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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2003

☐ 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
9.0% Senior Notes due 2012	New York Stock Exchange
7.5% Senior Notes due 2013	New York Stock Exchange
7.75% Senior Notes due 2015	New York Stock Exchange
6.75% Cumulative Convertible Preferred Stock	New York Stock Exchange
6.00% Cumulative Convertible Preferred Stock	New York Stock Exchange
5.00% 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 ☒ 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 ☒ NO ☐

The aggregate market value of our common stock held by non-affiliates on June 30, 2003 was $1,953,097,620. At March 10, 2004, there were ___________ shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

PART I

ITEM 1. *Business*

General

We are one of the six 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. Also available on our website and in print to any shareholder, who so requests are copies of our Corporate Governance Principles', our Code of Business Conduct and Ethics for our directors, officers and employees, and the Charters of our Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee of the Board of Directors. References to "us", "we" and "our" in this report refer to Chesapeake Energy Corporation together with its subsidiaries.

At the end of 2003, we owned interests in approximately 15,000 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. We are building secondary operating areas in the Permian Basin region of western Texas and eastern New Mexico and in the South Texas and Texas Gulf Coast regions. The following table highlights our growth since 1998:

	Years Ended December 31,					
	2003	2002	2001	2000	1999	1998
Production (mmcfe)	268,356	181,478	161,451	134,179	133,492	130,277
Proved reserves (mmcfe)	3,168,575	2,205,125	1,779,946	1,354,813	1,205,595	1,091,348
Net income (loss) ($ in 000's)	$ 312,981	$ 40,286	$ 217,406	$ 455,570	$ 33,266	$ (933,854)

Recent Developments

We completed an acquisition of Permian Basin and Mid-Continent oil and gas assets from Concho Resources Inc. in January 2004. We paid approximately $420 million in cash for these assets, $10 million of which was paid in 2003.

We also completed an acquisition of South Texas gas assets in January 2004. We paid $65 million for these assets, $3.3 million of which was paid in 2003.

On January 14, 2004, we issued 23,000,000 shares of common stock at a price to the public of $13.51 per share. We used the net proceeds of this offering of approximately $298.3 million to finance a portion of the acquisitions completed in January 2004.

On January 14, 2004, we completed a public exchange offer in which we retired $458.5 million of our 8.125% senior notes due 2011 and $10.8 million of accrued interest and issued $72.8 million of our 7.75% senior notes due 2015 and $2.8 million of accrued interest and $433.5 million of our 6.875% senior notes due 2016 and $4.1 million of accrued interest.

In January and February of 2004, we issued an additional $37.0 million of our 6.875% senior notes due 2016 and $0.5 million of accrued interest in exchange for $24.3 million of our 8.125% senior notes due 2011 and $0.7 million of accrued interest and $9.1 million of our 7.75% senior notes due 2015 and $0.1 million of accrued interest in four private exchange transactions.

Business Strategy

Since Chesapeake's inception in 1989, our goal has been to create value for our investors by building one of the largest onshore natural gas resource bases in the United States. For the past six years, our strategy to accomplish this goal has been to build the dominant operating position in the Mid-Continent region, the third largest gas supply region in the U.S. In building this industry-leading position in the Mid-Continent, we have integrated an aggressive and technologically advanced drilling program with an active property consolidation program focused on corporate and property acquisitions of up to $500 million.

We have now started to build secondary regions of importance in the Permian Basin and in the South Texas and Texas Gulf Coast regions, areas to which we believe significant elements of our successful Mid-Continent strategy can be transferred. Key elements of this business strategy are further explained below:

- *Consistently Making High-Quality Acquisitions.* Our acquisition program is focused on small-to medium-sized acquisitions of natural gas properties, primarily in the Mid-Continent, that provide high-quality, long-lived production and significant development and higher potential deeper drilling opportunities. Since January 1, 2000, we have acquired $2.8 billion of such properties (largely through 24 separate transactions of greater than $10 million each) at an estimated average cost of $1.31 per mcfe of proved reserves. The vast majority of these acquisitions either increased our ownership in existing wells or fields or added additional drilling locations in our primary Mid-Continent operating area, and more recently in our secondary operating areas. We believe our recently completed acquisitions are significant steps in building a meaningful presence in these secondary operating areas. Because our primary and secondary operating areas contain many small companies seeking liquidity opportunities and larger companies seeking to divest of 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 currently conducting one of the three most active drilling programs in the United States with a program focused on finding significant new gas reserves, primarily in the Mid-Continent. During 2004, we expect to use 40-45 drilling rigs to drill approximately 500 company-operated prospects and expect to participate with 40-50 additional rigs in the drilling of an additional 500 wells drilled on outside-operated prospects. In the Mid-Continent, our drilling program is the most active in the region and is supported by our ownership of the region's largest undeveloped leasehold and 3-D seismic inventories. In addition, we are continuing to increase our drilling activity in our secondary operating areas and we have recently increased our drilling, land and seismic budgets to accommodate even greater activity in these areas. Across our operating areas, we seek a balanced approach to drilling with approximately one-third of our expenditures focused on targets located at depths shallower than 10,000 feet, one-third on medium depth drilling between 10-15,000 feet and one-third targeting deeper objectives below 15,000 feet.

- *Consistently Focusing on Building Regional Scale.* We believe one of the keys to success in the natural gas exploration industry is focus: building significant operating scale in a limited number of core operating areas. Achieving such scale provides many benefits, the most important of which are higher per unit revenues, lower per unit operating costs, greater rates of drilling success, a lower likelihood of making unsuccessful acquisitions and higher returns on invested capital. The company first began pursuing this focused strategy in the Mid-Continent in 1997 and it now has become the largest natural gas producer, the most active driller and the most active acquirer of undeveloped leases and producing properties in the Mid-Continent. Chesapeake believes this region, which trails only the Gulf Coast and Rocky Mountain basins in current U.S. gas production, has many attractive characteristics. These characteristics include long-lived natural gas properties with predictable decline curves; multi-pay geological targets that decrease drilling risk and result in an impressive drilling success rate of 91% over the past eleven years; favorable basis differentials to benchmark commodity prices; generally lower service costs than in more competitive or more remote basins; and a favorable regulatory environment with virtually no federal land ownership. The company believes its secondary operating areas possess many of these same favorable characteristics.

- *Consistently Focusing on Low Costs.* By minimizing lease operating costs and general and administrative expenses through focused activities and increased scale, we have been able to deliver attractive financial returns through all phases of the commodity price cycle. We believe our low cost structure is the result of management's effective cost-control programs, a high-quality asset base and the extensive and competitive services, gas processing and transportation infrastructures that exist in our key operating areas.

- *Consistently Improving the Company's Balance Sheet.* We have made significant progress in improving our balance sheet since the beginning of 1999. After the completion of our recent (January 2004) common stock and debt exchange offerings, we will have increased our shareholders' equity by $2.3 billion through a combination of earnings and common and preferred equity issuances since the beginning of 1999. During the past five years, our debt to total capitalization ratio has declined from 137% to 53% (pro forma for January 2004 activity). We plan to continue making reduction of the debt to total capitalization ratio one of our primary goals.

Based on our view that natural gas has become the fuel of choice to meet the growing demand for a clean-burning, domestically-produced fuel, we believe our focused natural gas acquisition, exploitation and exploration strategy should provide substantial growth opportunities in the years ahead. Although U.S. gas production has been steadily declining during the past three years, we have increased our natural gas production in each of the 14 years since our company's inception in 1989. Our production goal is to increase our overall production by 15% to 20% per year, with an estimated one-third of this growth generated organically through the drillbit and the remainder through future acquisitions. We have reached or exceeded this overall production goal in 9 of our 11 years as a public company.

Company Strengths

We believe the following six characteristics highlight our most important company strengths, distinguish us from other independent natural gas producers and help explain our strong track record of delivering value to shareholders since our IPO in 1993:

- *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 proved reserve levels (pro forma for the Concho and South Texas acquisitions closed in January 2004), our proved reserves-to-production ratio, or reserve life, is approximately 10.6 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 asset base in each of our primary and secondary operating areas through a balanced approach of acquisitions, exploitation and exploration.

- *Low-Cost Producer.* Our high-quality asset base, our management style and our location in Oklahoma City have enabled us to achieve a low operating and administrative cost structure. During 2003, our operating costs per unit of production were $0.89 per mcfe, which consisted of general and administrative expenses of $0.09 per mcfe, production expenses of $0.51 per mcfe and production taxes of $0.29 per mcfe. We believe this is one of the lowest cost structures among publicly traded independent oil and natural gas producers. We seek to control operations of the properties in which we own an interest. Currently we operate approximately 79% of our proved reserves. This large percentage of operational control provides us with a high degree of operating flexibility and cost control.

- *Successful Acquisition Program.* Our experienced asset acquisition team focuses on enhancing and expanding our existing assets in all three of our operating areas. These areas are characterized by long-lived natural gas reserves, low lifting costs, multiple geological targets, favorable basis differentials to benchmark commodity prices, well-developed oil and gas transportation infrastructures and considerable potential for further consolidation of assets. Since 1998, and including the recent Concho and South Texas acquisitions closed in January 2004, we have completed $3.7 billion in acquisitions at an average cost of $1.24 per mcfe of proved reserves. We are well-positioned to continue making attractive small and medium-sized acquisitions as a result of our extensive track record of identifying, completing and integrating multiple successful acquisitions, our large operating scale and our knowledge and expertise in the regions in which we operate.

- *Large Inventory of Drilling Projects.* During the 14 years since our inception, Chesapeake has been one of the ten most active drillers of new wells in the United States and the most active driller in the Mid-Continent. In addition, we have developed an industry-leading expertise in drilling deep vertical and horizontal wells in search of large natural gas accumulations in challenging reservoir conditions. We pursue deep drilling targets because of our view that most undiscovered gas reserves in the U.S. will be found at depths below 15,000 feet. In addition, our large 3-D seismic inventory, much of which is proprietary to Chesapeake, provides the company with significant advantages over our competitors, which largely prefer to drill shallower development wells. As a result of our aggressive land and seismic acquisition strategies, we have been able to accumulate an onshore leasehold position of approximately three million net acres (pro forma for the Concho and South Texas acquisitions closed in January 2004). On this very large acreage position, our technical teams have identified over 2,500 exploratory and developmental drillsites, representing approximately five years of future drilling opportunities.

- *Hedging Program.* We have used and intend to continue using hedging programs to reduce the risks inherent in producing oil and natural gas, commodities that are frequently characterized by significant price volatility. We believe this price volatility is likely to continue and may even increase in the years ahead, but that a producer can use this volatility to its benefit by taking advantage of prices when they exceed historical norms. Over the past three years, we have increased our oil and gas revenues by over $184.0 million through our successful hedging programs. We currently have gas hedges in place covering 69%, 27%, 11% and 8% of our anticipated gas production for 2004, 2005, 2006 and 2007 at average NYMEX prices of $5.32, $5.04, $4.88 and $4.76 per mcf, respectively. In addition, we have 78% of our projected oil production hedged for 2004 at an average NYMEX price of $28.68 per barrel of oil.

- *Entreprenuerial Management.* Our management team formed the company in 1989 with an initial capitalization of $50,000. Through the following years, our current management team has guided the company through various operational and industry challenges and extremes of oil and gas prices to create one of the six largest independent producers of natural gas in the U.S. with an enterprise value of over $5.8 billion. Our co-founders, Aubrey K. McClendon and Tom L. Ward, have been partners in the oil and gas industry for 21 years and beneficially own, as of March 10, 2004, approximately 15.7 million and 17.2 million of the company's 240 million 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.

	2003				2002				2001			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
United States												
Development:												
Productive	958	96%	401.0	97%	617	95%	237.7	95%	423	92%	196.9	94%
Non-productive	37	4	11.2	3	34	5	11.5	5	36	8	12.2	6
Total	995	100%	412.2	100%	651	100%	249.2	100%	459	100%	209.1	100%
Exploratory:												
Productive	76	86%	35.9	83%	47	82%	24.6	82%	36	70%	18.4	67%
Non-productive	12	14	7.5	17	10	18	5.4	18	17	30	9.0	33
Total	88	100%	43.4	100%	57	100%	30.0	100%	53	100%	27.4	100%
Canada[(1)]												
Development:												
Productive	—	—%	—	—%	—	—%	—	—%	17	94%	7.6	95%
Non-productive	—	—	—	—	—	—	—	—	1	6	0.4	5
Total	—	—%	—	—%	—	—%	—	—%	18	100%	8.0	100%

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

At December 31, 2003, we had 76 (29 net) wells in process. We own six rigs which are dedicated to drilling wells operated by Chesapeake and three additional rigs are under construction. Our drilling business is conducted through our wholly owned subsidiary, Nomac Drilling Corporation.

