil and gas drilling and producing operations are hazardous and expose us to environmental liabilities.

Oil and gas operations are subject to many risks, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, and other environmental

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hazards and risks. Our drilling operations involve risks from high pressures and from mechanical difficulties such as stuck pipes, collapsed casings and separated cables. If any of these risks occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and penalties; and
- suspension of operations.

Our liability for environmental hazards includes those created either by the previous owners of properties that we purchase or lease or by acquired companies prior to the date we acquire them. We maintain insurance against some, but not all, of the risks described above. Our insurance may not be adequate to cover casualty losses or liabilities. Also, in the future we may not be able to continue to obtain insurance at premium levels that justify its purchase.

Exploration and development drilling may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The new wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in wells we drill or participate in. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;

adverse weather conditions;

compliance with environmental and other governmental requirements; and

the high cost, or shortages or delays in the availability, of drilling rigs and equipment.

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

We depend, and will continue to depend in the foreseeable future, on the services of our officers and key employees with extensive experience and expertise in evaluating and analyzing producing oil and gas properties and drilling prospects, maximizing production from oil and gas properties, marketing oil and gas production, and developing and executing financing and hedging strategies. Our ability to retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business. We do not maintain key person life insurance on any of our personnel.

Lower oil and gas prices could negatively impact our ability to borrow.

Our current bank credit facility limits our borrowings to a borrowing base of $250 million as of December 31, 2002. The borrowing base is determined periodically at the discretion of a majority of the banks and is based in part on oil and gas prices. Additionally, some of our indentures contain covenants limiting our ability to incur indebtedness in addition to that incurred under our bank credit facility. These indentures limit our ability to incur additional indebtedness unless we meet one of two alternative tests. The first alternative is based on a percentage of our adjusted consolidated net tangible assets, which is determined using discounted future net revenues from proved oil and gas reserves as of the end of each year. As of December 31, 2002, we cannot incur additional indebtedness under this first alternative of the debt incurrence test. The second alternative is based on the ratio of our adjusted consolidated EBITDA to our adjusted consolidated interest expense over a trailing twelve-month period. As of December 31, 2002, we are permitted to incur significant additional indebtedness under this second alternative of the debt incurrence test. Lower oil and gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

Our oil and gas marketing activities may expose us to claims from royalty owners.

In addition to marketing our own oil and gas production, our marketing activities include marketing oil and gas production for working interest owners and royalty owners in the wells that we operate. These activities include the operation of gathering systems and the sale of oil and natural gas under various arrangements. Royalty owners have commenced litigation against a number of companies in the oil and gas production business claiming that amounts paid for production attributable to the royalty owners interest violated the terms of the applicable leases and state law, that deductions from the proceeds of oil and gas production were unauthorized under the applicable leases and that amounts received by upstream sellers should be used to compute the amounts paid to the royalty owners. Chesapeake presently is a defendant in four such cases commenced as class action suits. As new cases are decided and the law in this area continues to develop, our liability relating to the marketing of oil and gas may increase.

Regulation

General. The oil and gas industry is subject to regulation at the federal, state and local level, and some of the laws, rules and regulations that govern our operations carry substantial penalties for noncompliance. This regulatory burden increases our cost of doing business and, consequently, affects our profitability.

Exploration and Production. Our operations are subject to various types of regulation at the U.S. federal, state and local levels. Such regulation includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to regulation are:

- the location of wells,
- the method of drilling and completing wells,
- the surface use and restoration of properties upon which wells are drilled,
- the plugging and abandoning of wells,
- the disposal of fluids used or other wastes obtained in connection with operations,
- the marketing, transportation and reporting of production, and

the valuation and payment of royalties.

Our operations are also subject to various conservation regulations. These include the regulation of the size of drilling and spacing units (regarding the density of wells which may be drilled in a particular area) and the unitization or pooling of oil and gas properties. In this regard, some states, such as Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas, rely on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units and, therefore, more difficult to fully develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amount of oil and gas we can produce and to limit the number of wells or the locations at which we can drill.

We do not anticipate that compliance with existing laws and regulations governing exploration and production will have a significantly adverse effect upon our capital expenditures, earnings or competitive position.

Environmental Regulation. Various federal, state and local laws and regulations concerning the discharge of contaminants into the environment, the generation, storage, transportation and disposal of contaminants, and the protection of public health, natural resources, wildlife and the environment affect our exploration, development and production operations. We must take into account the cost of complying with environmental regulations in planning, designing, drilling, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production

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waste products, water and air pollution control procedures, and the remediation of petroleum-product contamination. In addition, our operations require us to obtain permits for, among other things,

- discharges into surface waters,
- discharges of storm water runoff,
- the construction of facilities in wetland areas, and
- the construction and operation of underground injection wells or surface pits to dispose of produced saltwater and other nonhazardous oilfield wastes.

Under state and federal laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by us or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations in contaminated areas, or to perform remedial plugging operations to prevent future contamination. The Environmental Protection Agency and various state agencies have limited the disposal options for hazardous and nonhazardous wastes. The owner and operator of a site, and persons that treated, disposed of or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of a hazardous substance into the environment. The Environmental Protection Agency, state environmental agencies and, in some cases, third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such action. Furthermore, certain wastes generated by our oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements.

Federal and state occupational safety and health laws require us to organize information about hazardous materials used, released or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards.

We have made and will continue to make expenditures to comply with environmental regulations and requirements. These are necessary business costs in the oil and gas industry. Although we are not fully insured against all environmental risks, we maintain insurance coverage which we believe is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental laws and regulations, as well as claims for damages to property or persons resulting from company operations, could result in substantial costs and liabilities, including civil and criminal penalties, to Chesapeake. We believe we are in substantial compliance with existing environmental regulations, and that, absent the occurrence of an extraordinary event the effect of which cannot be predicted, any noncompliance will not have a material adverse effect on our operations or earnings.

Income Taxes

At December 31, 2002, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $653 million. Additionally, we had approximately $300 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $8 million of percentage depletion carryforwards. The NOL carryforwards expire from 2010 through 2022. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs.

The ability of Chesapeake to utilize NOL carryforwards to reduce future federal taxable income and federal income tax is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of Chesapeake.

In the event of an ownership change (as defined for income tax purposes), Section 382 of the Code imposes an annual limitation on the amount of a corporation s taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Chesapeake had an ownership change in March 1998 which triggered a limitation. Certain NOLs acquired through various acquisitions are also subject to limitations. Of the

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$653 million NOLs and $300 million AMT NOLs, $346 million and $83 million, respectively, are limited under Section 382. Therefore, $307 million of the NOLs and $217 million of the AMT NOLs are not subject to the limitation. The utilization of $346 million of the NOLs and the utilization of $83 million of the AMT NOLs subject to the Section 382 limitation are limited to approximately $41 million and $15 million, respectively, each taxable year. Although no assurances can be made, we do not believe that an additional ownership change has occurred as of December 31, 2002. Equity transactions after the date hereof by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

In the event of another ownership change, the amount of Chesapeake s NOLs available for use each year will depend upon future events that cannot currently be predicted and upon interpretation of complex rules under Treasury regulations. If less than the full amount of the annual limitation is utilized in any given year, the unused portion may be carried forward and may be used in addition to successive years annual limitation.

We expect to utilize our NOL carryforwards and other tax deductions and credits to offset taxable income in the future. However, there is no assurance that the Internal Revenue Service will not challenge these carryforwards or their utilization.

In 2002, the Internal Revenue Service completed an audit of Chesapeake for the years ended December 31, 1999 and 2000. There were no significant adjustments resulting from this audit.

Title to Properties

Our title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the oil and gas industry, to liens for current taxes not yet due and to other encumbrances. As is customary in the industry in the case of undeveloped properties, only cursory investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and gas industry. Nevertheless, we are involved in title disputes from time to time which result in litigation. See Item 3 Legal Proceedings for a description of pending cases challenging certain of our oil and gas leasehold interests in the West Panhandle Field of Texas.

Operating Hazards and Insurance

The oil and gas business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. If any of these should occur, Chesapeake could suffer substantial losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. Our horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

Chesapeake maintains a $50 million oil and gas lease operator policy that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. There can be no assurance that this insurance will be adequate to cover any losses or exposure to liability. We also carry comprehensive general liability policies and a $75 million umbrella policy. We carry workers compensation insurance in all states in which we operate and a $1 million employment practice liability policy. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks.

Employees

Chesapeake had 866 employees as of December 31, 2002, which includes 123 employed by our drilling rig subsidiary, Nomac Drilling Corporation. No employees are represented by organized labor unions. We believe our employee relations are good.

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Glossary

The terms defined in this section are used throughout this Form 10-K.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of gas equivalent.