Well Data

At December 31, 2003, we had interests in 14,950 (5,873 net) producing wells, including properties in which we held an overriding royalty interest, of which 2,665 (942 net) were classified as primarily oil producing wells and 12,285 (4,931 net) were classified as primarily gas producing wells. Chesapeake operates approximately 5,990 of its 14,950 producing wells. During 2003, we drilled 442 (352 net) wells and participated in another 641 (104 net) wells operated by other companies. We operate approximately 79% of our proved reserves by volume.

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:

	2003	2002	2001		
	U.S.	U.S.	U.S.	Canada	Combined
Net Production:					
Oil (mbbl)	4,665	3,466	2,880	—	2,880
Gas (mmcf)	240,366	160,682	135,096	9,075	144,171
Gas equivalent (mmcfe)	268,356	181,478	152,376	9,075	161,451
Oil and Gas Sales ($ in thousands):					
Oil sales	$ 132,630	$ 88,495	$ 69,602	$ —	$ 69,602
Oil derivatives – realized gains (losses)	(12,058)	(1,092)	7,920	—	7,920
Oil derivatives – unrealized gains (losses)	(9,440)	(7,369	5,116	—	5,116
Total oil sales	$ 111,132	$ 80,034	$ 82,638	$ —	$ 82,638
Gas sales	$1,171,050	$ 470,913	$ 528,608	$ 31,928	$ 560,536
Gas derivatives – realized gains (losses)	(5,331)	97,138)	97,471	—	97,471
Gas derivatives – unrealized gains (losses)	19,971	(79,898	79,673	—	79,673
Total gas sales	$1,185,690	$ 488,153	$ 705,752	$ 31,928	$ 737,680
Total oil and gas sales	$1,296,822	$ 568,187	$ 788,390	$ 31,928	$ 820,318

	2003	2002	2001		
	U.S.	U.S.	U.S.	Canada	Combined
Average Sales Price					
(excluding gains (losses) on derivatives):					
Oil ($ per bbl)	$ 28.43	$ 25.53	$ 24.17	$ —	$ 24.17
Gas ($ per mcf)	$ 4.87	$ 2.93	$ 3.91	$ 3.52	$ 3.89
Gas equivalent ($ per mcfe)	$ 4.86	$ 3.08	$ 3.93	$ 3.52	$ 3.90
Average Sales Price					
(excluding unrealized gains (losses) on derivatives):					
Oil ($ per bbl)	$ 25.85	$ 25.22	$ 26.92	$ —	$ $ 26.92
Gas ($ per mcf)	$ 4.85	$ 3.54	$ 4.63	$ 3.52	$ $ 4.56
Gas equivalent ($ per mcfe)	$ 4.79	$ 3.61	$ 4.62	$ 3.52	$ $ 4.56
Expenses ($ per mcfe):					
Production expenses	$ 0.51	$ 0.54	$ 0.48	$ 0.26	$ $ 0.47
Production taxes	$ 0.29	$ 0.17	$ 0.22	$ —	$ $ 0.20
General and administrative	$ 0.09	$ 0.10	$ 0.09	$ .11	$ $ 0.09
Depreciation, depletion and amortization	$ 1.38	$ 1.22	$ 1.08	$ 0.90	$ $ 1.07

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, 2003 of $30.22 per barrel of oil and $5.68 per mcf of gas). These prices were based on the cash spot prices for oil and natural gas at December 31, 2003.

	Oil (mbbl)	Gas (mmcf)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value ($ in thousands)
Mid-Continent	35,213	2,529,939	2,741,216	86.5%	$ 6,301,690
South Texas and Texas Gulf Coast	4,239	230,891	256,323	8.1	695,573
Permian Basin	7,247	83,274	126,756	4.0	260,369
Williston Basin	4,721	5,293	33,619	1.1	58,130
Other areas	2	10,643	10,661	0.3	17,380
Total	51,422	2,860,040	3,168,575	100.0%	$ 7,333,142[a]

(a) The standardized measure of discounted future net cash flows at December 31, 2003 was $5.2 billion.

As of December 31, 2003, the present value of our proved developed reserves as a percentage of total proved reserves was 75%, and the volume of our proved developed reserves as a percentage of total proved reserves was 74%. Natural gas reserves accounted for 90% of the volume of total proved reserves at December 31, 2003.

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, 2003 present value of proved reserves of approximately $145 million and $25 million, respectively.

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,		
	2003	2002	2001
	($ in thousands)		
Development and leasehold costs	$ 543,371	$ 266,291	$ 333,672
Exploration costs	103,424	89,422	47,945
Acquisition costs:			
Proved properties	1,110,077	316,583	669,201
Unproved properties	198,394	14,000	35,132
Deferred income taxes	(4,903)	62,398	36,309
Sales of oil and gas properties	(22,156)	(839)	(151,444)
Geological and geophysical costs	38,181	22,798	7,131
Asset retirement obligation(a)	39,686	—	—
Capitalized internal costs	35,494	24,318	18,225
Total	$2,041,568	$ 794,971	$ 996,171

(a) The 2003 amount includes $24.1 million of asset retirement costs recorded as a result of implementation of SFAS 143 effective January 1, 2003.

Our development and leasehold costs included $229 million, $120 million and $121 million of expenditures in 2003, 2002 and 2001, 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, 2003 are estimated future development costs of $823 million related to the development of proved undeveloped reserves ($351 million in 2004, $276 million in 2005, $157 million in 2006 and $39 million in 2007 and beyond). Chesapeake's development drilling schedules are subject to revision and reprioritization throughout the year, resulting from unknowable factors such as the relative success in an individual 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, 2003 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	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	3,835,215	1,610,680	801,377	417,336	4,636,592	2,028,016
South Texas and Texas Gulf Coast	274,375	164,690	188,270	134,264	462,645	298,954
Permian Basin	69,324	51,683	94,926	61,727	164,250	113,410
Williston Basin and Other	65,146	31,558	102,230	81,546	167,376	113,104
Total	4,244,060	1,858,611	1,186,803	694,873	5,430,863	2,553,484

Marketing

Chesapeake's oil production is generally sold under market sensitive or spot price contracts. Our natural gas production is generally sold to purchasers under percentage-of-proceeds or percentage-of-index contracts. 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 transportation 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 oil sales. Under percentage-of-index contracts, the price per mmbtu we receive for our gas is tied to indexes published in *Inside FERC* or *Gas Daily*. During 2003, sales to Reliant Energy Services and Duke Energy Field Services of $189.1 million and $163.3 million, respectively, accounted for 11% and 10%, respectively, 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 2003.

Chesapeake Energy Marketing, Inc., Mayfield Processing, L.L.C. and MidCon Compression, L.P., which are our marketing subsidiaries, provide marketing services, including commodity price structuring, contract administration and nomination services for Chesapeake and its partners. These subsidiaries are 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.

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;
- 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 at December 31, 2003 are natural gas reserves, we are more affected by movements in natural gas prices.

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.

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, 2003, 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 $351 million in 2004. 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, 2003 present value is based on weighted average oil and gas prices of $30.22 per barrel of oil and $5.68 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. Future interest rates and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

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, producing properties and undeveloped leasehold. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of 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. It is our current intention to continue focusing on acquiring properties with development and exploration potential located in the Mid-Continent, South Texas and Permian regions. To the extent that we acquire properties substantially different from the properties in our primary operating regions or acquired properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as efficiently as in our prior acquisitions.

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 unit-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, adjusted for the impact of derivatives accounted for as cash flow hedges. A significant decline in oil and gas prices from current levels, or other factors, without other mitigating circumstances, could cause a future writedown of capitalized costs and a non-cash charge against future earnings. Chesapeake's aggregate present value of future net revenues plus the value of the unproved properties would equal the value of the oil and gas properties at December 31, 2003 assuming an index price of approximately $3.25 per mcf for gas and $32.25 per barrel for oil. If index prices were to fall below these levels, Chesapeake could experience a writedown of its oil and gas assets.

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, 2003, we had long-term indebtedness of $2.1 billion, none of which was bank indebtedness. Pro forma for the debt exchanges which occurred in January and February 2004 and excluding the 7.875% senior notes which were paid in March 2004 and the 8.5% senior notes which were called for redemption in March 2004, we had long-term indebtedness of $2.2 billion, $150.0 million of which was bank indebtedness, plus preferred stock outstanding having an aggregate liquidation preference of $552.4 million. Our long-term indebtedness represented 54% of our total book capitalization at December 31, 2003. 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 and preferred stock increases our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness may 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 or issue additional series of preferred stock, in order to make future acquisitions or to develop our properties. A higher level of indebtedness and additional preferred stock 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 hedging activities may reduce the realized prices received for our oil and gas sales and require us to provide collateral for hedging liabilities.

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 hedging may limit the prices we actually realize and therefore reduce oil and gas revenues in the future. The estimated fair value of our oil and gas derivative instruments outstanding as of February 29, 2004 is a liability of approximately $__ 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, 2003, we were required to post a total of $33.5 million of collateral with two of our counterparties through letters of credit issued under our bank credit facility. As of March 10, 2004, we were required to post a total of $69 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.

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.

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

Our bank credit facility limits our borrowings to a borrowing base of $350 million as of March 10, 2004. 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 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. The second alternative is based on the ratio of our adjusted consolidated EBITDA (as defined in all of our indentures) to our adjusted consolidated interest expense over a trailing twelve-month period. As of December 31, 2003, we are permitted to incur significant additional indebtedness under both of these debt incurrence tests. 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.

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.

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 drilling costs. 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.

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, 2003 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.

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 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.

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

- discharges into surface waters, 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, 2003, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $403.8 million. We also had approximately $71.5 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $8.5 million of percentage depletion carryforwards. The NOL carryforwards expire from 2012 through 2022. During 2003, we estimate that we will be able to utilize approximately $253.3 million of NOLs to reduce our 2003 federal taxable income. 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. The following table summarizes our net operating losses as of December 31, 2003 and any related limitations:

	Net Operating Losses		
	Total	Limited	Annual Limitation
		($ in thousands)	
Net operating loss	$ 403,840	$ 312,140	$ 46,658
AMT net operating loss	$ 71,519	$ 71,519	$ 21,081

Although no assurances can be made, we do not believe that an additional ownership change has occurred as of December 31, 2003. 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.

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 a $100 million comprehensive general liability umbrella policy. We provide workers’ compensation insurance coverage to employees in all states in which we operate and we maintain 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 1,192 employees as of December 31, 2003, which includes 128 employed by our drilling subsidiary, Nomac Drilling Corporation. No employees are represented by organized labor unions. We believe our employee relations are good.

Glossary of Oil and Gas Terms

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.

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.

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 87% of our proved reserves, (ii) the South Texas and Texas Gulf Coast region, representing 8% of our proved reserves, (iii) the Permian Basin region of southeastern New Mexico and West Texas, representing 4% of our proved reserves, and (iv) the Williston Basin of eastern Montana and western North Dakota, representing 1% 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, 2003, we participated in 1,083 gross (456 net) wells, 442 (352 net) of which we operated. A summary of our development, exploration, acquisition and divestiture activities by operating area is as follows:

			Capital Expenditures — Oil and Gas Properties					
	Gross Wells Drilled	Net Wells Drilled	Exploration and Drilling	Leasehold	Sub-Total	Acquisition	Sales of Properties	Total
				($ in thousands)				
Mid-Continent	984	403.0	$ 579,853	$ 80,261	$ 660,114	$ 1,061,289	$ (22,156)	$ 1,699,247
South Texas and Texas Gulf Coast	55	24.7	61,590	17,609	79,199	195,065	—	274,264
Permian Basin	44	27.9	33,446	10,563	44,009	23,452	—	67,461
Williston Basin and other	—	—	283	145	428	168	—	596
Total	1,083	455.6	$ 675,172	$ 108,578	$ 783,750	$ 1,279,974	$ (22,156)	$ 2,041,568

Chesapeake's proved reserves increased 44% during 2003 to an estimated 3,169 bcfe at December 31, 2003, compared to 2,205 bcfe of estimated proved reserves at December 31, 2002. See note 11 of notes to our consolidated financial statements in Item 8 of this report.

Chesapeake's strategy for 2004 is to continue developing our natural gas assets through exploratory and developmental drilling and by selectively acquiring strategic properties in the Mid-Continent and in our secondary areas. We have budgeted approximately $750 million to $800 million for drilling, acreage acquisition, seismic and related capitalized internal costs, all of which is expected to be funded with 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. We expect to fund future acquisitions through a combination of operating cash flow, our secured credit facility and new debt and equity issuances.