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

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

Commercial Well; Commercially Productive Well. An oil and gas well which produces oil and gas in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

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

Dry Hole; Dry Well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Exploratory Well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Full Cost Pool. The full cost pool consists of all costs associated with property acquisition, exploration, and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration and development activities are included. Any costs related to production, general corporate overhead or similar activities are not included.

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

Horizontal Wells. Wells which are drilled at angles greater than 70 degrees from vertical.

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

Mbtu. One thousand btus.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of gas equivalent.

Net Acres or Net Wells. The sum of the fractional working interest owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

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

Productive Well. A well that is producing oil or gas or that is capable of production.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production responses that increased recovery will be achieved.

Proved Reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved Undeveloped Location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved Undeveloped Reserves. 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. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves may not include estimates attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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

Standardized Measure of Discounted Future Net Cash Flows. The discounted future net cash flows relating to proved reserves based on year-end prices, costs and statutory tax rates (adjusted for permanent differences) and a 10-percent annual discount rate.

Tcf. One trillion cubic feet.

Tcfe. One trillion cubic feet of gas equivalent.

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

Working Interest. The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Written Put Option. An option, exercisable by the buyer, to require the seller (writer) to sell a specified amount of a commodity at an agreed upon price and time. The buyer pays the seller (writer) a premium for entering into the transaction.

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ITEM 2. ***Properties***

Chesapeake focuses its natural gas exploration, development and acquisition efforts in one primary operating area and in three secondary operating areas: (i) the Mid-Continent (consisting of Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle), representing 86% of our proved reserves, (ii) the Gulf Coast region consisting primarily of the Deep Giddings Field in Texas and the Austin Chalk and Tuscaloosa Trends in Louisiana, representing 6% of our proved reserves, (iii) the Permian Basin region of southeastern New Mexico, representing 5% of our proved reserves and (iv) the Williston Basin of eastern Montana and western North Dakota, representing 3% of our proved reserves. In October 2001, we sold our Canadian subsidiary which included all of our Canadian properties and leasehold.

During the year ended December 31, 2002, we participated in 708 gross (279.2 net) wells, 269 of which we operated. A summary of our development, exploration, acquisition and divestiture activities by operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Capital Expenditures Oil and Gas Properties					
			Drilling	Leasehold	Sub-Total	Acquisition	Sales of Properties	Total
					($ in thousands)			
Mid-Continent	673	263.1	$ 322,407	$ 37,421	$ 359,828	$ 391,705	$ (839)	$ 750,694
Gulf Coast	13	6.3	20,944	3,724	24,668	397		25,065
Permian Basin	19	8.8	10,318	3,589	13,907	2		13,909
Williston Basin and other	3	1.0	4,426		4,426	877		5,303
Total	708	279.2	$ 358,095	$ 44,734	$ 402,829	$ 392,981	$ (839)	$ 794,971

Chesapeake s proved reserves increased 24% during 2002 to an estimated 2,205 bcfe at December 31, 2002, compared to 1,780 bcfe of estimated proved reserves at December 31, 2001 (See note 11 of notes to consolidated financial statements in Item 8).

Chesapeake s strategy for 2003 is to continue developing our natural gas assets through exploratory and developmental drilling and by selectively acquiring strategic properties in the Mid-Continent area. We have budgeted approximately $475 to $525 million for drilling, acreage acquisition, seismic and related capitalized internal costs, all of which is expected to be funded out of operating cash flow based on our current assumptions. Our budget is frequently adjusted based on changes in oil and gas prices, drilling results, drilling costs and other factors.

Primary Operating Area

Mid-Continent. Chesapeake s Mid-Continent proved reserves of 1,903 bcfe represented 86% of our total proved reserves as of December 31, 2002, and this area produced 147.3 bcfe, or 81%, of our 2002 production. During 2002, we invested approximately $322.4 million to drill 673 (263.1 net) wells in the Mid-Continent. We anticipate spending approximately 90% to 95% of our total budget for exploration and development activities in the Mid-Continent region during 2003. We anticipate the Mid-Continent will contribute approximately 194 bcfe, or 84%, of expected total production during 2003. Substantially all of our budgeted production is expected to come from proved reserves estimated as of December 31, 2002.

Secondary Operating Areas

Gulf Coast. Chesapeake s Gulf Coast proved reserves (consisting primarily of the Deep Giddings Field in Texas and the Austin Chalk and Tuscaloosa Trends in Louisiana) represented 142 bcfe, or 6%, of our total proved reserves as of December 31, 2002. During 2002, the Gulf Coast assets produced 23.3 bcfe, or 13%, of our total production. During 2002, we invested approximately $20.9 million to drill 13 (6.3 net) wells in the Gulf Coast. We anticipate the Gulf Coast will contribute approximately 26 bcfe, or 11%, of expected total production during 2003. Substantially all of our budgeted production is expected to come from proved reserves estimated as of December 31, 2002. We anticipate spending approximately 5% of our total budget for exploration and development activities in the Gulf Coast region during 2003.

Permian Basin. Chesapeake s Permian Basin proved reserves (consisting primarily of the Lovington area in New Mexico) represented 113 bcfe, or 5%, of our total proved reserves as of December 31, 2002. During 2002, the Permian assets produced 7.6 bcfe, or 4%, of our total production. We anticipate the Permian Basin will contribute approximately 8 bcfe, or 3%, of expected total production during 2003. Substantially all of our budgeted production is expected to come from proved reserves estimated as of December 31, 2002. During 2002, we invested approximately $10.3 million to drill 19 (8.8 net) wells in the Permian Basin. For 2003, we anticipate spending approximately 2% of our total budget for exploration and development activities in the Permian Basin.

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In September 2002, we announced our intention to dispose of our assets in the Permian Basin, either by a cash sale or an exchange for Mid-Continent properties. We have decided not to divest the Permian Basin assets as a result of recent favorable drilling results and higher oil and gas prices.

Williston Basin. Chesapeake s Williston Basin proved reserves represented 38 bcfe, or 2%, of our total proved reserves as of December 31, 2002. During 2002, the Williston assets produced 3.2 bcfe, or 2%, of our total production. We anticipate the Williston Basin will contribute approximately 4 bcfe, or 2%, of expected total production during 2003. Substantially all of our budgeted production is expected to come from proved reserves estimated as of December 31, 2002. During 2002, we invested approximately $4.4 million to drill 3 (1.0 net) wells in the Williston Basin. For 2003, we have not budgeted any exploration and development activities in the Williston Basin.

Oil and Gas Reserves

The tables below set forth information as of December 31, 2002 with respect to our estimated proved reserves, the associated estimated future net revenue and the present value at such date. Ryder Scott Company L.P. evaluated 20%, Lee Keeling and Associates evaluated 23%, Netherland, Sewell & Associates, Inc. evaluated 20% and Williamson Petroleum Consultants, Inc. evaluated 10% of our combined discounted future net revenues from our estimated proved reserves at December 31, 2002. The remaining 27% was evaluated internally by our engineers. All estimates were prepared based upon a review of production histories and other geologic, economic, ownership and engineering data we developed. The present value of estimated future net revenue shown is not intended to represent the current market value of the estimated oil and gas reserves we own.

Estimated Proved Reserves as of December 31, 2002	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
Proved developed	28,111	1,458,284	1,626,952
Proved undeveloped	9,476	521,317	578,173
Total proved	37,587	1,979,601	2,205,125

Estimated Future Net Revenue as of December 31, 2002(a)	Proved Developed	Proved Undeveloped	Total Proved
		($ in thousands)	
Estimated future net revenue	$ 5,213,550	$ 1,545,319	$ 6,758,869
Present value of future net revenue	$ 2,849,681	$ 867,964	$ 3,717,645(b)

(a) Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at December 31, 2002. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization. The prices used in the external and internal reports yield weighted average wellhead prices of $30.18 per barrel of oil and $4.28 per mcf of gas. These prices should not be interpreted as a prediction of future prices.

(b) The standardized measure of discounted future net cash flows at December 31, 2002 was $2,833,918,000.

The future net revenue attributable to our estimated proved undeveloped reserves of $1.5 billion at December 31, 2002, and the $868 million present value thereof, have been calculated assuming that we will expend approximately $570 million to develop these reserves. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, product prices and the availability of capital.

No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the Securities and Exchange Commission.

Chesapeake s ownership interest used in calculating proved reserves and the associated estimated future net revenue were determined after giving effect to the assumed maximum participation by other parties to our farmout and participation agreements. The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for oil and gas production sold subsequent to December 31, 2002. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices.

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There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond Chesapeake s control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates, and such revisions may be material. Accordingly, reserve estimates are often different from the actual quantities of oil and gas that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and cost, that may not prove correct. The foregoing uncertainties are particularly true as to proved undeveloped reserves, which are inherently less certain than proved developed reserves and which comprise a significant portion of our proved reserves. In addition, the estimated future net revenue from proved reserves and the associated present value does not include any estimates of corporate overhead, debt service costs, future income tax expense, or depreciation, depletion and amortization expense.

See Item 1 Business and note 11 of notes to consolidated financial statements included in Item 8 for a description of drilling, production and other information regarding our oil and gas properties.

Facilities

Chesapeake owns an office building complex in Oklahoma City and field offices in Lindsay, Waynoka, and Weatherford, Oklahoma; Garden City, Kansas; Borger, Dumas and College Station, Texas; and Eunice and Hobbs, New Mexico. In addition, Chesapeake leases field office space in Forgan, Kingfisher, Sayre and Wilburton, Oklahoma; Navasota, Texas; and Dickinson, North Dakota. Chesapeake owns 40 different gas gathering and processing facilities located in Oklahoma, Kansas and Louisiana.

ITEM 3. ***Legal Proceedings***

We are currently involved in various routine disputes incidental to our business operations. We believe that the final resolution of such currently pending or threatened litigation is not likely to have a material adverse effect on our financial position or results of operations. In addition, the following matters are pending:

One of our subsidiaries has been a defendant in 16 lawsuits filed between June 1997 and December 2001 by royalty owners seeking the termination of certain of our gas leases located in the West Panhandle Field in Texas. Because of inconsistent jury verdicts in four of the cases tried to date and because the amount of damages sought is not specified in all of the pending cases, the outcome of any future trials and appeals could not be predicted. As a result, management determined that these cases should be reported as material pending legal proceedings, and we have done so beginning with our Form 10-Q for the quarter ended June 30, 1999. Management has reevaluated the risk of liability posed by these cases primarily as a result of a recent decision by the Texas Supreme Court interpreting a lease provision similar to the lease provision at issue in our litigation. In light of this decision, management has concluded that the damages, if any, that might be awarded to plaintiffs in the lease cessation cases pending against us would not have a material adverse effect on our financial position or results of operations. Because our assessment of the lease cessation cases has changed, we have reversed approximately $3 million of the reserve previously established in connection with these cases as a reduction to general and administrative expenses during 2002.

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

Not applicable.

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PART II

ITEM 5. ***Market for Registrant s Common Equity and Related Stockholder Matters***

Price Range of Common Stock

Our common stock trades on the New York Stock Exchange under the symbol CHK. The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock as reported by the New York Stock Exchange:

	Common Stock	
	High	**Low**
Year ended December 31, 2002:		
First Quarter	$ 7.78	$ 5.05
Second Quarter	8.55	6.81
Third Quarter	7.25	4.50
Fourth Quarter	8.06	5.89
Year ended December 31, 2001:		
First Quarter	$ 11.06	$ 7.65
Second Quarter	9.45	6.20
Third Quarter	6.96	4.50
Fourth Quarter	7.59	5.26

At February 24, 2003 there were 1,177 holders of record of our common stock and approximately 48,000 beneficial owners.

Dividends

On September 20, 2002, our board of directors declared a $0.03 per share dividend on our common stock which was paid in October 2002. On December 20, 2002, our board of directors declared a $0.03 per share dividend on our common stock which was paid on January 15, 2003. Prior to the October dividend, we had not paid a dividend on our common stock since 1998. While we expect to continue to pay dividends on our common stock, the payment of future cash dividends will depend upon, among other things, our financial condition, funds from operations, the level of our capital and development expenditures, our future business prospects, any contractual restrictions and any other factors considered relevant by the board of directors.

Our revolving credit agreement limits the amount of cash dividends we may pay to $25.0 million per year, excluding dividends on our 6.75% cumulative convertible preferred stock. Four of the indentures governing our outstanding senior notes contain restrictions on our ability to declare and pay cash dividends. Under these indentures, we may not pay any cash dividends on our common or preferred stock if an event of default has occurred, if we have not met one of the two debt incurrence tests described in the indentures, or if immediately after giving effect to the dividend payment, we have paid total dividends and made other restricted payments in excess of the permitted amounts. As of December 31, 2002, our coverage ratio for purposes of the debt incurrence test was 2.9 to 1, compared to 2.25 to 1 required in our indentures.

ITEM 6. ***Selected Financial Data***

The following table sets forth selected consolidated financial data of Chesapeake for the twelve months ended December 31, 2002, 2001, 2000, 1999 and 1998. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items, as more fully described in Note 16 of Notes to Consolidated Financial Statements. Our acquisition of Gothic Energy Corporation in the first quarter of 2001, and the divestiture of our Canadian assets in October 2001, materially affect the comparability of the selected financial data for 2001 and 2000. The Gothic acquisition was accounted for using the purchase method. The table should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements, including the notes, appearing in Items 7 and 8 of this report.

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	Years Ended December 31,				
	2002	2001	2000	1999	1998
	($ in thousands, except per share data)				
	(Revised)	(Revised)			
Statement of Operations Data:					
Revenues:					
Oil and gas sales	$ 568,187	$ 820,318	$ 470,170	$ 280,445	$ 256,887
Oil and gas marketing sales	170,315	148,733	157,782	74,501	121,059
Total revenues	738,502	969,051	627,952	354,946	377,946
Operating costs:					
Production expenses	98,191	75,374	50,085	46,298	51,202
Production taxes	30,101	33,010	24,840	13,264	8,295
General and administrative	17,618	14,449	13,177	13,477	19,918
Oil and gas marketing expenses	165,736	144,373	152,309	71,533	119,008
Oil and gas depreciation, depletion and amortization	221,189	172,902	101,291	95,044	146,644
Depreciation and amortization of other assets	14,009	8,663	7,481	7,810	8,076
Impairment of oil and gas properties					826,000
Impairment of other assets					55,000
Total operating costs	546,844	448,771	349,183	247,426	1,234,143
Income (loss) from operations	191,658	520,280	278,769	107,520	(856,197)
Other income (expense):					
Interest and other income	7,340	2,877	3,649	8,562	3,926
Interest expense	(112,031)	(98,321)	(86,256)	(81,052)	(68,249)
Loss on investment in Seven Seas	(17,201)				
Loss on repurchases of debt	(2,626)	(76,667)			(13,334)
Impairments of investments in securities		(10,079)			
Gain on sale of Canadian subsidiary		27,000			
Gothic standby credit facility costs		(3,392)			
Total other income (expense)	(124,518)	(158,582)	(82,607)	(72,490)	(77,657)
Income (loss) before income taxes	67,140	361,698	196,162	35,030	(933,854)
Provision (benefit) for income taxes	26,854	144,292	(259,408)	1,764	
Net income (loss)	40,286	217,406	455,570	33,266	(933,854)
Preferred stock dividends	(10,117)	(2,050)	(8,484)	(16,711)	(12,077)
Gain on redemption of preferred stock			6,574		
Net income (loss) available to common shareholders	$ 30,169	$ 215,356	$ 453,660	$ 16,555	$ (945,931)
Earnings (loss) per common share					
Basic	$ 0.18	$ 1.33	$ 3.52	$ 0.17	$ (9.97)
Assuming Dilution	$ 0.17	$ 1.25	$ 3.01	$ 0.16	$ (9.97)
Cash dividends declared per common share	$ 0.06	$	$	$	$ 0.04
Cash Flow Data:					
Cash provided by operating activities before changes in working capital	$ 412,517	$ 518,563	$ 305,804	$ 138,727	$ 117,500
Cash provided by operating activities	432,531	553,737	314,640	145,022	94,639
Cash used in investing activities	779,745	670,105	325,229	153,908	548,050
Cash provided by (used in) financing activities	477,257	234,507	(27,740)	13,102	363,797
Effect of exchange rate changes on cash		(545)	(329)	4,922	(4,726)
Balance Sheet Data (at end of period):					
Total assets	$ 2,875,608	$ 2,286,768	$ 1,440,426	$ 850,533	$ 812,615

Long-term debt, net of current maturities	1,651,198	1,329,453	944,845	964,097	919,076
Stockholders equity (deficit)	907,875	767,407	313,232	(217,544)	(248,568)

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

Overview

The following table sets forth certain information regarding the production volumes, oil and gas sales, average sales prices received and expenses for the periods indicated:

	Years Ended December 31,		
	2002	**2001**	**2000**
Net Production:			
Oil (mbbl)	3,466	2,880	3,068
Gas (mmcf)	160,682	144,171	115,771
Gas equivalent (mmcfe)	181,478	161,451	134,179
Oil and Gas Sales ($ in thousands):			
Oil sales	$ 88,495	$ 69,602	$ 89,209
Oil derivatives realized gains (losses)	(1,092)	7,920	(8,256)
Oil derivatives unrealized gains (losses)	(7,369)	5,116	
Total oil sales	80,034	82,638	80,953
Gas sales	470,913	560,536	411,521
Gas derivatives realized gains (losses)	97,138	97,471	(22,304)
Gas derivatives unrealized gains (losses)	(79,898)	79,673	
Total gas sales	488,153	737.680	389,217
Total oil and gas sales	$ 568,187	$ 820,318	$ 470,170
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 25.53	$ 24.17	$ 29.08
Gas ($ per mcf)	$ 2.93	$ 3.89	$ 3.55
Gas equivalent ($ per mcfe)	$ 3.08	$ 3.90	$ 3.73
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 25.22	$ 26.92	$ 26.39
Gas ($ per mcf)	$ 3.54	$ 4.56	$ 3.36
Gas equivalent ($ per mcfe)	$ 3.61	$ 4.56	$ 3.50
Expenses ($ per mcfe):			
Production expenses and taxes	$ 0.71	$ 0.67	$ 0.56
General and administrative	$ 0.10	$ 0.09	$ 0.10
Depreciation, depletion and amortization	$ 1.22	$ 1.07	$ 0.75
Net Wells Drilled	279	245	177
Net Wells at End of Period	4,237	3,572	2,697

Recent Developments

Our 2003 results of operations will be significantly impacted by acquisitions of oil and gas properties we have recently completed or announced and the related financings of the pending acquisitions.