Primary Operating Area

Mid-Continent. Chesapeake's Mid-Continent proved reserves of 2,741 bcfe represented 87% of our total proved reserves as of December 31, 2003, and this area produced 233.6 bcfe, or 87%, of our 2003 production. During 2003, we invested approximately $579.9 million to drill 984 (403.0 net) wells in the Mid-Continent. We anticipate spending approximately 80% to 85% of our total budget for exploration and development activities in the Mid-Continent region during 2004. We anticipate the Mid-Continent will contribute approximately 256 bcfe, or 78%, of expected total production during 2004. Substantially all of our budgeted production is expected to come from proved reserves owned as of December 31, 2003.

Secondary Operating Areas

South Texas and Texas Gulf Coast. Chesapeake's South Texas and Texas Gulf Coast proved reserves represented 256 bcfe, or 8%, of our total proved reserves as of December 31, 2003. During 2003, the South Texas and Texas Gulf Coast assets produced 23.3 bcfe, or 9%, of our total production. During 2003, we invested approximately $61.6 million to drill 55 (24.7 net) wells in the South Texas and Texas Gulf Coast region. We anticipate this area will contribute approximately 38 bcfe, or 12%, of expected total production during 2004. Substantially all of our budgeted production is expected to come from proved reserves estimated as of December 31, 2003 and acquired in January 2004. We anticipate spending approximately 10% of our total budget for exploration and development activities in the South Texas and Texas Gulf Coast region during 2004.

Permian Basin. Chesapeake's Permian Basin proved reserves represented 127 bcfe, or 4%, of our total proved reserves as of December 31, 2003. During 2003, the Permian assets produced 8.5 bcfe, or 3%, of our total production. We anticipate the Permian Basin will contribute approximately 29 bcfe, or 9%, of expected total production during 2004. Substantially all of our budgeted production is expected to come from proved reserves estimated as of December 31, 2003 and acquired in January 2004. During 2003, we invested approximately $33.4 million to drill 44 (27.9 net) wells in the Permian Basin. For 2004, we anticipate spending approximately 5% of our total budget for exploration and development activities in the Permian Basin.

Williston Basin. Chesapeake's Williston Basin proved reserves represented 34 bcfe, or 1%, of our total proved reserves as of December 31, 2003. During 2003, the Williston assets produced 3 bcfe, or 1%, of our total production. We anticipate the Williston Basin will contribute approximately 2.6 bcfe, or 1%, of expected total production during 2004. Substantially all of our budgeted production is expected to come from proved reserves estimated as of December 31, 2003. During 2003, we did not drill any wells and we have not budgeted any 2004 exploration and development activities in the Williston Basin.

Oil and Gas Reserves

The tables below set forth information as of December 31, 2003 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 31%, Netherland, Sewell & Associates, Inc. evaluated 26%, and Lee Keeling and Associates evaluated 17% of our combined discounted future net revenues from our estimated proved reserves at December 31, 2003. The remaining 26% 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, 2003	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
Proved developed	38,442	2,121,734	2,352,389
Proved undeveloped	12,980	738,306	816,186
Total proved	51,422	2,860,040	3,168,575

Estimated Future Net Revenue as of December 31, 2003(a)	Proved Developed	Proved Undeveloped	Total Proved
		($ in thousands)	
Estimated future net revenue	$ 9,921,483	$ 3,152,535	$ 13,074,018
Present value of future net revenue	$ 5,508,497	$ 1,824,645	$ 7,333,142(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, 2003. 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 $30.22 per barrel of oil and $5.68 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, 2003 was $5.2 billion.

The future net revenue attributable to our estimated proved undeveloped reserves of $3.2 billion at December 31, 2003, and the $1.8 billion present value thereof, have been calculated assuming that we will expend approximately $823 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, 2003. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices.

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 of this report 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; Van Buren, Arkansas; Cheneyville, Louisiana; and Eunice and Hobbs, New Mexico. In addition, Chesapeake leases office space in Oklahoma City and Tulsa, Oklahoma and Midland, Texas and field office space in Forgan, Kingfisher, Sayre and Wilburton, Oklahoma; Zapata, Texas; and Dickinson, North Dakota. Chesapeake owns approximately 50 different gas gathering and processing facilities located in Oklahoma, Kansas, Texas and Louisiana.

ITEM 3. *Legal Proceedings*

We are currently involved in various 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.

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

Not applicable.

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, 2003:		
First Quarter	$ 8.64	$ 7.27
Second Quarter	11.45	7.45
Third Quarter	10.97	9.17
Fourth Quarter	14.00	10.66
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

At March 10, 2004 there were _____ holders of record of our common stock and approximately ______ beneficial owners.

Dividends

The following table sets forth the amount of dividends per share declared on Chesapeake common stock during the two years ended December 31, 2003:

	2003	2002
First Quarter	$ 0.030	$ —
Second Quarter	0.035	—
Third Quarter	0.035	0.030
Fourth Quarter	0.035	0.030

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 $50 million per year, excluding dividends on our 6.75%, 6.00% and 5.00% cumulative convertible preferred stock. Six 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, 2003, our coverage ratio for purposes of the debt incurrence test was 5.1 to 1, compared to 2.25 to 1 required in our indentures. Our adjusted consolidated net tangible assets exceeded 200% of our total indebtedness, as required in our indentures, by more than $1.3 billion.

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

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2003, 2002, 2001, 2000 and 1999. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. In addition to changes in the annual average prices for oil and gas and increased production from drilling activity, significant acquisitions in recent years also impacted comparability between years. See note 13 to notes to financial statements. 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.

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	($ in thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Oil and gas sales	$ 1,296,822	$ 568,187	$ 820,318	$ 470,170	$ 280,445
Oil and gas marketing sales	420,610	170,315	148,733	157,782	74,501
Total revenues	1,717,432	738,502	969,051	627,952	354,946
Operating costs:					
Production expenses	137,583	98,191	75,374	50,085	46,298
Production taxes	77,893	30,101	33,010	24,840	13,264
General and administrative	23,753	17,618	14,449	13,177	13,477
Oil and gas marketing expenses	410,288	165,736	144,373	152,309	71,533
Oil and gas depreciation, depletion and amortization	369,465	221,189	172,902	101,291	95,044
Depreciation and amortization of other assets	16,793	14,009	8,663	7,481	7,810
Provision for legal settlements	6,402	—	—	—	—
Total operating costs	1,042,177	546,844	448,771	349,183	247,426
Income (loss) from operations	675,255	191,658	520,280	278,769	107,520
Other income (expense):					
Interest and other income	2,827	7,340	2,877	3,649	8,562
Interest expense	(154,356)	(112,031)	(98,321)	(86,256)	(81,052)
Loss on investment in Seven Seas	(2,015)	(17,201)	—	—	—
Loss on repurchases of debt	(20,759)	(2,626)	(76,667)	—	—
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)	(174,303)	(124,518)	(158,582)	(82,607)	(72,490)
Income before income taxes and cumulative effect of accounting change	500,952	67,140	361,698	196,162	35,030
Income tax expense (benefit):					
Current	5,000	(1,822)	3,565	—	—
Deferred	185,360	28,676	140,727	(259,408)	1,764
Total income tax expense (benefit)	190,360	26,854	144,292	(259,408)	1,764
Net income before cumulative effect of accounting change, net of tax	310,592	40,286	217,406	455,570	33,266
Cumulative effect of accounting change, net of income taxes of $1,464,000	2,389	—	—	—	—
Net Income	312,981	40,286	217,406	455,570	33,266
Preferred stock dividends	(22,469)	(10,117)	(2,050)	(8,484)	(16,711)
Gain on redemption of preferred stock	—	—	—	6,574	—
Net income available to common shareholders	$ 290,512	$ 30,169	$ 215,356	$ 453,660	$ 16,555
Earnings per common share— basic:					
Income before cumulative effect of accounting change	$ 1.36	$ 0.18	$ 1.33	$ 3.52	$ 0.17
Cumulative effect of accounting change	0.02	—	—	—	—
	$ 1.38	$ 0.18	$ 1.33	$ 3.52	$ 0.17
Earnings per common share— assuming dilution:					
Income before cumulative effect of accounting change	$ 1.20	$ 0.17	$ 1.25	$ 3.01	$ 0.16
Cumulative effect of accounting change	0.01	—	—	—	—
	$ 1.21	$ 0.17	$ 1.25	$ 3.01	$ 0.16
Cash dividends declared per common share	$0.14	$ 0.06	$ —	$ —	$ —
Cash Flow Data:					
Cash provided by operating activities before changes in working capital	$ 903,929	$ 412,517	$ 518,563	$ 305,804	$ 138,727
Cash provided by operating activities	945,602	432,531	553,737	314,640	145,022
Cash used in investing activities	2,077,217	779,745	670,105	325,229	153,908
Cash provided by (used in) financing activities	924,559	477,257	234,507	(27,740)	13,102
Effect of exchange rate changes on cash	—	—	(545)	(329)	4,922
Balance Sheet Data (at end of period):					
Total assets	$4,572,291	$2,875,608	$2,286,768	$1,440,426	$ 850,533
Long-term debt, net of current maturities	2,057,713	1,651,198	1,329,453	944,845	964,097
Stockholders' equity (deficit)	1,732,810	907,875	767,407	313,232	(217,544)

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

Financial Data

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,		
	2003	2002	2001
Net Production:			
Oil (mbbl)	4,665	3,466	2,880
Gas (mmcf)	240,366	160,682	144,171
Gas equivalent (mmcfe)	268,356	181,478	161,451
Oil and Gas Sales ($ in thousands):			
Oil sales	$ 132,630	$ 88,495	$ 69,602
Oil derivatives – realized gains (losses)	(12,058)	(1,092)	7,920
Oil derivatives – unrealized gains (losses)	(9,440)	(7,369)	5,116
Total oil sales	111,132	80,034	82,638
Gas sales	1,171,050	470,913	560,536
Gas derivatives – realized gains (losses)	(5,331)	97,138	97,471
Gas derivatives – unrealized gains (losses)	19,971	(79,898)	79,673
Total gas sales	1,185,690	488,153	737,680
Total oil and gas sales	$ 1,296,822	$ 568,187	$ 820,318
Interest Expense ($ in thousands):			
Interest expense	$ 151,676	$ 114,695	$ 98,321
Interest derivatives – realized (gains) losses	(3,859)	(3,415)	—
Interest derivatives – unrealized (gains) losses	6,539	751	—
Total interest expense	$ 154,356	$ 112,031	$ 98,321
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 28.43	$ 25.53	$ 24.17
Gas ($ per mcf)	$ 4.87	$ 2.93	$ 3.89
Gas equivalent ($ per mcfe)	$ 4.86	$ 3.08	$ 3.90
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 25.85	$ 25.22	$ 26.92
Gas ($ per mcf)	$ 4.85	$ 3.54	$ 4.56
Gas equivalent ($ per mcfe)	$ 4.79	$ 3.61	$ 4.56
Expenses ($ per mcfe):			
Production expenses	$ 0.51	$ 0.54	$ 0.47
Production taxes	$ 0.29	$ 0.17	$ 0.20
General and administrative	$ 0.09	$ 0.10	$ 0.09
Depreciation, depletion and amortization	$ 1.38	$ 1.22	$ 1.07
Interest expense (a)	$ 0.55	$ 0.61	$ 0.61
Net Wells Drilled	456	279	245
Net Wells at End of Period	5,873	4,237	3,572

(a) includes the effects of realized gains or (losses) from hedging, but does not include the effects of unrealized gains or (losses) from hedging

Executive Summary

Chesapeake is the largest producer of natural gas in the Mid-Continent and is among the six largest independent producers of natural gas in the U.S. At the end of 2003, we owned interests in approximately 15,000 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. We are building secondary operating areas in the Permian Basin of western Texas and eastern New Mexico and in the South Texas and Texas Gulf Coast regions. The Company has achieved its current position as a result of a series of key management decisions made during the past six years. These decisions included favoring gas over oil, establishing regional dominance in our operating areas, delivering value-added growth through a balance of drilling and acquisitions and managing risk through opportunistic oil and natural gas hedging.

Oil and natural gas production for 2003 was 268 bcfe, an increase of 87 bcfe, or 48%, over the 181 bcfe produced in 2002. Of this 87 bcfe in year-over-year production growth, an estimated 36 bcfe was a result of organic drillbit growth while 51 bcfe was generated from acquisitions. We estimate our organic growth rate during 2003 was 20%, well above the company's forecasted organic growth rate of 5%.