On January 31, 2003, we completed the acquisition of Mid-Continent gas assets from a wholly-owned subsidiary of Tulsa-based ONEOK, Inc. for $300 million. Based on internal reservoir engineering estimates, we believe the acquisition adds approximately 200 bcfe of proved reserves. The acquisition was funded with proceeds generated from the company s December 2002 issuance of 23 million common shares at $7.50 per share and $150 million of 7.75% senior notes.

On February 24, 2003, we announced that we had entered into an agreement to acquire El Paso Corporation s Anadarko Basin assets in western Oklahoma and the Texas Panhandle for $500 million, which, by our internal estimates, will add approximately 328 bcfe to our estimated proved reserves and approximately 67 mmcfe to our daily production. We expect to close the El Paso acquisition in March 2003.

On February 24, 2003, we announced that we had entered into an agreement to acquire Vintage Petroleum, Inc. s assets in the Bray field in southern Oklahoma for $30 million, which, by our internal estimates, will add approximately 22 bcfe to our estimated proved reserves and approximately 3.5 mmcfe to our daily production. We expect to close the Vintage acquisition in March 2003.

On February 25, 2003, we announced a proposed private placement of $300 million in aggregate principal amount of senior notes, a proposed public offering of 20,000,000 shares of common stock pursuant to our existing shelf registration statement and a proposed private placement of $200 million of convertible preferred stock. There is no assurance these proposed offerings will be completed or, if they are completed, that they will be completed for the amount contemplated.

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Results of Operations

General. For the year ended December 31, 2002, Chesapeake had net income of $40.3 million, or $0.17 per diluted common share, on total revenues of $738.5 million. This compares to net income of $217.4 million, or $1.25 per diluted common share, on total revenues of $969.1 million during the year ended December 31, 2001, and net income of $455.6 million, or $3.01 per diluted common share, on total revenues of $628.0 million during the year ended December 31, 2000. The 2002 net income includes, on a pre-tax basis, $88.0 million in net unrealized losses on oil and gas and interest rate derivatives, a $17.2 million impairment of our investment in Seven Seas Petroleum, Inc. and a $2.6 million loss on repurchases of debt. The 2001 net income included, on a pre-tax basis, $84.8 million in net unrealized gains on oil and gas derivatives, a $10.1 million impairment of certain equity investments, a $27.0 million gain on the sale of our Canadian subsidiary, a $3.4 million cost for an unsecured standby credit facility associated with the acquisition of Gothic Energy Corporation and a $76.7 million loss on repurchases of debt. Net income in 2000 was significantly enhanced by the reversal of a deferred tax valuation allowance in the amount of $265.0 million. The reversal related to Chesapeake s expected ability to generate sufficient future taxable income to utilize net operating losses prior to their expiration.

Oil and Gas Sales. During 2002, oil and gas sales were $568.2 million versus $820.3 million in 2001 and $470.2 million in 2000. In 2002, Chesapeake produced 181.5 bcfe at a weighted average price of $3.61 per mcfe, compared to 161.5 bcfe produced in 2001 at a weighted average price of $4.56 per mcfe, and 134.2 bcfe produced in 2000 at a weighted average price of $3.50 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains (losses) on derivatives). The decline in prices in 2002 resulted in a decline in revenue of $172 million offset by $92 million due to increased production, for a net decrease in revenues of $80 million (excluding unrealized gains (losses) on oil and gas derivatives). The increase in 2001 revenues (excluding unrealized gains (losses) on oil and gas derivatives) over 2000 revenues of $265 million is due to increased prices ($171 million) and increased production ($94 million).

The change in oil and gas prices has a significant impact on our oil and gas revenues and cash flows. Assuming the 2002 production levels, a change of $0.10 per mcf would result in an increase/decrease in revenues and cash flow of approximately $16 million and $15 million, respectively, and a change of $1.00 per barrel would result in an increase/decrease in revenues and cash flows of approximately $3.5 million and $3.3 million, respectively, without considering the effect of derivative activities.

For 2002, we realized an average price per barrel of oil of $25.22, compared to $26.92 in 2001 and $26.39 in 2000 (weighted average prices for all years discussed exclude the effect of unrealized gains (losses) on derivatives). Natural gas prices realized per mcf (excluding unrealized gains (losses) on derivatives) were $3.54, $4.56 and $3.36 in 2002, 2001 and 2000, respectively. Realized gains (losses) from our oil and gas derivatives resulted in a net increase in oil and gas revenues of $96.0 million or $0.53 per mcfe in 2002, a net increase of $105.4 million or $0.65 per mcfe in 2001 and a net decrease of $30.6 million or $0.23 per mcfe in 2000.

Effective January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*. This statement establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in oil and gas sales. For derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. See Hedging Activities below and Item 7A Quantitative and Qualitative Disclosures about Market Risk for additional information regarding our hedging activities.

Pursuant to SFAS 133, our cap-swaps, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. Therefore, changes in fair value of these instruments that occur prior to their maturity, together with any change in fair value of cash flow hedges resulting from ineffectiveness, are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and gas sales. These unrealized gains (losses) do not represent cash gains or losses.

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Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive SFAS 133 cash flow hedge accounting treatment.

Chesapeake recorded $87.3 million of net unrealized losses in 2002 on certain of our oil and gas derivatives that have not been designated as cash flow hedges in accordance with SFAS 133 compared to $84.8 million of net unrealized gains in 2001, and no such income (loss) in 2000.

The following table shows our production by region for 2002, 2001 and 2000:

	Years Ended December 31,					
	2002		2001		2000	
	mmcfe	Percent	mmcfe	Percent	mmcfe	Percent
Mid-Continent	147,348	81%	116,133	72%	78,342	58%
Gulf Coast	23,264	13	27,531	17	35,154	26
Canada			9,075	6	12,076	9
Permian Basin	7,637	4	5,029	3	6,166	5
Williston Basin and Other	3,229	2	3,683	2	2,441	2
Total production	181,478	100%	161,451	100%	134,179	100%

Natural gas production represented approximately 89% of our total production volume on an equivalent basis in 2002, compared to 89% in 2001 and 86% in 2000. The increase in production from 2000 through 2002 is due to the combination of organic production growth during the period as well as acquisitions completed in 2001 and 2002.

Oil and Gas Marketing Sales. Chesapeake realized $170.3 million in oil and gas marketing sales for third parties in 2002, with corresponding oil and gas marketing expenses of $165.7 million, for a net margin of $4.6 million. This compares to sales of $148.7 million and $157.8 million, expenses of $144.4 million and $152.3 million, and margins of $4.3 million and $5.5 million in 2001 and 2000, respectively. In 2002 and 2001, Chesapeake realized an increase in volumes related to oil and gas marketing sales, which was partially offset by a decrease in oil and gas prices for both years.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $98.2 million in 2002, compared to $75.4 million and $50.1 million in 2001 and 2000, respectively. On a unit of production basis, production expenses were $0.54 per mcfe in 2002 compared to $0.47 and $0.37 per mcfe in 2001 and 2000, respectively. The increase in costs on a per unit basis in 2002 and 2001 is due primarily to increased field service costs and higher production costs associated with properties acquired during these years. We expect that production expenses per mcfe in 2003 will range from $0.51 to $0.55.

Production Taxes. Production taxes were $30.1 million in 2002 compared to $33.0 million in 2001 and $24.8 million in 2000. On a unit of production basis, production taxes were $0.17, $0.20 and $0.19 per mcfe in 2002, 2001 and 2000, respectively. The decrease in 2002 of $2.9

million was due to a decrease in the average wellhead prices received for natural gas. The increase in 2001 of $8.2 million was due to an increase in production volumes and, to a lesser extent, an increase in the average wellhead prices received for natural gas. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and gas prices are higher. We expect production taxes per mcfe to range from $0.25 to $0.28 in 2003 based on our assumption that oil and natural gas wellhead prices will range from $4.00 to $4.50 per mcfe.

General and Administrative Expense. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and gas properties (see note 11 of notes to consolidated financial statements), were $17.6 million in 2002, $14.4 million in 2001 and $13.2 million in 2000. The increase in 2002 and 2001 is the result of the company s growth related to the various acquisitions which occurred in 2002 and 2001. We anticipate that general and administrative expenses for 2003 will be between $0.08 and $0.10 per mcfe, which is approximately the same level as 2002.

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $17.0 million, $12.9 million and $10.2 million of internal costs in 2002, 2001 and 2000, respectively, directly related to our oil and gas exploration and development efforts.

During 2002, we reversed approximately $3 million of our accrued liability previously established in connection with the West Panhandle Field cessation cases as a reduction to general and administrative expenses.

In connection with a legal proceeding brought against us by certain royalty owners, we determined that a portion of the marketing fee we had charged the royalty owners should be refunded. In late 2002, we deposited with the court $3.3 million to be held in an interest-bearing account for distribution to affected royalty owners which resulted in a charge to general and

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administrative expenses. A description of pending royalty owner litigation is included below under Liquidity and Capital Resources Contingencies.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties was $221.2 million, $172.9 million and $101.3 million during 2002, 2001 and 2000, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $1.22 (all domestic), $1.07 ($1.08 in U.S. and $0.90 in Canada), and $0.75 ($0.76 in U.S. and $0.71 in Canada) in 2002, 2001 and 2000, respectively. We expect the 2003 DD&A rate to be between $1.30 and $1.35 per mcfe. The increase in the average rate from 2000 to 2002 is primarily the result of higher drilling costs and higher costs associated with acquisitions.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $14.0 million in 2002, compared to $8.7 million in 2001 and $7.5 million in 2000. The increases in 2002 and 2001 were primarily the result of higher depreciation costs on fixed assets related to capital expenditures made in both years. Other property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 31.5 years, drilling rigs are depreciated over 12 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from three to seven years. To the extent the drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and gas properties as exploration or development costs. We expect 2003 depreciation and amortization of other assets to be between $0.08 and $0.10 per mcfe.

Interest and Other Income. Interest and other income was $7.3 million, $2.9 million and $3.6 million in 2002, 2001 and 2000, respectively. The increase in 2002 was the result of income recognized on our investments in Seven Seas and RAM and interest earned on overnight investments. The decrease in 2001 was the result of a decrease in miscellaneous non-oil and gas income offset by an increase in interest income.

Interest Expense. Interest expense increased to $112.0 million in 2002, compared to $98.3 million in 2001 and $86.3 million in 2000. The increase in 2002 is due to a $264 million increase in average long-term borrowings in 2002 compared to 2001. The increase in 2001 is due to a $260 million increase in average long-term borrowings in 2001 compared to 2000, partially offset by a decrease in the overall average interest rate. In addition to the interest expense reported, we capitalized $5.0 million of interest during 2002, compared to $4.7 million capitalized in 2001, and $2.4 million capitalized in 2000 on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using the weighted average interest rate on our outstanding borrowings. We expect 2003 interest expense to be between $0.65 and $0.70 per mcfe.

From time to time, we enter into derivative instruments designed to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value of interest rate derivatives are recorded on the consolidated balance sheets as assets (liabilities) and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Included in interest expense in 2002 are a realized gain of $6.1 million related to interest rate derivatives and a loss on ineffectiveness of $3.5 million. There were no such gains or losses in 2001 or 2000.

Loss on Investments in Seven Seas. In July 2001, Chesapeake purchased $22.5 million principal amount of 12% senior secured notes due 2004 issued by Seven Seas Petroleum, Inc. and detachable seven-year warrants to purchase approximately 12.6 million shares of Seven Seas common stock at an exercise price of approximately $1.78 per share. The 12% senior secured notes held by us, and the $22.5 million of notes acquired by other parties, are secured by a pledge of substantially all of the assets owned by Seven Seas.

In December 2002, Seven Seas announced that it was in default under the senior secured notes. On December 13, 2002, we accelerated all amounts owing to us. On December 14, 2002, Seven Seas announced that it had entered into an agreement with an independent third party to sell its interests in the Guaduas oil field in Colombia for $20 million. Later in December 2002, holders of its senior unsecured notes filed an involuntary Chapter 7 petition in bankruptcy against Seven Seas. In January 2003, the case was converted to a Chapter 11 proceeding and a bankruptcy trustee was appointed. The asset sale closed on February 21, 2003. Seven Seas has reported that the only material assets remaining are its rights associated with the Deep Dindal association contract and certain Colombian tax assets. Seven Seas has also said it will not have sufficient cash to conduct additional operations.

In the third quarter of 2002, Chesapeake recorded an impairment of $4.8 million representing 100% of the cost allocated to our Seven Seas common stock warrants. During the fourth quarter of 2002, we recorded an additional impairment of $12.4

million to reduce our net investment in the senior secured notes, including accrued interest, to $7.5 million, representing Chesapeake s anticipated share of the net proceeds from the liquidation of Seven Seas assets.

Loss on Repurchases of Debt. During 2002, we purchased and subsequently retired $107.9 million of our 7.875% senior notes due 2004 for total consideration of $112.9 million, including accrued interest of $1.3 million and $3.7 million of redemption premium partially offset by a $1.7 million gain from interest rate hedging activities associated with the retired debt. During 2001, we purchased or redeemed $500.0 million principal amount of our 9.625% senior notes, $202.3 million principal amount of the 11.125% senior secured notes of Gothic Production Corporation, a Chesapeake subsidiary, and $120.0 million principal amount of our 9.125% senior notes. The purchase and redemption of these notes included payment of aggregate make-whole and redemption premiums of $75.6 million and the write-off of unamortized debt costs and debt issue premiums resulting in a pre-tax loss of $76.7 million.

Impairments of Investments in Securities. During 2001 we recorded impairments to two equity investments of $10.1 million. The majority of this impairment was related to our investment in RAM Energy, Inc. In March 2001, we issued 1.1 million shares of Chesapeake common stock in exchange for 49.5% of RAM s outstanding common stock. Our shares were valued at $8.854 each, or $9.9 million in total. During 2001, we recorded our equity in RAM s net losses, which had the effect of reducing our carrying value in these securities to $8.6 million. In December 2001, we sold the RAM shares for minimal consideration. In addition, we reduced the carrying value of our $2.0 million investment in an Internet-based oil and gas business by $1.5 million to $0.5 million.

Gain on Sale of Canadian Subsidiary. In October 2001, we sold our Canadian subsidiary, which had oil and gas operations primarily in northeast British Columbia, for approximately $143.0 million. Under full-cost accounting, our investment in these Canadian oil and gas properties was treated as a separate cost center for accounting purposes. As a result of the sale of this cost center, any gain or loss on the disposition was required to be recognized in current earnings. In the fourth quarter of 2001, we recorded a gain on sale of our Canadian subsidiary of $27.0 million.

Gothic Standby Credit Facility Costs. During 2000, we obtained a standby commitment for a $275 million credit facility, consisting of a $175 million term loan and a $100 million revolving credit facility which, if needed, would have replaced our then existing revolving credit facility. The term loan was available to provide funds to repurchase any of Gothic Production Corporation s 11.125% senior secured notes tendered following the closing of the Gothic acquisition in January 2001 pursuant to a change-of-control offer to purchase. In February 2001, we purchased $1.0 million of notes tendered for 101% of such amount. We did not use the standby credit facility and the commitment terminated on February 23, 2001. Chesapeake incurred $3.4 million of costs for the standby facility, which were recognized in the first quarter of 2001.

Provision (Benefit) for Income Taxes. Chesapeake recorded income tax expense of $26.9 million in 2002, compared to income tax expense of $144.3 million in 2001 and income tax benefit of $259.4 million in 2000. All income tax expense for 2002 is related to our domestic operations. Income tax expense for 2001 is comprised of $127.6 million related to our domestic operations, $7.1 million related to our Canadian operations and $9.6 million related to the sale of our Canadian subsidiary. The income tax benefit in 2000 was comprised of $5.6 million of income tax expense related to our Canadian operations and the reversal of a $265 million deferred tax valuation allowance which was established in prior years. The valuation allowance had been established due to uncertainty surrounding our ability to utilize extensive regular tax NOLs prior to their expiration. Based upon our results of operations as of December 31, 2000, the improved outlook for the natural gas industry and our projected results of future operations, we believed it was more likely than not that Chesapeake would be able to generate sufficient future taxable income to utilize our existing NOLs prior to their expiration. Consequently, we determined that a valuation allowance was no longer required at December 31, 2000. As of December 31, 2001, we determined that it was more likely than not that $2.4 million of the deferred tax assets related to Louisiana net operating losses will not be realized and we recorded a valuation allowance equal to such amounts. Our expectations remain unchanged as of December 31, 2002.