We have increased our production annually for 14 consecutive years, which we believe is one of the best track records in the industry. In addition, the 2003 fourth quarter was Chesapeake's tenth consecutive quarter of sequential production growth. During the past ten quarters, Chesapeake's production has increased 87%, for an average sequential quarterly growth rate of 6.5% and an annualized growth rate of 28.1%

Chesapeake began 2003 with estimated proved reserves of 2,205 bcfe and ended the year with 3,169 bcfe, an increase of 964 bcfe, or 44%. Taking into account production of 268 bcfe, reserve replacement during the year was 1,232 bcfe, or 459%, at a finding and acquisition cost of $1.36 per mcfe. Our year-end 2003 proved reserves were 74% proved developed. Independent third-party reservoir engineers evaluated 74% of our estimated proved reserves at year-end 2003.

Of the 1,232 bcfe of proved reserve additions, acquisitions added 805 bcfe at a cost of $1.38 per mcfe and drilling, including positive revisions to previous estimates, added 438 bcfe for a reserve replacement rate from drilling of 163% at a cost of $1.32 per mcfe. Additionally, we continued to invest in our future in 2003. We made unproved property purchases of $198 million and incurred geological and geophysical costs of $38 million and lease acquisition costs of $85 million.

During 2003, Chesapeake drilled 442 (352 net) operated wells and participated in another 641 (104 net) wells operated by other companies. Chesapeake's drilling costs were $438 million for operated wells and $140 million for non-operated wells. The company's success rate was 96% for operated wells and 95% for non-operated wells. Chesapeake has an active property consolidation program that is focused on corporate and property acquisitions of up to $500 million. During 2003, we acquired approximately 805 bcfe of proved reserves for a total cost of $1.1 billion (primarily in nine transactions of more than $10 million each). Pro forma for two large acquisitions completed in January 2004, we spent $1.5 billion to acquire 1,102 bcfe of proved reserves in 2003.

As of December 31, 2003, Chesapeake's estimated future net cash flows discounted at 10% before taxes (PV-10) were $7.33 billion using field differential adjusted prices of $30.22 per bo (based on a NYMEX year-end price of $32.47 per bo) and $5.68 per mcf (based on a NYMEX year-end price of $5.97 per mcf). PV-10 as of December 31, 2002 was $3.72 billion using field differential adjusted prices of $30.18 per bo (based on a NYMEX year-end price of $31.25 per bo) and $4.28 per mcf (based on a NYMEX year-end price of $4.60 per mcf). Pro forma for acquisitions completed in January 2004, our proved reserves at year-end 2003 were 3,474 bcfe and had a PV-10 value of $7.9 billion.

Chesapeake continues to focus on improving the strength of its balance sheet. At the beginning of the year, the company's total debt as a percentage of total capitalization (total capitalization is the sum of total debt and stockholders' equity) was 65% and debt per proved mcfe was $0.75 per mcfe. By year-end 2003 (pro forma for the reserves acquired in January 2004 and the related financings and debt exchanges completed in January 2004), the company's debt as a percentage of total capitalization had decreased to 53% and debt per proved mcfe had decreased to $0.65 per mcfe, reductions of 18% and 13%, respectively. Key goals of management are to reduce debt to below 50% of total capitalization and debt per mcfe of proved reserves to below $0.60.

Liquidity and Capital Resources

Sources of Liquidity and Uses of Funds

Our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for large acquisitions) is cash flow from operations. Based on our current production, price and expense assumptions, we expect cash flow from operations will exceed our drilling capital expenditures. Our budget for drilling, land and seismic activities during 2004 is currently between $750 million and $800 million. While we believe this level of exploration and development will be sufficient to increase our reserves in 2004 and achieve our target of a 20% increase in production over 2003 production (inclusive of acquisitions completed in January 2004), higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary. Any cash flow from operations not needed to fund our drilling program will be available for acquisitions, debt repayment or other general corporate purposes in 2004.

Cash provided by operating activities (exclusive of changes in assets and liabilities) was $903.9 million in 2003, compared to $412.5 million in 2002 and $518.6 million in 2001. The $491.4 million increase from 2002 to 2003 was primarily due to higher realized prices and higher volumes of oil and gas production. 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 produced. We expect that 2004 production volumes will be higher than in 2003 and that cash provided by operating activities in 2004 will exceed 2003 levels. While a precipitous decline in gas prices in 2004 would significantly affect the amount of cash flow that would be generated from operations, we have 78% of our expected oil production in 2004 hedged at an average NYMEX price of $28.68 per barrel of oil and 69% of our expected natural gas production in 2004 hedged at an average NYMEX price of $5.32

per mcf. This level of hedging provides certainty of the cash flow we will receive for a substantial portion of our 2004 production. Depending on changes in oil and gas futures markets and management's view of underlying oil and natural gas supply and demand trends, however, we may increase or decrease our current hedging positions.

Another source of liquidity is our $350 million revolving bank credit facility (with a committed borrowing base of $350 million) which matures in May 2007. At March 10, 2004, we had $_____ million of indebtedness under the bank credit facility. We use the facility to fund daily operating activities and acquisitions as needed. We borrowed and repaid $738.0 million in 2003 and $252.5 million in 2002, and we borrowed $433.5 million and repaid $458.5 million in 2001 under the facility. We incurred $2.5 million, $2.9 million and $6.6 million of financing costs related to the credit facility in 2003, 2002 and 2001, respectively, as a result of amendments to the credit facility agreement.

We believe that our available cash, cash provided by operating activities and funds available under our bank credit facility will be sufficient to fund our operating, interest and general and administrative expenses, our capital expenditure budget, our short-term contractual obligations and dividend payments at current levels for the foreseeable future.

The public markets have been our principal source of capital to finance large acquisitions. We have sold debt and equity in both public and private offerings in the past, and we expect that these sources of capital will continue to be available to us in the future for acquisitions. Nevertheless, we caution you that ready access to capital on reasonable terms and the availability of desirable acquisition targets at attractive prices are subject to many uncertainties, as explained under "Risk Factors" in Item 1—Business. The following table reflects the proceeds from sales of securities we issued in 2003, 2002 and 2001($ in millions):

	2003		2002		2001	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Unsecured senior notes guaranteed by subsidiaries	$ 500.0	$ 485.4	$ 450.0	$ 439.4	$ 1,050.0	$ 1,028.3
Convertible preferred stock	402.5	390.4	—	—	150.0	145.1
Common stock	186.3	177.4	172.5	164.1	—	—
Total	$ 1,088.8	$ 1,053.2	$ 622.5	$ 603.5	$ 1,200.0	$ 1,173.4

We used $27.3 million and $5.0 million to pay common stock dividends in 2003 and 2002, respectively, and we paid dividends of $20.9 million, $10.2 million and $1.1 million on our preferred stock in 2003, 2002 and 2001. We received $9.3 million, $3.8 million and $3.2 million from the exercise of employee and director stock options in 2003, 2002 and 2001, respectively. We used $2.1 million to purchase treasury stock in 2003 to be used for future employer matching contributions to the 401(k) plans.

Historically, we have used significant amounts of funds to purchase and retire outstanding company senior notes. In 2003, we purchased and subsequently retired $106.4 million of our 8.5% senior notes for $113.1 million, including redemption premium of $6.7 million. In 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. In 2001, we used $906.0 million to purchase or redeem various Chesapeake and Gothic senior notes. 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.

Cash used in investing activities increased to $2,077.2 million in 2003, compared to $779.7 million in 2002 and $670.1 million in 2001. The following table shows our capital expenditures during these years ($ in millions):

	2003	2002	2001
Exploration and development drilling	$ 727.2	$ 400.2	$ 421.0
Acquisitions of oil and gas properties and companies	1,261.3	331.7	316.7
Deposit for pending acquisitions	13.3	15.0	—
Investment in securities of other companies	30.8	2.4	40.2
Drilling rigs, plants and gathering systems	23.3	6.6	15.9
Office buildings and other administrative	49.4	30.6	23.1
Total	$ 2,105.3	$ 786.5	$ 816.9

Through divestitures of oil and gas properties, we received $22.2 million in 2003, $0.8 million in 2002 and $144.3 million, including $142.9 million for the sale of our Canadian subsidiary, in 2001. Sales of other assets and recoveries of investment in securities of other companies provided $5.8 million, $5.8 million and $3.2 million of cash in 2003, 2002 and 2001, respectively.

During 2003 and early 2004, we took several steps to improve our capital structure, including the transactions described below under *Investing and Financing Transactions*. These transactions enabled us to extend our average maturity of long-term debt to over nine years with an average interest rate of 7.7%. The company's debt as a percentage of total capitalization decreased to 53% (pro forma for January 2004 activity) and debt per proved mcfe decreased to $0.65 per mcfe. Reducing debt to below 50% of total capitalization and reducing debt per mcfe of proved reserves to below $0.60 are key goals of our business strategy.

Our accounts receivable are primarily from purchasers of oil and natural gas ($173.8 million at December 31, 2003) and exploration and production companies which own interests in properties we operate ($37.8 million at December 31, 2003). This 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.

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.

Investing and Financing Transactions

The following describes significant investing and financing transactions that we completed in 2003 and in January and February 2004:

Investments Transactions

First Quarter 2003

- Mid-Continent properties from a wholly-owned subsidiary of ONEOK, Inc., $296 million ($15 million paid in 2002)
- Anadarko Basin properties in western Oklahoma and Texas Panhandle from El Paso Corporation, for cash consideration of approximately $500 million
- Bray Field properties in southern Oklahoma from Vintage Petroleum, Inc, for cash consideration of approximately $29 million
- 5.3 million shares, or approximately 25%, of Pioneer Drilling Company common stock, for $20 million

Second Quarter 2003

- Arkoma Basin properties in eastern Oklahoma and western Arkansas from Oxley Petroleum Company for cash consideration of approximately $155 million

Third Quarter 2003

- Beckham County, Oklahoma properties, gathering system and gas treatment plant, for cash consideration of approximately $44.5 million
- 25% limited partnership interest in Eagle Energy Partnership I, L.P., a gas marketing company, for $5.8 million

Fourth Quarter 2003

- 20% limited partnership interest in Texas Vicksburg Holding L.P., which conducts E&P operations through several partnerships, $5.0 million
- South Texas properties from Laredo Energy, L.P. and its partners, for cash consideration of approximately $200 million
- Permian Basin properties, $23 million

January/February 2004

- Concho Resources Inc., Permian Basin and Mid-Continent properties, for cash consideration of approximately $420 million ($10 million paid in 2003)
- South Texas properties, for cash consideration for approximately $65 million ($3.3 million paid in 2003)

Financing Transactions

First Quarter 2003

- Private placement of $300 million 7.5% senior notes due 2013
- Public offering of 23 million shares of common stock at $8.10 per share

- Private placement of $230 million of 6.0% cumulative convertible preferred stock

Third Quarter 2003

- Privately negotiated exchange of $63.0 million of 7.75% senior notes due 2015 and $0.1 of accrued interest for $27.9 million of 8.375% senior notes due 2008 and $0.5 million accrued interest and $32.0 million of 8.5% senior notes due 2012 and $1.1 million of accrued interest

Fourth Quarter 2003

- Privately negotiated exchange of $23.7 million of 7.75% senior notes due 2015 and accrued interest of $0.4 million for $6.0 million of 8.375% senior notes due 2008 and $0.2 million of accrued interest and $16.8 million of 8.125% senior notes due 2011
- Privately negotiated exchange of $63.8 million of 7.5% senior notes due 2013 and accrued interest of $0.4 million for $54.9 million of 8.125% senior notes due 2011 and accrued interest of $0.2 million and $6.3 million of 8.375% senior notes due 2008 and accrued interest of $0.2 million
- Private placement of $200 million 6.875% senior notes due 2016
- Public offering of 1.725,000 shares of 5.0% convertible preferred stock at $100 per share
- Paid $113.1 million (including premium of $6.7 million) for $106.4 million of 8.5% senior notes due 2012 pursuant to cash tender offer

January and February 2004

- Public offering of 23 million shares of common stock at $13.51 per share
- Public exchange of $72.8 million of 7.75% senior notes due 2015 and $2.8 million accrued interest and additional $433.5 million of 6.875% senior notes due 2016 and $4.1 million of accrued interest for $458.5 million of 8.125% senior notes due 2011 and $10.8 million accrued interest
- Privately negotiated exchanges of $37.0 million of 6.875% senior notes due 2016 and $0.5 million of accrued interest for $24.3 million of 8.125% senior notes due 2011 and $0.7 million accrued interest and $9.1 million of 7.75% senior notes due 2015 and $0.1 million accrued interest

Contractual Obligations

We have a $350 million revolving bank credit facility (with a committed borrowing base of $350 million) which matures in May 2007. As of December 31, 2003, we had no outstanding borrowings under this facility and had utilized $35.8 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 our senior unsecured long-term debt rating. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to an annual commitment fee of 0.375%. 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, and create liens. 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, 2003, our current ratio was 1.6 to 1 and our fixed charge coverage ratio was 4.8 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 $25.0 million.