Cash Flows From Operating, Investing and Financing Activities

Cash Flows from Operating Activities. Cash provided by operating activities (exclusive of changes in working capital) was $412.5 million in 2002, compared to $518.6 million in 2001 and $305.8 million in 2000. The $106.1 million decrease from 2001 to 2002 was primarily due to decreased oil and gas revenues resulting from lower prices partially offset by higher volumes and the increase in 2001 over 2000 was due to significantly higher gas prices and higher volumes of both oil and gas.

Cash Flows from Investing Activities. Cash used in investing activities increased to $779.7 million in 2002, compared to $670.1 million in 2001 and $325.2 million in 2000.

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During 2002, Chesapeake invested cash of $400.2 million for exploration and development drilling and $331.7 million for the acquisition of oil and gas properties, and we received $0.8 million related to divestitures of oil and gas properties. In 2002, we invested $2.4 million in securities of other companies. We also invested $3.6 million in drilling rig equipment, $17.0 million in our Oklahoma City office complex and $16.6 million on upgrading various other properties and equipment.

During 2001, Chesapeake invested cash of $421.0 million for exploration and development drilling and $316.7 million for the acquisition of oil and gas properties, and we received $1.4 million related to divestitures of oil and gas properties and $142.9 million for the sale of our Canadian subsidiary. In 2001, we invested $40.2 million in securities of other companies, including $22.5 million in notes and warrants of Seven Seas Petroleum Inc., $14.6 million in notes of RAM Energy, Inc. and $3.1 million in other equity securities. We also invested $14.1 million in drilling rig equipment, $11.0 million in our Oklahoma City office complex and $10.6 million on upgrading various other properties and equipment.

During 2000, Chesapeake invested $188.8 million for exploration and development drilling, invested $78.9 million for the acquisition of oil and gas properties, and received $1.5 million related to divestitures of oil and gas properties. We invested $36.7 million in connection with our acquisition of Gothic Energy Corporation, including the purchase of Gothic notes and acquisition related costs. We also invested $7.9 million in Advanced Drilling Technologies, L.L.C. Additionally in 2000, we invested $4.0 million in our Oklahoma City office complex.

Cash Flows from Financing Activities. Cash provided by financing activities was $477.3 million in 2002, compared to $234.5 million in 2001 and $27.7 million used in 2000.

During 2002, we borrowed $252.5 million under our bank credit facility and made repayments under this facility of $252.5 million. We incurred $2.9 million of deferred charges related to the amendment of our bank credit facility. In 2002, we received $298.1 million from the issuance of our $300 million 9% senior notes in August and November and $148.5 million from the issuance of our $150 million 7.75% senior notes in December. We incurred $7.2 million of costs related to the issuance of these notes. In December 2002, we issued $172.5 million in common stock and received $164.1 million of net proceeds. We received $3.8 million from the exercise of employee and director stock options. During 2002, we purchased and subsequently retired $107.9 million of our 7.875% senior notes for $111.6 million including redemption premium of $3.7 million. Preferred stock dividends of $10.2 million and common stock dividends of $5.0 million were paid in 2002.

During 2001, we borrowed $433.5 million under our bank credit facility and made repayments under this facility of $458.5 million. We incurred $6.6 million of deferred charges related to our credit facility. In 2001, we received $786.7 million from the issuance of our $800.0 million 8.125% senior notes in April and $249.7 million from the issuance of our $250.0 million 8.375% senior notes in November. We used $906.0 million to purchase or redeem various Chesapeake and Gothic senior notes. We incurred $8.1 million of costs related to the issuance of these notes. In November 2001, we issued $150.0 million in preferred stock and received $145.1 million of net proceeds. We received $3.2 million from the exercise of employee and director stock options. We paid $3.3 million for make-whole provisions in the fourth quarter 2001 related to the exchange of our common stock for RAM Energy, Inc. common stock which occurred in March 2001. Preferred stock dividends of $1.1 million were paid in 2001.

During 2000, we borrowed $244.0 million under our bank credit facility and made repayments under this facility of $262.5 million. Also in 2000, we paid $8.3 million in connection with exchanges of our preferred stock for our common stock and paid cash dividends of $4.6 million on our preferred stock. In connection with our purchase of Gothic notes in 2000, we received $7.1 million cash from the sellers of Gothic notes pursuant to make-whole provisions included in the purchase agreements.

Liquidity and Capital Resources

Sources of Liquidity

Chesapeake had working capital of $169.8 million at December 31, 2002, of which $247.7 million was cash. Another source of liquidity is our $250 million revolving bank credit facility (with a committed borrowing base of $250 million) which matures in June 2005. At February 21, 2003 we had $104 million of indebtedness under the bank credit facility. We expect we will have no bank indebtedness at the conclusion of our proposed securities offerings, assuming they are all successfully closed. If the proposed offerings do not close as planned, however, we may need to use all or substantially all of our available bank borrowings to fund our pending acquisitions, which could substantially limit our liquidity.

We believe we will have adequate resources, including budgeted operating cash flows, working capital and proceeds from our revolving bank credit facility, to fund our capital expenditure budget for drilling, land and seismic activities during 2003,

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which is currently estimated to be between $475 and $525 million. However, higher drilling and field operating costs, unfavorable drilling results or other factors could cause us to reduce our drilling program, which is largely discretionary. Based on our current cash flow assumptions, we expect operating cash flow to be between $600 million and $650 million. Any operating cash flow not needed to fund our drilling program will be available for acquisitions, debt repayment or other general corporate purposes in 2003.

A significant portion of our liquidity at December 31, 2002 is concentrated in cash, cash equivalents and accounts receivable. Financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in debt instruments and accounts receivables. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. The industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. Cash and cash equivalents are deposited with major banks or institutions with high credit ratings.

Our liquidity is not dependent on the use of off-balance sheet financing arrangements, such as the securitization of receivables or obtaining access to assets through special purpose entities. We have not relied on off-balance sheet financing arrangements in the past and we do not intend to rely on such arrangements in the future as a source of liquidity. We are not a commercial paper issuer.

Contractual Obligations

We completed an acquisition of Mid-Continent gas assets from a wholly-owned subsidiary of Tulsa-based ONEOK, Inc. in January 2003. We paid $300 million in cash for these assets, $15 million of which was paid in 2002.

We have a $250 million revolving bank credit facility (with a committed borrowing base of $250 million) which matures in June 2005. As of December 31, 2002, we had no outstanding borrowings under this facility and utilized $25.4 million of the facility for various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either the reference rate of Union Bank of California, N.A., or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to total facility usage. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to an annual commitment fee of 0.50%. Interest is payable quarterly.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, sell properties, pay dividends, purchase or redeem our capital stock, make investments or loans or purchase certain of our senior notes, create liens, and make acquisitions. The credit facility agreement requires us to maintain a current ratio (as defined) of at least 1 to 1 and a fixed charge coverage ratio (as defined) of at least 2.5 to 1. At December 31, 2002, our current ratio was 2.5 to 1 and our fixed charge coverage ratio was 2.9 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $5.0 million.

As of December 31, 2002, senior notes represented approximately $1.7 billion of our long-term debt and consisted of the following ($ in thousands):

7.875% senior notes due 2004	$ 42,137
8.375% senior notes due 2008	250,000
8.125% senior notes due 2011	800,000
9.0% senior notes due 2012	300,000
8.5% senior notes due 2012	142,665
7.75% senior notes due 2015	150,000
	$ 1,684,802

There are no scheduled principal payments required on any of the senior notes until March 2004, when $42.1 million is due. Debt ratings for the senior notes are B1 by Moody s Investor Service, B+ by Standard & Poor s Ratings Services and BB- by Fitch Ratings as of December 31, 2002. Debt ratings for our secured bank credit facility are Ba3 by Moody s Investor Service, BB by Standard & Poor s Ratings Services and BB+ by Fitch Ratings.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. All of our wholly owned subsidiaries except Chesapeake Energy Marketing, Inc. guarantee the notes. The indentures permit us to redeem the senior notes at any time at specified make-whole or redemption prices. The indentures for the 8.125%, 8.375%, 9.0% and 7.75% senior notes contain covenants limiting our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; incur liens; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The debt incurrence covenants do not affect our ability to borrow under or expand our secured credit facility. As of December 31, 2002, we estimate that secured commercial bank indebtedness of approximately $716 million could have been incurred under the most restrictive indenture covenant. The indenture covenants do not apply to Chesapeake Energy Marketing, Inc., which is our only unrestricted subsidiary.

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The table below summarizes our contractual obligations as of December 31, 2002:

	Payments Due By Period ($ in thousands)				
Contractual Obligations	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$ 1,684,802	$	$ 42,137	$	$ 1,642,665
Capital lease obligations					
Operating lease obligations	2,804	824	1,138	325	517
Purchase obligations					
Standby letters of credit	26,165	26,165			
Other long-term obligations	2,879	846	2,033		
Total contractual obligations	$ 1,716,650	$ 27,835	$ 45,308	$ 325	$ 1,643,182

Some of our commodity price and financial risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations with respect to our commodity price and financial risk management transactions exceed certain levels. At December 31, 2002, we were required to post $24.5 million collateral. Future collateral requirements are uncertain and will depend on arrangements with our counterparties, highly volatile natural gas and oil prices, and fluctuations in interest rates.

Investing and Financing Transactions

On June 28, 2002, we acquired Canaan Energy Corporation in a cash merger through a Chesapeake subsidiary, adding approximately 100 bcfe to our proved reserves. Under the agreement, all outstanding common shares of Canaan, other than the Canaan shares already owned by Chesapeake, were purchased at $18.00 per share in cash, and the outstanding options to acquire Canaan common stock were converted into the right to receive, for each share of Canaan common stock to be received upon exercise, the merger consideration less the per share exercise price and withholding taxes. The aggregate net cash consideration for the merger was $127 million, including the retirement of Canaan s outstanding indebtedness of approximately $43 million.

During the third quarter of 2002, we completed four separate acquisitions of Mid-Continent oil and gas properties for an aggregate cash purchase price of $165 million. We estimate these acquisitions added approximately 124 bcfe of proved reserves. The acquisitions included privately-held Focus Energy, Inc. and its related partnerships, the Mid-Continent assets of publicly-traded EnCana Corporation, the Mid-Continent assets of OG&E Energy Corp. and the Anadarko Basin assets of The Williams Companies, Inc.

During 2002, we purchased and subsequently retired $107.9 million of our 7.875% senior notes due 2004 for total consideration of $112.9 million, including accrued interest of $1.3 million and $3.7 million of redemption premium partially offset by a $1.7 million gain from interest rate hedging activities associated with the retired debt.

In July 2002, we filed a shelf registration statement with the Securities and Exchange Commission that permits us, over time, to sell up to $500 million of debt securities or common stock, in any combination. Net proceeds, terms and pricing of the offerings of securities issued under the shelf registration statement will be determined at the time of the offerings. We offered and sold $172.5 million of common stock in December 2002, pursuant to a supplement to the registration statement.

In August 2002, we closed a private offering of $250 million principal amount of 9.0% senior notes due 2012, all of which were exchanged in October 2002 for substantially identical notes registered under the Securities Act of 1933. The net proceeds from this issuance of $242.8 million were used to fund the acquisitions we completed in July and August 2002, and to purchase outstanding senior notes. On November 6, 2002, Chesapeake closed a private offering of an additional $50 million principal amount of 9.0% senior notes due 2012. The net proceeds from the offering of $51.3 million were used to purchase outstanding 7.875% senior notes and to repay amounts outstanding under our revolving bank credit facility. The 9.0% senior notes are guaranteed by the same subsidiaries that guarantee our other outstanding senior notes and are subject to covenants substantially similar to those contained in the indenture for our 8.375% senior notes.

On September 20, 2002, our board of directors declared a $0.03 per share dividend on the company s common stock which was paid in October 2002. Chesapeake has not paid a dividend on its common stock since 1998. The annualized cost of the common stock dividend will be about $23 million.

In December 2002, we closed a private offering of $150 million principal amount of 7.75% senior notes due 2015. The net proceeds from this issuance of $145.3 million were used to fund a portion of the acquisition of oil and gas properties from ONEOK, Inc. in January 2003. The 7.75% senior notes are guaranteed by the same subsidiaries that guarantee our other outstanding senior notes and are subject to covenants substantially similar to those contained in the indentures for our 8.375% and 9.0% senior notes.

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In December 2002, we issued 23,000,000 shares of Chesapeake common stock at $7.50 per share. The net proceeds from the offering of $164.1 million were used to finance a portion of the acquisition of oil and gas properties from ONEOK, Inc. in January 2003. These shares were issued under the shelf registration statement filed in July 2002.

Contingencies

Recently, royalty owners have commenced litigation against a number of oil and gas producers claiming that amounts paid for production attributable to the royalty owners interest violated the terms of applicable leases and state law, that deductions from the proceeds of oil and gas production were unauthorized under the leases, and that amounts received by upstream sellers should be used to compute the amounts paid to the royalty owners. Typically this litigation has taken the form of class action suits. There are presently four such suits filed against Chesapeake, two in Texas and two in Oklahoma. No class has been certified in any of them. In one of the Oklahoma cases, we determined that a portion of the marketing fee we had charged royalty owners should be refunded. In late 2002, we deposited with the court the aggregate amount of the fees we estimated should be refunded, $3.3 million, in an interest-bearing account for distribution to affected royalty owners. This was charged to general and administrative expenses. We do not believe any other claims made by royalty owners in the cases pending against us are valid. Even if the claims were upheld, we believe any damages awarded would not be material. This is a developing area of the law, however, and as new cases are decided, our potential liability relating to the marketing of oil and gas may increase or decrease. We will continue to monitor court decisions to ensure that our operations and practices minimize any exposure and to recognize any charges that may be appropriate when we can reasonably estimate a liability.

Application of Critical Accounting Policies

Readers of this document and users of the information contained in it should be aware of how certain events may impact our financial results based on the accounting policies in place. The four policies we consider to be the most significant are discussed below. The company s management has discussed each critical accounting policy with the audit committee of the company s board of directors.

The selection and application of accounting policies is an important process that changes as our business changes and as accounting rules are developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment to the specific set of circumstances existing in our business.

Hedging. From time to time, Chesapeake uses commodity price and financial risk management instruments to mitigate our exposure to price fluctuations in oil and natural gas and interest rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of oil and gas derivative transactions are reflected in oil and gas sales, and results of interest rate hedging transactions are reflected in interest expense. The changes in the fair value of derivative instruments not qualifying for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within oil and gas sales or interest expense.

Effective January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*. This statement establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in oil and gas sales. For derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. See Hedging Activities below and Item 7A Quantitative and Qualitative Disclosures about Market Risk for additional information regarding our hedging activities.

One of the primary factors that can have an impact on our results of operations is the method used to value our derivatives. We have established the fair value of all derivative instruments using estimates determined by our counterparties and

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subsequently evaluated internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Another factor that can impact our results of operations each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at the inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Due to the volatility of oil and natural gas prices and, to a lesser extent, interest rates, the company s financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2002 and 2001, the net market value of our derivatives was a liability of $45 million and an asset of $157 million, respectively. With respect to our derivatives held as of December 31, 2002, an increase or decrease in natural gas prices of $0.25 per mmbtu would increase or decrease the estimated fair value of our derivatives by approximately $15.6 million. An increase or decrease in crude oil prices of $1.00 per barrel would increase or decrease the estimated fair value of our derivatives by approximately $3.5 million.

Oil and Gas Properties. Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and gas properties are generally calculated on a well by well or lease or field basis versus the aggregated full cost pool basis. Additionally, gain or loss is generally recognized on all sales of oil and gas properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher oil and gas depreciation, depletion and amortization rate.

Capitalized costs are amortized on a composite unit-of-production method based on proved oil and gas reserves. As of December 31, 2002, approximately 73% of our present value (discounted at 10%) of estimated future net revenues of proved reserves was evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers reevaluate our reserves on a quarterly basis. Depreciation, depletion and amortization expense is based on the amount of estimated reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense will be significantly different if our estimate of remaining reserves changes significantly.

Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized. No income is recognized in connection with contractual services provided by Chesapeake on properties in which we hold an economic interest.

The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred. Unevaluated properties are grouped by major producing area where individual property costs are not significant and are assessed individually when individual costs are significant.

We review the carrying value of our oil and gas properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. The two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or a decline in prices can have a material impact on the present value of estimated future net revenues. The process of estimating natural gas and oil reserves is very complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increases the likelihood of significant changes in these estimates. In addition, the prices of natural gas and oil are volatile and change from period to period. Price increases directly impact the estimated revenues from our properties and the associated present value of future net revenues. Such changes also impact the economic life of our properties and thereby affect the quantity of reserves that can be assigned to a property.

The volatility of oil and natural gas prices and the impact of revisions to reserve estimates can have a significant impact on the company s financial condition and results of operations. From January 1, 1997 to December 31, 1998, we recorded ceiling test impairments of approximately $1.2 billion to our oil and gas properties largely as a result of lower commodity prices. In addition, our oil and gas depreciation, depletion and amortization rates have fluctuated between $0.71 per mcfe in 1999 to $1.28 in 2002 reflecting the impact of prices during these periods. As of December 31, 2002, a decrease in natural gas prices of $0.10 per mcf and a decrease in oil prices of $1.00 per barrel would reduce the company s estimated proved reserves of 2,205 bcfe by 3.0 bcfe and 0.8 bcfe, respectively, and would also reduce the company s present value of estimated future net revenues by approximately $99 million and $19 million, respectively.