As of December 31, 2003, senior notes represented approximately $2.1 billion of our long-term debt and consisted of the following ($ in thousands):

7.875% senior notes due 2004	$ 42,137
8.375% senior notes due 2008	209,815
8.125% senior notes due 2011	728,255
9.0% senior notes due 2012	300,000
8.5% senior notes due 2012	4,290

7.5% senior notes due 2013	363,823
7.75% senior notes due 2015	236,691
6.875% senior notes due 2016	200,000
Discount on senior notes	(26,959)
Discount for interest rate swap and swaption	(339)
	$2,058,052

Following the debt exchanges which occurred in January and February 2004 and excluding the 7.875% senior notes which were paid in March 2004 and the 8.5% senior notes which were called for redemption in March 2004, our pro forma long-term debt as of December 31, 2003 consisted of the following:

8.375% senior notes due 2008	$ 209,815
8.125% senior notes due 2011	245,407
9.0% senior notes due 2012	300,000
7.5% senior notes due 2013	363,823
7.75% senior notes due 2015	300,408
6.875% senior notes due 2016	670,487
Discount on senior notes	(79,298)
Discount for interest rate swap and swaption	(339)
	$2,010,303

No scheduled principal payments are required on any of the senior notes until 2008, when $209.8 million is due. Debt ratings for the senior notes are Ba3 by Moody's Investor Service, BB- by Standard & Poor's Ratings Services and BB- by Fitch Ratings. Debt ratings for our secured bank credit facility are Ba2 by Moody's Investor Service, BBB- 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., Mayfield Processing, L.L.C. and MidCon Compression, L.P. 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%, 7.75%, 7.50% and 6.875% 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, 2003, we estimate that secured commercial bank indebtedness of approximately $1,237.3 million could have been incurred under the most restrictive indenture covenant. The indenture covenants do not apply to our marketing subsidiaries, Chesapeake Energy Marketing, Inc., Mayfield Processing, L.L.C. and MidCon Compression, L.P., which are our only unrestricted subsidiaries.

The table below summarizes our contractual obligations as of December 31, 2003 ($ in thousands):

Contractual Obligations	Payments Due By Period				
	Total	Less than 1 Year	1-2 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$2,085,011	$ 46,427	$ —	$ 209,815	$1,828,769
Capital lease obligations	—	—	—	—	—
Operating lease obligations	5,437	2,353	2,169	500	415
Purchase obligations	—	—	—	—	—
Standby letters of credit	36,358	36,358	—	—	—
Other long-term obligations	1,738	1,496	242	—	—
Total contractual cash obligations	$2,128,544	$ 86,634	$ 2,411	$ 210,315	$1,829,184

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, 2003, we were required to post $33.5 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.

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, including swaps, counter-swaps (locking in the value of certain swaps), cap-swaps, basis protection swaps and call options. Item 7A—Quantitative and Qualitative Disclosures About Market Risk contains a description of each of these instruments.

Hedging allows us to predict with greater certainty the effective prices we will receive for our hedged oil and gas production. We closely monitor the fair value of our hedging contracts and may elect to settle a contract prior to its scheduled maturity date in order to lock in a gain or loss. Commodity markets are volatile, and Chesapeake's hedging activity is dynamic.

Mark-to-market positions under oil and gas hedging contracts fluctuate with commodity prices. As described above under "Contractual Obligations", we may be required to deliver cash collateral or other assurances of performance if our payment obligations to our hedging counterparties exceed levels stated in our contracts.

Realized gains and losses from our oil and gas derivatives resulted in a net decrease in oil and gas sales of $17.4 million or $0.06 per mcfe in 2003, a net increase of $96.0 million or $0.53 per mcfe in 2002 and a net increase of $105.4 million or $0.65 per mcfe in 2001. Oil and gas sales also includes changes in the fair value of oil and gas derivatives that do not qualify as cash flow hedges under SFAS 133, as well as gains (losses) on ineffectiveness of instruments designated as cash flow hedges. Unrealized gains (losses) included in oil and gas sales in 2003, 2002 and 2001 were $10.5 million, ($87.3) million and $84.8 million, respectively. Included in these unrealized gains (losses) are gains (losses) on ineffectiveness of cash flow hedges of ($9.2) million in 2003, ($3.6) million in 2002 and $2.5 million in 2001.

Changes in the fair value of oil and gas derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of derivative contracts are recorded in accumulated other comprehensive income until the month of related production. These unrealized losses, net of related tax effects, totaled $20.3 million and $3.5 million as of December 31, 2003 and 2002, respectively. Based upon the market prices at December 31, 2003, we expect to transfer to earnings approximately $17.6 million of the balance in accumulated other comprehensive income during the next 12 months. A detailed explanation of accounting for oil and gas derivatives under SFAS 133 appears under "Application of Critical Accounting Policies-Hedging" elsewhere in this Item 7.

The fair value of our oil and gas derivative instruments are recorded on our consolidated balance sheet as assets or liabilities. The estimated fair values of our oil and gas derivative instruments as of December 31, 2003 and 2002 are provided below:

	December 31,	
	2003	2002
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price gas swaps	$ (44,794)	$ (21,523)
Fixed-price gas cap-swaps	(18,608)	(50,732)
Gas basis protection swaps	46,205	8,227
Fixed-price gas counter swaps	—	37,048
Gas call options	(17,876)	—
Fixed-price gas locked swaps	1,777	16,498
Fixed-price crude oil swaps	—	(1,799)
Fixed-price crude oil cap-swaps	(11,692)	(2,252)
Estimated fair value	$ 44,988)	$ (14,533)

As of December 31, 2003, we had hedged approximately 78% of our expected oil production and 69% of our expected natural gas production in 2004. In addition, hedging contracts were in place for approximately 27% of expected natural gas production in 2005, 11% in 2006 and 8% in 2007. Natural gas basis protection swaps extend to 2009. A detailed listing of our oil and gas derivatives by year of maturity is included in Item 7A—Quantitative and Qualitative Disclosures About Market Risk.

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

	December 31,		
	2003	2002	2001
	($ in thousands)		
Fair value of contracts outstanding, beginning of year	$ (14,533)	$ 157,309	$ (89,288)
Change in fair value of contracts during the period	(31,078)	(52,419)	351,989
Contracts realized or otherwise settled during the period	17,389	(96,046)	(105,392)
Fair value of new contracts when entered into during the period	(16,766)	(45,603)	—
Fair value of contracts when closed during the period	—	22,226	—
Fair value of contracts outstanding, end of year	$ (44,988)	$ (14,533)	$ 157,309

Interest Rate Hedging

We also utilize hedging strategies to manage the exposure our fixed-rate senior notes have to interest rate changes. By entering into interest rate swaps, we convert a portion of our fixed rate debt to floating rate debt. To the extent the interest rate swaps have been designated as fair value hedges, results are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement.

The following describes interest rate swap activity since 2002 ($ in thousands):

Date Initiated	Fair Value at December 31, 2003	Date Closed	Cash Settlement Received	Previously Recognized Income	2003 Interest Income	Interest Income to be Recognized
March 2002	$ —	July 2002	$ 7,500	$ 6,778	$ 599	$ 123
June 2002	—	July 2002	1,130	1,130	—	—
August 2003	870	January 2004	940	—	870	70
August 2003	1,292	January 2004	1,370	—	1,292	78

In April 2002, Chesapeake entered into a “swaption” with an unrelated counterparty with respect to its 8.5% senior notes due 2012. The notional amount of the swaption was $142.7 million, which was the principal amount then outstanding under the 8.5% senior notes. The 8.5% senior notes included a “call option” whereby Chesapeake may redeem the debt at declining redemption prices beginning in March 2004. Under the swaption, the counterparty received the option to elect whether or not to enter into an interest rate swap with Chesapeake in March 2004, and Chesapeake received $7.8 million. The interest rate swap, if executed by the counterparty, would require Chesapeake to pay a fixed rate of 8.5% while the counterparty pays Chesapeake a floating rate of 6 month LIBOR in arrears plus 0.75%. Additionally, if the counterparty elects to enter into the interest rate swap, it may also elect to force Chesapeake to settle the transaction at the then current value of the interest rate swap.

According to SFAS 133, a fair value hedge relationship exist between the embedded call option in the 8.5% senior notes and the swaption. The fair value of the swaption is recorded on the consolidated balance sheets as a liability, and the debt’s carrying amount is adjusted by the change in the fair value of the call option subsequent to the initiation of the swaption. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense.

During the third quarter 2003, we exchanged and subsequently retired $32.0 million of our 8.5% senior notes. The exchange of debt was treated as a modification rather than an extinguishment. Accordingly, the adjustment to the carrying value of the debt of $3.3 million related to the application of hedge accounting was reflected as a discount on the notes issued in the exchange transaction and will be amortized to interest expense using the effective interest method. During the fourth quarter 2003, we purchased and subsequently retired $106.4 million of the remaining $110.7 million of 8.5% senior notes pursuant to a tender offer and recorded a $12.0 million loss related to the removal of the fair value designation of the corresponding amount of the swaption. Temporary fluctuations in the fair value of the portion of the swaption no longer designated as a fair value hedge are recorded as adjustments to interest expense. We recorded a $3.3 million unrealized loss in interest expense during 2003 due to a decline in the fair value of the portion of the swapion no longer designated as a fair value hedge.

As of December 31, 2003, the remaining notional amount of the swaption designated as a fair value hedge was $4.3 million. We have recorded an adjustment to the carrying amount of the debt of $0.5 million which represents the temporary fluctuations in the fair value of the call option included in the $4.3 million principal amount of 8.5% senior notes. Since the inception of the swaption, we have recorded a change in the fair market value of the swaption from a $7.8 million liability to a $32.6 million liability, an increase of $24.8 million. We have recorded as additional interest expense $5.6 million to reflect ineffectiveness after giving effect to the removal of the designation of a portion of the swaption as a fair value hedge under SFAS 133 as described previously.

On February 27, 2004, Chesapeake and the counterparty agreed to extend the swap exercise date to April 15, 2004. If the interest rate swap is exercised, on each succeeding March 15, the counterparty may elect to terminate the swap and cause it to be settled at the then current value of the interest rate swap. We may elect to terminate the swap and cause it to be settled at the then current value of the interest rate swap at any time during the term of the swap. Cash payments related to the interest rate swap, if initiated, or as a result of cash settlement at termination, will be recorded as adjustments to interest expense.

Results of Operations

General. For the year ended December 31, 2003, Chesapeake had net income of $313.0 million, or $1.21 per diluted common share, on total revenues of $1,717.4 million. This compares to net income of $40.3 million, or $0.17 per diluted common share, on total revenues of $738.5 million during the year ended December 31, 2002, and 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. The 2003 net income includes, on a pre-tax basis, a $20.8 million loss on repurchased of debt, a $6.4 million provision for legal settlements, $4.0 million in net unrealized gains on oil and gas and interest rate derivatives and a $2.0 million impairment of our investment in Seven Seas Petroleum Inc. 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.

Oil and Gas Sales. During 2003, oil and gas sales were $1,296.8 million versus $568.2 million in 2002 and $820.3 million in 2001. In 2003, Chesapeake produced 268.4 bcfe at a weighted average price of $4.79 per mcfe, compared to 181.5 bcfe produced in 2002 at a weighted average price of $3.61 per mcfe, and 161.5 bcfe produced in 2001 at a weighted average price of $4.56 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). The increase in prices in 2003 resulted in an increase in revenue of $317.2 million and increased production resulted in a $313.6 million increase, for a total increase in revenues of $630.8 million (excluding unrealized gains or losses on oil and gas derivatives).

The change in oil and gas prices has a significant impact on our oil and gas revenues and cash flows. Assuming 2003 production levels, a change of $0.10 per mcf of gas produced would result in an increase or decrease in revenues and cash flow of approximately $24.0 million and $22.6 million, respectively, and a change of $1.00 per barrel of oil produced would result in an increase or decrease in revenues and cash flows of approximately $4.7 million and $4.4 million, respectively, without considering the effect of derivative activities.