Statement of Financial Accounting Standards No. 141, *Business Combinations* and Statement of Financial Accounting Standards No. 142, *Goodwill and Intangible Assets* were issued by the Financial Accounting Standards Board in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment.

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 have to be classified separately from oil and gas properties as intangible assets on our consolidated balance sheets. In addition, the disclosures required by SFAS 141 and 142 relative to intangibles would be included in the notes to the consolidated financial statements. Historically, we, like many other oil and gas companies, have included these rights as part of oil and gas properties, even after SFAS 141 and 142 became effective.

As it applies to companies like us that have adopted full cost accounting for oil and gas activities, we understand that this interpretation of SFAS 141 and 142 would only affect our balance sheet classification of proved oil and gas leaseholds acquired after June 30, 2001 and all of our unproved oil and gas leaseholds. We would not be required to reclassify proved reserve leasehold acquisitions prior to June 30, 2001 because we did not separately value or account for these costs prior to the adoption date of SFAS 141. Our results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and gas reserves would continue to be amortized in accordance with full cost accounting rules.

As of December 31, 2002 and December 31, 2001, we had undeveloped leaseholds of approximately $72.5 million and $66.2 million, respectively, that would be classified on our consolidated balance sheet as intangible undeveloped leasehold and developed leaseholds of an estimated $581.9 million and $252.8 million, respectively, that would be classified as intangible developed leasehold if we applied the interpretation discussed above.

We will continue to classify our oil and 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.

Income Taxes. As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which Chesapeake operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as derivative instruments, depreciation, depletion and amortization, and certain accrued liabilities for tax and accounting purposes. These differences and the net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. To the extent Chesapeake establishes a valuation allowance or increases or decreases this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the consolidated statement of operations.

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Under SFAS 109, *Accounting for Income Taxes*, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (a) the more positive evidence is necessary and (b) the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion or all of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years,
- whether the carryforward period is so brief that it would limit realization of tax benefits,
- future sales and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures, and
- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

Beginning in 1997 and continuing throughout 1998, we recorded various asset write-downs related to the impairment of our oil and gas properties. The write-downs and significant tax net operating loss carryforwards (caused primarily by expensing intangible drilling costs for tax purposes) resulted in a net deferred tax asset. From June 1997 through September 2000, management believed that it was more likely than not that the company would continue generating future tax net operating losses for the foreseeable future and consequently recorded a valuation allowance against our deferred tax asset. In the fourth quarter of 2000, we eliminated our existing valuation allowance resulting in the recognition of a $265.0 million income tax benefit. Based upon results of operations for the year ended December 31, 2000 and anticipated improvement in Chesapeake s outlook for sustained profitability, we believed that it was more likely than not that we would generate sufficient future taxable income to realize the tax benefits associated with our NOL carryforwards prior to their expiration. Aside from a small valuation allowance related to net operating losses generated in Louisiana, we continue to believe that it is more likely than not that we will generate sufficient future taxable income to realize the tax benefits associated with our NOL carryforwards prior to their expiration.

If (a) natural gas and oil prices were to decrease significantly below present levels (and if such decreases were considered other than temporary), (b) exploration, drilling and operating costs were to increase significantly beyond current levels, or (c) we were confronted with any other significantly negative evidence pertaining to our ability to realize our NOL carryforwards prior to their expiration, we may be required to provide a valuation allowance against our deferred tax asset. As of December 31, 2002 we have a deferred tax asset of $278.5 million, of which only $2.4 million had an associated valuation allowance.

Accounting for Business Combinations. Beginning in 1998, we have completed several business combinations. In the future, we may continue to grow our business through similar transactions. Prior to the issuance of SFAS 141, *Accounting for Business Combinations*, in 2001, we applied the guidance provided by Accounting Principles Board Opinion (APB) No. 16, and its interpretations, as well as various other authoritative literature and interpretations that address issues encountered in accounting for business combinations. We have accounted for all of our business combinations using the purchase method, which is the only method permitted under SFAS 141. The accounting for business combinations is complicated and involves the use of significant judgment.

Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether in the form of cash, assets, stock or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net of the amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain of the acquired assets.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices, where available, appraisals, comparisons to transactions for similar assets and liabilities and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Each of the business combinations completed during the past five years were of small-to-medium sized exploration and production companies with oil and gas interests primarily in the Mid-Continent. We believe that the consideration we have paid to acquire these companies has represented the fair value of the assets and liabilities acquired at the time of acquisition. Consequently, we have not recognized any goodwill from any of our business combinations, nor do we expect to recognize any goodwill from similar business combinations that we may complete in the future.

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Hedging Activities

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2002, our oil and gas derivative instruments were comprised of swaps, cap-swaps and basis protection swaps. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty. Because this derivative includes a written put option (i.e., the cap), cap-swaps do not qualify for designation as cash flow hedges (in accordance with SFAS 133) since the combination of the hedged item and the written put option do not provide as much potential for favorable cash flows as exposure to unfavorable cash flows.

Basis protection swaps are arrangements that guarantee a price differential of oil or gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap or cap-swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. At the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and gas sales in the month of related production.

When Chesapeake enters into a counter-swap with the same counterparty, to the extent that a right of setoff exists in accordance with the FASB Interpretation No. 39, we net the value of the swap and the counter-swap.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap.

Chesapeake enters into oil and gas derivative transactions in order to mitigate a portion of its exposure to adverse market changes in oil and gas commodity prices. Accordingly, we believe that any associated gains or losses from the derivative transactions should be reflected as adjustments to oil and gas sales on the consolidated statement of operations. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and gas sales. Unrealized gains (losses) included in oil and gas sales in 2002 and 2001 were ($87.3) million and $84.8 million, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to hedged risk, are recorded in other comprehensive income. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales. We recorded a loss on ineffectiveness of $3.6 million in 2002 and a gain on ineffectiveness of $2.5 million in 2001.

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The estimated fair values of our oil and gas derivative instruments as of December 31, 2002 and 2001 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2002	December 31, 2001
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price gas swaps	$ (21,523)	$ 6,268
Fixed-price gas cap-swaps	(50,732)	77,208
Gas basis protection swaps	8,227	
Fixed-price gas counter-swaps	37,048	
Fixed-price gas locked swaps	16,498	50,549
Gas collars		15,360
Fixed-price crude oil swaps	(1,799)	
Fixed-price crude oil cap-swaps	(2,252)	5,078
Fixed-price crude oil locked swaps		2,846
Estimated fair value	$ (14,533)	$ 157,309

Based upon the market prices at December 31, 2002, we expect to transfer approximately $4.1 million of loss included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually occur. All transactions hedged as of December 31, 2002 are expected to mature by December 31, 2003, with the exception of the basis protection swaps which extend to 2009.

Additional information concerning the fair value of our oil and gas derivative instruments is as follows:

	December 31, 2002	December 31, 2001
	($ in thousands)	
Fair value of contracts outstanding, beginning of year	$ 157,309	$ (89,288)
Change in fair value of contracts during period	(52,419)	351,989
Contracts realized or otherwise settled during the period	(96,046)	(105,392)
Fair value of new contracts when entered into during the period	(45,603)	
Fair value of contracts when closed during the period	22,226	
Fair value of contracts outstanding, end of year	$ (14,533)	$ 157,309

Interest Rate Hedging

We also utilize hedging strategies to manage interest rate exposure. Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement.

In March 2002, we entered into an interest rate swap to convert a portion of our fixed rate debt to floating rate debt. The terms of this swap agreement are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
March 2002 March 2004	$200,000,000	7.875%	U.S. six-month LIBOR in arrears plus 298.25 basis points

At the inception of the interest rate swap agreement, a portion of the interest rate swap was to convert $129.0 million of our 7.875% senior notes from fixed rate debt to variable rate debt. Under SFAS 133, a hedge of interest rate risk in a recognized fixed rate liability can be designated as a fair value hedge. The mark-to-market value of the portion of the swap designated as a hedge is therefore recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease in the carrying value of the debt. The fair value of the remaining portion of the swap that is not designated as a hedge is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease to interest expense. During 2002, $107.9 million face value of the 7.875% senior notes was purchased and subsequently retired. In connection with the repurchase of the 7.875% senior notes, interest rate swap hedging gains of $1.8 million related to the debt repurchased were recognized and reduced the loss on repurchases of debt.

In July 2002, we closed the above interest rate swap for a cash settlement of $7.5 million. As of December 31, 2002, the remaining balance to be amortized as a reduction to interest expense was $0.7 million, which related to debt that remained outstanding. During 2002, $ 5.0 million was recorded as a reduction to interest expense.

In June 2002, we