For 2003, we realized an average price per barrel of oil of $25.85, compared to $25.22 in 2002 and $26.92 in 2001 (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $4.85, $3.54 and $4.56 in 2003, 2002 and 2001, respectively. Realized gains or losses from our oil and gas derivatives resulted in a net decrease in oil and gas revenues of $17.4 million or $0.06 per mcfe in 2003, a net increase of $96.0 million or $0.53 per mcfe in 2002 and a net increase of $105.4 million or $0.65 per mcfe in 2001.

The following table shows our production by region for 2003, 2002 and 2001:

	Years Ended December 31,					
	2003		2002		2001	
	mmcfe	Percent	mmcfe	Percent	mmcfe	Percent
Mid-Continent	233,559	87.0 %	147,348	81.2 %	116,133	71.9 %
South Texas and Texas Gulf Coast	23,322	8.7	23,264	12.8	27,531	17.1
Permian Basin	8,496	3.2	7,637	4.2	5,029	3.1
Williston Basin and Other	2,979	1.1	3,229	1.8	3,683	2.3
Canada	—	—	—	—	9,075	5.6
Total production	268,356	100.0 %	181,478	100.0 %	161,451	100.0%

Natural gas production represented approximately 90% of our total production volume on an equivalent basis in 2003, compared to 89% in 2002 and 89% 2001. The increase in production from 2001 through 2003 is due to the combination of organic production growth during the period as well as acquisitions completed in 2002 and 2003.

Oil and Gas Marketing Sales. Chesapeake realized $420.6 million in oil and gas marketing sales for third parties in 2003, with corresponding oil and gas marketing expenses of $410.3 million, for a net margin of $10.3 million. Sales for third parties include the sale of oil and gas from wells not operated by Chesapeake, as well as the sale of oil and gas from working interest owners other than Chesapeake in wells operated by Chesapeake. This compares to sales of $170.3 million and $148.7 million, expenses of $165.7 million and $144.4 million, and margins of $4.6 million and $4.3 million in 2002 and 2001, respectively. In 2003, Chesapeake realized an increase in volumes and prices related to oil and gas marketing sales. In 2002, the increase in volume was partially offset by a decrease in oil and gas prices.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $137.6 million in 2003, compared to $98.2 million and $75.4 million in 2002 and 2001, respectively. On a unit-of-production basis, production expenses were $0.51 per mcfe in 2003 compared to $0.54 and $0.47 per mcfe in 2002 and 2001, respectively. The decrease in costs on a per unit basis in 2003 is due primarily to lower production costs associated with properties acquired during the year and realization of efficiencies from higher scale of operations in the Mid-Continent region. The increase in 2002 was primarily due to higher field service costs and higher production costs associated with properties acquired during 2002. We expect that production expenses per mcfe in 2004 will range from $0.55 to $0.60.

Production Taxes. Production taxes were $77.9 million in 2003 compared to $30.1 million in 2002 and $33.0 million in 2001. On a unit-of-production basis, production taxes were $0.29, $0.17 and $0.20 per mcfe in 2003, 2002 and 2001, respectively. The increase in 2003 of $47.8 million was due to an increase in the average wellhead prices received for natural gas and the loss of certain Oklahoma severance tax exemptions. The decrease in 2002 of $2.9 million was due to a decrease 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 $0.28 to $0.32 in 2004 based on an assumption that oil and natural gas wellhead prices range from $4.50 to $5.00 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 $23.8 million in 2003, $17.6 million in 2002 and $14.4 million in 2001. The increase in 2003 and 2002 is the result of the company's growth related to the various acquisitions which occurred in 2003 and 2002. This growth has resulted in a substantial increase in employees and related costs. We anticipate that general and administrative expenses for 2004 will be between $0.10 and $0.11 per mcfe produced, which is approximately the same level as 2003.

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 $35.5 million, $24.3 million and $18.2 million of internal costs in 2003, 2002 and 2001, respectively, directly related to our oil and gas exploration and development efforts.

Provision for Legal Settlements. We have entered into a settlement agreement, effective December 31, 2003, to resolve a legal proceeding brought against us by certain royalty owners. Under the terms of the settlement, we will refund Oklahoma royalty owners $10.5 million, including interest. The refund amount includes $3.6 million relating to marketing fees which we have previously paid into court and charged to provision for legal settlements ($0.3 million in the first quarter 2003 and $3.3 million in 2002). In the third and fourth quarter 2003, we accrued an additional $7.2 million related to the settlement. A description of the settlement is included in note 4 of notes to consolidated financial statements.

At the beginning of 2002, we had a reserve of approximately $4 million for potential liability associated with a number of cases alleging the cessation of leases in the West Panhandle Field. During 2002, we reversed approximately $3 million of this accrued liability, and we reversed the remaining $0.8 million in 2003. As of December 31, 2003, there are no outstanding liabilities related to these cases.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties was $369.5 million, $221.2 million and $172.9 million during 2003, 2002 and 2001, 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 $1.38 (all domestic), $1.22 (all domestic) and $1.07 ($1.08 in U.S. and $0.90 in Canada) in 2003, 2002 and 2001, respectively. We expect the 2004 DD&A rate to be between $1.50 and $1.55 per mcfe produced. The increase in the average rate from 2001 to 2003 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 $16.8 million in 2003, compared to $14.0 million in 2002 and $8.7 million in 2001. The increases in 2003 and 2002 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 39 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to fifteen years. To the extent 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 2004 depreciation and amortization of other assets to be between $0.07 and $0.09 per mcfe produced.

Interest and Other Income. Interest and other income was $2.8 million, $7.3 million and $2.9 million in 2003, 2002 and 2001, respectively. The 2003 income consisted of $1.0 million of interest income, a $0.4 million loss on our equity investment in Pioneer Drilling Company, a $0.6 million gain on the final settlement of the sale of our Canadian subsidiary, and $1.6 million of miscellaneous income. The 2002 income consisted of $2.9 million in interest income, $2.9 million of interest accrued on our investment in Seven Seas, a $0.5 million gain on the sale of our investment in RAM notes, a $0.3 million loss on our investment in Petroleum Place and $1.3 million of miscellaneous income.

Interest Expense. Interest expense increased to $154.4 million in 2003, compared to $112.0 million in 2002 and $98.3 million in 2001. The increase in 2003 is due to a $517.7 million increase in average long-term borrowings in 2003 compared to

2002. The increase in 2002 is due to a $264 million increase in average long-term borrowings in 2002 compared to 2001. In addition to the interest expense reported, we capitalized $13.0 million of interest during 2003, compared to $5.0 million capitalized in 2002, and $4.7 million capitalized in 2001 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 2004 interest expense to be between $0.45 and $0.50 per mcfe produced.

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 2003 are a realized gain of $3.9 million related to interest rate derivatives and an unrealized loss on interest rate derivatives of $6.5 million. Included in interest expense in 2002 are a realized gain of $3.4 million related to interest rate derivatives and an unrealized loss on interest rate derivatives of $0.8 million. There were no such gains or losses in 2001. A detailed explanation of our interest rate hedging appears under the caption "Hedging Activities—Interest Rate Hedging" elsewhere in this item 7.

Loss on Investment 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. 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 in bankruptcy. In the third quarter of 2003, we received approximately $5.5 million in proceeds from the sale of its principal assets. Seven Seas reported in October 2003 that it had no source of additional cash flow and only contingent assets remaining, the value of which is highly speculative. Accordingly, in the fourth quarter, 2003 we determined that any remaining assets of Seven Seas would not be adequate for us to realize the remaining investment on our books. At that time, we recorded an impairment of $2.0 million which reduced the carrying value of our investment to zero.

Loss on Repurchases of Debt. During 2003, we purchased and subsequently retired $106.4 million of our 8.5% senior notes due 2012 for a total consideration of $114.9 million, including accrued interest of $1.8 million and $6.7 million of redemption premium. In connection with this repurchase transaction we recorded a pre-tax loss of $20.8 million, consisting of $6.7 million of redemption premium, $1.8 million write-off of unamortized debt issue costs and notes discount, $0.2 million of transaction costs, and a write-off of the call option value of $12.0 million carried as a discount on the 8.5% senior notes based on the hedging relationship between the notes and our 8.5% swaption. 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.

Provision (Benefit) for Income Taxes. Chesapeake recorded income tax expense of $191.8 million in 2003, compared to income tax expense of $26.9 million in 2002 and income tax expense of $144.3 million in 2001. All income tax expense for 2003 and 2002 was related to our domestic operations. The reason for the reduction in the effective tax rate of 40% in 2002 to 38% in 2003 was mainly due to more oil and gas sales in states that did not have income taxes. Income tax expense for 2001 was 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. 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. During 2003, we determined that it was more likely than not that an additional $4.4 million of the deferred tax assets related to Louisiana net operating losses will not be realized and we recorded an additional valuation allowance equal to such amounts.

Cumulative Effect of Accounting Change. Effective January 1, 2003, Chesapeake adopted SFAS No. 143, *Accounting For Asset Retirement Obligations*. Upon adoption of SFAS 143, we recorded the discounted fair value of our expected future obligations of $30.5 million, a cumulative effect of the change in accounting principle as an increase to earnings of $2.4 million (net of income taxes) and an increase in net oil and gas properties of $34.3 million.

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 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, 2003, 2002 and 2001, the net market value of our derivatives was a liability of $75.4 million, a liability of $44.7 million and an asset of $157.3 million, respectively. With respect to our derivatives held as of December 31, 2003, an increase or decrease in natural gas prices of $0.25 per mmbtu would decrease or increase the estimated fair value of our derivatives by approximately $86 million. An increase or decrease in crude oil prices of $1.00 per barrel would decrease or increase the estimated fair value of our derivatives by approximately $5 million.

Oil and Gas Properties. The accounting for our business is subject to special accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and gas business activities: the successful efforts method and the full-cost method. 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, 2003, approximately 74% 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 may 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 an increase or decrease 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 changes 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. Our oil and gas depreciation, depletion and amortization (DD&A)

rates have fluctuated between $0.75 per mcfe in 2000 to $1.38 per mcfe in 2003 reflecting the impact of changes in prices and finding costs during these periods. As of December 31, 2003, 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 3,169 bcfe by 2.7 bcfe and 1.0 bcfe, respectively, and would also reduce the company's present value of estimated future net revenues by approximately $144.9 million and $25.0 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.

The Emerging Issues Task Forces (EITF) is considering two issues related to the reporting of oil and gas mineral rights. Issue No. 04-02, *Whether Mineral Rights Are Tangible or Intangible Assets and Related Issues*, considers whether mineral rights are intangible assets pursuant to SFAS No. 141, *Business Combinations.* Issue No. 03-S, *Application of SFAS No. 142 Goodwill and Other Intangible Assets, to Oil and Gas Companies*, considers whether oil and gas drilling rights are subject to the classification and disclosure provisions of SFAS 142 if they are intangible assets.

Chesapeake classifies the cost of oil and gas mineral rights as property and equipment and believes that this is consistent with oil and gas accounting and industry practice. If the EITF determines that oil and gas mineral rights are intangible assets and are subject to the applicable classification and disclosure provisions of SFAS 142, we estimate that $227.3 million and $72.5 million would be classified on our consolidated balance sheets as "intangible undeveloped leasehold" and $1.4 billion and $532.2 million would be classified as "intangible developed leasehold" as of December 31, 2003 and 2002, respectively. These amounts are net of accumulated DD&A. There would be no effect on the consolidated statements of operations or cash flows as the intangible assets related to oil and gas mineral rights would continue to be amortized under the full cost method of accounting.

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.

Under SFAS No. 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.

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, 2003 we have a deferred tax asset of $194.9 million, of which only $6.8 million had an associated valuation allowance.

Accounting for Business Combinations. Our business has grown substantially through acquisitions and our business strategy is to continue to pursue acquisitions as opportunities arise. 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.

Disclosures About Effects of Transactions with Related Parties

As of December 31, 2003, we had accrued accounts receivable from our CEO and COO of $0.3 million and $2.6 million, respectively, representing billings from December 2003 which were paid in January 2004. Since Chesapeake was founded in 1989, our chief executive officer and chief operating officer have acquired small working interests in certain of our oil and gas properties by participating in our drilling activities. Joint interest billing accounts of the CEO and COO are settled in cash. Under their employment agreements, the CEO and COO are permitted to participate in all, or none, of the wells drilled by or on behalf of Chesapeake during each calendar quarter, but they are not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake’s board of directors 30 days prior to the start of a quarter. Their participation is permitted only under the terms outlined in their employment agreements, which, among other things, limit their individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake’s working interest would be reduced below 12.5% as a result of their participation.

In October 2001, we sold Chesapeake Canada Corporation, a wholly-owned subsidiary, for net proceeds of approximately $143.0 million. Our CEO and COO each received $2.0 million related to their fractional ownership interest in these Canadian assets, which they acquired and paid for pursuant to the terms of their employment agreements. The portion of the proceeds allocated to our CEO and COO was based upon the estimated fair values of the assets sold as determined by management and the independent members of our board of directors using a methodology similar to that used by Chesapeake for acquisitions of assets from disinterested third parties.

During 2003, 2002 and 2001, we paid legal fees of $2,123,000, $600,000, and $391,000, respectively, for legal services provided by a law firm of which a director is a member.

Recently Issued Accounting Standards

During 2002 and 2003, the Financial Accounting Standards Board issued the following Statements of Financial Accounting Standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In July 2002, the FASB issued SFAS No. 146, *Accounting For Costs Associated with Exit or Disposal Activities*. SFAS 146 is effective for exit or disposal activities initiated after December 31, 2002. We adopted this standard during the quarter ended March 31, 2003 and it did not have any impact on our financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation, or FIN 45 *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantee of Indebtedness of Others*. FIN 45 requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. FIN 45's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The guarantor's previous accounting for guarantees that were issued before the date of FIN 45's initial application may not be revised or restated to reflect the effect of the recognition and measurement provisions of the Interpretation. The disclosure requirements are effective for financial statements of both interim and annual periods that end after December 15, 2002. Chesapeake is not a guarantor under any significant guarantees and thus this interpretation is not expected to have a significant effect on the company's financial position or results of operations.

In March 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. SFAS 149 is effective for contracts entered into or modified after June 30, 2003. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. We adopted this standard during the quarter ended September 30, 2003 and it did not have any impact on our financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*. SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003 and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. This statement establishes new standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that an issuer classify a financial instrument that is within the scope of this statement as a liability because the financial instrument embodies an obligation of the issuer. This statement applies to certain forms of mandatorily redeemable financial instruments including certain types of preferred stock, written put options and forward contracts. Adoption of this standard did not have any significant impact on our financial position or results of operations.

In December 2003, the Securities and Exchange Commission issued Staff Accounting Bulletin 104, *Revenue Recognition*. SAB 104 revises or rescinds certain guidance included in previously issued staff accounting bulletins in order to make this interpretive guidance consistent with current authoritative accounting and auditing guidance and SEC rules and regulations relating to revenue recognition. This bulletin was effective immediately upon issuance. Chesapeake's current revenue recognition policies comply with SAB 104.

In January 2003, the FASB issued Financial Interpretation No. 46, *Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51* FIN 46 is an interpretation of Accounting Research Bulletin 51, "Consolidated Financial Statements," and addresses consolidation by business enterprises of variable interest entities (VIEs). The primary objective of FIN 46 is to provide guidance on the identification and financial reporting of entities over which control is achieved through means other than voting rights; such entities are known as VIEs, FIN 46 requires an enterprise to consolidate a VIE if that enterprise has a variable interest that will absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns, or both. An enterprise shall consider the rights and obligations conveyed by its variable interest in making this determination. At December 31, 2003, Chesapeake did not have any entities that would qualify for consolidation in accordance with the provisions of FIN 46, as amended. Therefore, the adoption of FIN 46, as amended, did not have an impact on our consolidated financial statements.

Forward-Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and gas reserve estimates, planned capital expenditures, the drilling of oil and gas wells and future acquisitions, expected oil and gas production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations, expected future expenses and utilization of net operating loss carryforwards. Statements concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1 and include:

- the volatility of oil and gas prices,
- our substantial indebtedness,
- the strength and financial resources of our competitors,
- the cost and availability of drilling and production services,
- our commodity price risk management activities, including counterparty contract performance risk,
- uncertainties inherent in estimating quantities of oil and gas reserves, projecting future rates of production and the timing of development expenditures,
- our ability to replace reserves,
- the availability of capital,
- uncertainties in evaluating oil and gas reserves of acquired properties and associated potential liabilities,
- Declines in the values of our oil and gas properties resulting in ceiling test write-downs,
- drilling and operating risks,
- our ability to generate future taxable income sufficient to utilize our NOLs before expiration,
- future ownership changes which could result in additional limitations to our NOLs,
- Adverse effects of governmental and environmental regulation,
- losses possible from pending or future litigation, and
- The loss of officers or key employees.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this and our other reports filed with the Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect our business.

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

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, 2003, our oil and gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps and call options. 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.
- For call options, Chesapeake receives a cash premium from the counterparty in exchange for the sale of a call option. If the floating price exceeds the fixed price of the call option, then Chesapeake pays the counterparty such excess. If the floating price settles below the fixed price of the call option, no payment is due from Chesapeake.

Chesapeake enters into counter-swaps from time to time for the purpose of locking in the value of a 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.

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.

In accordance with FASB Interpretation No. 39, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets, to the extent that a legal right of setoff exists.

Gains or losses from derivative transactions are reflected as adjustments to oil and gas sales on the consolidated statements 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 2003, 2002 and 2001 were $10.5 million, $(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 they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales. We recorded a gain (loss) on ineffectiveness of ($9.2) million, ($3.6) million and $2.5 million in 2003, 2002 and 2001, respectively.

As of December 31, 2003, we had the following open oil and gas derivative instruments designed to hedge a portion of our oil and gas production for periods after December 2003:

	Volume	Weighted Average Strike Price	Weighted Average Put Strike Price	Weighted Average Call Strike Price	Weighted Average Differential	SFAS 133 Hedge	Premiums Received	Fair Value at December 31, 2003 ($ in Thousands)
Natural Gas (mmbtu):								
Swaps:								
2004	171,120,000	5.31	—	—	—	Yes	$ —	$ (40,922)
2005	45,550,000	4.82	—	—	—	Yes	—	(8,507)
2006	25,550,000	4.74	—	—	—	Yes	—	678
2007	25,550,000	4.76	—	—	—	Yes	—	3,432
Basis Protection Swaps:								
2004	157,380,000	—	—	—	(0.17)	No	—	18,390
2005	109,500,000	—	—	—	(0.16)	No	—	11,042
2006	47,450,000	—	—	—	(0.16)	No	—	4,123
2007	63,875,000	—	—	—	(0.17)	No	—	5,280
2008	64,050,000	—	—	—	(0.17)	No	—	4,613
2009	36,500,000	—	—	—	(0.16)	No	—	2,757
Cap-Swaps:								
2004	29,320,000	5.31	3.75	—	—	No	—	(8,475)
2005	36,500,000	5.31	3.79	—	—	No	—	(9,015)
2006	7,300,000	5.36	3.75	—	—	No	—	(1,118)
Call Options:								
2004	60,760,000	—	—	6.30	—	No	16,766	(17,876)
Locked-Swaps:								
2004	—	—	—	—	—	No	—	2,302
Total Gas							16,766	(33,296)
Oil (bbls):								
Cap-Swaps:								
2004	4,516,000	28.68	21.76	—	—	No	—	(11,692)
Total Oil							—	(11,692)
Total Gas and Oil							$ 16,766	$ (44,988)

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties and subsequently evaluated internally using established index prices and other sources. The actual contribution to our future results of operations will be based on the market prices at the time of settlement and may be more or less than the fair value estimates used at December 31, 2003.

Based upon the market prices at December 31, 2003, we expect to transfer approximately $17.6 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, 2003 are expected to mature by December 31, 2007, with the exception of the basis protection swaps which extend through 2009.

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

	December 31, 2003	2002	2001
	($ in thousands)		
Fair value of contracts outstanding, beginning of year	$ (14,533)	$ 157,309	$ (89,288)
Change in fair value of contracts during the period	(31,078)	(52,419)	351,989
Contracts realized or otherwise settled during the period	17,389	(96,046)	(105,392)
Fair value of new contracts when entered into during the period	(16,766)	(45,603)	—
Fair value of contracts when closed during the period	—	22,226	—
Fair value of contracts outstanding, end of year	$ (44,988)	$ (14,533)	$ 157,309

The change in the fair value of our derivative instruments since January 1, 2003 resulted from an increase in market prices for natural gas and crude oil relative to the hedged price. Derivative instruments reflected as current in the consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and gas as of the consolidated balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. The fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity 2004	2005	2006	2007	2008	Thereafter	Total	Fair Value
					($ in millions)			
Liabilities:								
Long-term debt, including current portion — fixed rate	$42.1	$ —	$ —	$ —	$ 209.8	$1,833.1	$2,085.0(1)	$2,279.5
Average interest rate	7.9%	—	—	—	8.4%	8.0%	8.0%	8.0%

(1) This amount does not include the discount included in long-term debt of $27.0 million, the effect of interest rate swaps of $0.1 million and the effect of the swaption of ($ 0.5) million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving credit facility. All of our other long-term indebtedness is fixed rate and therefore does not expose us to the risk of earnings or cash flow loss due to changes in market interest rates. However, changes in interest rates do affect the fair value of our debt.

Interest Rate Hedging

We also utilize hedging strategies to manage the exposure our fixed-rate senior notes have to interest rate changes. By entering into interest rate swaps, we convert a portion of our fixed rate debt to floating rate debt. To the extent the interest rate swaps have been designated as fair value hedges, results are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement.

The following describes interest rate swap activity since 2002 ($ in thousands):

Date Initiated	Fair Value at December 31, 2003	Date Closed	Cash Settlement Received	Previously Recognized Income	2003 Interest Income	Remaining Interest Income
March 2002	$ —	July 2002	$ 7,500	$ 6,778	$ 599	$ 123
June 2002	—	July 2002	1.130	1,130	—	—
August 2003	870	January 2004	940	—	870	70
August 2003	1,292	January 2004	1,370	—	1,292	78

In April 2002, Chesapeake entered into a “swaption” with an unrelated counterparty with respect to its 8.5% senior notes due 2012. The notional amount of the swaption was $142.7 million, which was the principal amount then outstanding under the 8.5% senior notes. The 8.5% senior notes included a “call option” whereby Chesapeake may redeem the debt at declining redemption prices beginning in March 2004. Under the swaption, the counterparty received the option to elect whether or not to enter into an interest rate swap with Chesapeake in March 2004, and Chesapeake received $7.8 million. The interest rate swap, if executed by the counterparty, would require Chesapeake to pay a fixed rate of 8.5% while the counterparty pays Chesapeake a floating rate of 6 month LIBOR in arrears plus 0.75%. Additionally, if the counterparty elects to enter into the interest rate swap, it may also elect to force Chesapeake to settle the transaction at the then current value of the interest rate swap.

According to SFAS 133, a fair value hedge relationship exist between the embedded call option in the 8.5% senior notes and the swaption. The fair value of the swaption is recorded on the consolidated balance sheets as a liability, and the debt's carrying amount is adjusted by the change in the fair value of the call option subsequent to the initiation of the swaption. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense.

During the third quarter 2003, we exchanged and subsequently retired $32.0 million of our 8.5% senior notes. The exchange of debt was treated as a modification rather than an extinguishment. Accordingly, the adjustment to the carrying value of the debt of $3.3 million related to the application of hedge accounting was reflected as a discount on the notes issued in the exchange transaction and will be amortized to interest expense using the effective interest method. During the fourth quarter 2003, we purchased and subsequently retired $106.4 million of the remaining $110.7 million of 8.5% senior notes pursuant to a tender offer and recorded a $12.0 million loss related to the removal of the fair value designation of the corresponding amount of the swaption. Temporary fluctuations in the fair value of the portion of the swaption no longer designated as a fair value hedge are recorded as adjustments to interest expense. We recorded a $3.3 million unrealized loss in interest expense during 2003 due to a decline in the fair value of the portion of the swapion no longer designated as a fair value hedge.

As of December 31, 2003, the remaining notional amount of the swaption designated as a fair value hedge was $4.3 million. We have recorded an adjustment to the carrying amount of the debt of $0.5 million which represents the temporary fluctuations in the fair value of the call option included in the $4.3 million principal amount of 8.5% senior notes. Since the inception of the swaption, we have recorded a change in the fair market value of the swaption from a $7.8 million liability to a $32.6 million liability, an increase of $24.8 million. We have recorded as additional interest expense $5.6 million to reflect ineffectiveness after giving effect to the removal of the designation of a portion of the swaption as a fair value hedge under SFAS 133 as described previously.

On February 27, 2004, Chesapeake and the counterparty agreed to extend the swap exercise date to April 15, 2004. If the interest rate swap is exercised, on each succeeding March 15, the counterparty may elect to terminate the swap and cause it to be settled at the then current value of the interest rate swap. We may elect to terminate the swap and cause it to be settled at the then current value of the interest rate swap at any time during the term of the swap. Cash payments related to the interest rate swap, if initiated, or as a result of cash settlement at termination, will be recorded as adjustments to interest expense.

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

INDEX TO FINANCIAL STATEMENTS

CHESAPEAKE ENERGY CORPORATION

REPORT OF INDEPENDENT AUDITORS

To the Board of Directors and Shareholders
of Chesapeake Energy Corporation

In our opinion, the consolidated financial statements listed in the accompanying index appearing under Item 8 of the Form 10-K present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries (the "Company") at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule also listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, in 2001 the Company changed its method of accounting for its hedging activities as a result of adopting the provisions of Statement of Financial Accounting Standards No. 133 *"Accounting for Derivative Instruments and Hedging Activities"*.

As discussed in Note 12 to the consolidated financial statements, effective January 1, 2003, the Company changed the manner in which it accounts for asset retirement obligations.

PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma

February 29, 2004

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 40,581	$ 247,637
Restricted cash	—	82
Accounts receivable:		
Oil and gas sales	173,792	109,246
Joint interest, net of allowances of $2,669,000 and $1,433,000, respectively	37,789	22,760
Short-term derivatives	1,777	16,498
Related parties	2,983	2,155
Other	26,830	13,471
Deferred income tax asset	36,705	8,109
Short-term derivative instruments	2,690	—
Inventory and other	19,257	15,359
Total Current Assets	342,404	435,317
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	6,221,576	4,334,833
Unevaluated properties	227,331	72,506
Less: accumulated depreciation, depletion and amortization	(2,480,261)	(2,123,773)
	3,968,646	2,283,566
Other property and equipment	225,891	154,092
Less: accumulated depreciation and amortization	(61,420)	(47,774)
Total Property and Equipment	4,133,117	2,389,884
OTHER ASSETS:		
Long-term derivative instruments	17,493	2,666
Long-term investments	31,544	9,075
Other assets	47,733	38,666
Total Other Assets	96,770	50,407
TOTAL ASSETS	$ 4,572,291	$ 2,875,608
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 164,264	$ 86,001
Accrued interest	46,648	35,025
Short-term derivative instruments	92,651	33,697
Other accrued liabilities	108,020	56,465
Revenues and royalties due others	101,573	54,364
Total Current Liabilities	513,156	265,552
LONG-TERM LIABILITIES:		
Long-term debt, net	2,057,713	1,651,198
Revenues and royalties due others	13,921	13,797
Asset retirement obligation	48,812	—
Long-term derivative instruments	4,736	30,174
Deferred income tax liability	191,026	—
Other liabilities	10,117	7,012
Total Long-term Liabilities	2,326,325	1,702,181
CONTINGENCIES AND COMMITMENTS (Note 4)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, $.01 par value, 10,000,000 shares authorized:		
6.75% cumulative convertible preferred stock, 2,998,000 issued and outstanding at December 31, 2003 and 2002, entitled in liquidation to $149,900,000	149,900	149,900
6.00% cumulative convertible preferred stock, 4,600,000 and 0 shares issued and outstanding at December 31, 2003 and 2002, respectively, entitled in liquidation to $230,000,000	230,000	—
5.00% cumulative convertible preferred stock, 1,725,000 and 0 shares issued and outstanding at December 31, 2003 and 2002, respectively, entitled in liquidation to $172,500,000	172,500	—
Common Stock, $.01 par value, 350,000,000 shares authorized, 221,855,894 and 194,936,912 shares issued at December 31, 2003 and 2002, respectively	2,218	1,949
Paid-in capital	1,389,212	1,205,554
Accumulated deficit	(168,617)	(426,085)
Accumulated other comprehensive income (loss), net of tax of $12,449,000 and $2,307,000, respectively	(20,312)	(3,461)
Less: treasury stock, at cost; 5,071,571 and 4,792,529 common shares at December 31, 2003 and 2002, respectively	(22,091)	(19,982)
Total Stockholders' Equity	1,732,810	907,875
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 4,572,291	$ 2,875,608

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2003	2002	2001
	(in thousands, except per share data)		
REVENUES:			
Oil and gas sales	$ 1,296,822	$ 568,187	$ 820,318
Oil and gas marketing sales	420,610	170,315	148,733
Total Revenues	1,717,432	738,502	969,051
OPERATING COSTS:			
Production expenses	137,583	98,191	75,374
Production taxes	77,893	30,101	33,010
General and administrative	23,753	17,618	14,449
Oil and gas marketing expenses	410,288	165,736	144,373
Oil and gas depreciation, depletion and amortization	369,465	221,189	172,902
Depreciation and amortization of other assets	16,793	14,009	8,663
Provision for legal settlements	6,402	—	—
Total Operating Costs	1,042,177	546,844	448,771
INCOME FROM OPERATIONS	675,255	191,658	520,280
OTHER INCOME (EXPENSE):			
Interest and other income	2,827	7,340	2,877
Interest expense	(154,356)	(112,031)	(98,321)
Loss on investment in Seven Seas	(2,015)	(17,201)	—
Loss on repurchases of Chesapeake debt	(20,759)	(2,626)	(76,667)
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)	(174,303)	(124,518)	(158,582)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	500,952	67,140	361,698
INCOME TAX EXPENSE:			
Current	5,000	(1,822)	3,565
Deferred	185,360	28,676	140,727
Total Income Tax Expense	190,360	26,854	144,292
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	310,592	40,286	217,406
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF INCOME TAXES OF $1,464,000	2,389	—	—
NET INCOME	312,981	40,286	217,406
PREFERRED STOCK DIVIDENDS	(22,469)	(10,117)	(2,050)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 290,512	$ 30,169	$ 215,356
EARNINGS PER COMMON SHARE – BASIC:			
Income before cumulative effect of accounting change	$ 1.36	$ 0.18	$ 1.33
Cumulative effect of accounting change	0.02	—	—
Net Income	$ 1.38	$ 0.18	$ 1.33
EARNINGS PER COMMON SHARE – ASSUMING DILUTION:			
Income before cumulative effect of accounting change	$ 1.20	$ 0.17	$ 1.25
Cumulative effect of accounting change	0.01	—	—
Net Income	$ 1.21	$ 0.17	$ 1.25
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):			
Basic	211,203	166,910	162,362
Assuming dilution	258,567	172,714	173,981

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2003	2002	2001
	($ in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME	$ 312,981	$ 40,286	$ 217,406
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	382,004	230,236	177,543
Deferred income taxes	186,664	28,676	138,831
Loss on repurchases of Chesapeake debt	20,759	2,626	76,667
Amortization of loan costs and bond discount	5,861	6,041	5,084
Unrealized (gains) losses on derivatives	(3,992)	88,018	(84,789)
Cumulative effect of accounting changes	(3,853)	—	—
Loss on investment in Seven Seas	2,015	17,201	—
Impairment of investments	—	—	10,079
Gain on sale of Canadian subsidiary	—	—	(27,000)
Write-off of credit facility costs	—	—	3,392
Other	1,490	(567)	1,350
Cash provided by operating activities before changes in assets and liabilities	903,929	412,517	518,563
CHANGES IN ASSETS AND LIABILITIES:			
(Increase) decrease in accounts receivable	(72,683)	(44,966)	34,265
(Increase) decrease in inventory and other assets	(10,971)	11,330	929
Increase (decrease) in accounts payable, accrued liabilities and other	86,861	23,223	2,454
Increase (decrease) in current and non-current revenues and royalties due others	38,466	30,427	(2,474)
Changes in assets and liabilities	41,673	20,014	35,174
Cash provided by operating activities	945,602	432,531	553,737
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of oil and gas companies, proved properties and unproved properties, net of cash acquired	(1,261,275)	(331,651)	(316,743)
Exploration and development of oil and gas properties	(727,231)	(400,180)	(420,969)
Additions to buildings and other fixed assets	(71,454)	(33,559)	(24,853)
Additions to long-term investments	(30,750)	(2,408)	(40,239)
Divestitures of oil and gas properties	22,156	839	1,432
Deposits for Concho, South Texas Assets and ONEOK acquisitions	(13,250)	(15,000)	—
Sale of non-oil and gas assets and recoveries of investments	5,799	5,774	3,204
Additions to drilling rig equipment	(1,221)	(3,551)	(14,145)
Sale of Canadian subsidiary	—	—	142,906
Other	9	(9)	(698)
Cash used in investing activities	(2,077,217)	(779,745)	(670,105)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	738,000	252,500	433,500
Payments on long-term borrowings	(738,000)	(252,500)	(458,500)
Cash received from issuance of senior notes, net of offering costs	485,445	439,427	1,028,275
Proceeds from issuance of preferred stock, net of offering costs	390,365	—	145,086
Proceeds from issuance of common stock, net of offering costs	177,427	164,104	—
Cash paid to purchase senior notes, including redemption premium	(113,074)	(111,597)	(906,021)
Cash paid for common stock dividend	(27,253)	(4,987)	—
Cash paid for preferred stock dividend	(20,916)	(10,177)	(1,092)
Cash paid for financing cost of credit facilities	(2,474)	(2,902)	(6,611)
Cash paid for treasury stock and preferred stock	(2,109)	—	(10)
Net increase in outstanding payments in excess of cash balance	28,315	—	—
Other financing costs	(496)	(421)	—
Cash received (paid) in settlements of make-whole provisions	—	—	(3,336)
Cash received from exercise of stock options	9,329	3,810	3,216
Cash provided by financing activities	924,559	477,257	234,507
EFFECT OF EXCHANGE RATE CHANGES ON CASH	—	—	(545)
Net increase (decrease) in cash and cash equivalents	(207,056)	130,043	117,594
Cash and cash equivalents, beginning of period	247,637	117,594	—
Cash and cash equivalents, end of period	$ 40,581	$ 247,637	$ 117,594

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS —(Continued)

	Years Ended December 31,		
	2003	2002	2001
	($ in thousands)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$137,146	$105,671	$ 97,832
Income taxes, net of refunds received	$ 5,160	$ (738)	$ 5,461
DETAILS OF ACQUISITION OF GOTHIC ENERGY CORPORATION:			
Fair value of properties acquired	$ —	$ —	$ 371,371
Stock issued (13,553,276 shares)	$ —	$ —	$ (28,000)
Gothic preferred and common stock held by Chesapeake	$ —	$ —	$ (10,000)
Debt assumed	$ —	$ —	$(331,255)
Acquisition costs and other	$ —	$ —	$ (2,116)

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

In 2003, we issued $86.7 million of our 7.75% senior notes due 2015, $63.8 million of our 7.50% senior notes due 2013 and accrued interest of $1.0 million in exchange for $71.7 million of our 8.125% senior notes due 2011, $40.2 million of our 8.375% senior notes due 2008, $32.0 million of our 8.5% senior notes due 2012 and $2.2 million of our accrued interest, pursuant to privately negotiated transactions. The $71.7 million of our 8.125% senior notes, $40.2 of our 8.375% senior notes and $32.0 million of our 8.5% senior notes were retired upon receipt.

As of December 31, 2003, 2002 and 2001 dividends payable on our common and preferred stock were $15.7 million, $8.2 million, and $0, respectively.

During 2003, 2002 and 2001, $18.1 million, $1 million, and $13.3 million, respectively, of additions to oil and gas properties were recorded as an increase to accrued exploration and development costs.

In January 2003, Chesapeake adopted SFAS 143, *Accounting For Asset Retirement Obligation.* As a result, during the year ended December 31, 2003, we recorded non-cash additions to net oil and gas properties of $49.5 million.

In 2002, holders of our 6.75% cumulative convertible preferred stock converted 2,000 shares into 12,987 shares of common stock (at a conversion price of $7.70 per share).

In 2001, holders of our 7% cumulative convertible preferred stock converted 622,768 shares into 4,480,171 shares of common stock (at a conversion price of $6.95 per share), and we redeemed the remaining 1,269 shares of preferred stock for 7,239 shares of common stock and $3,000 of cash (at a redemption price of $52.45 per share, paid in 5.7 shares of common stock and cash of $2.45).

In 2001, Chesapeake completed the acquisition of Gothic Energy Corporation. We issued 3,989,813 shares of Chesapeake common stock to Gothic shareholders (other than Chesapeake).

In 2001, we issued 1,117,216 shares of Chesapeake common stock in exchange for 49.5% of RAM Energy, Inc.'s outstanding common stock. Chesapeake shares were valued at $8.854 per share. Subsequently, we made a make-whole payment to the former RAM shareholders of $3.3 million.

In 2001, Chesapeake purchased certain oil and gas assets from RAM Energy, Inc. for a total consideration of $74.4 million, consisting of $61.7 million of cash, surrender of $11.5 million principal amount of our RAM notes including $0.4 million in accrued interest, and cancellation of a $1.2 million receivable by us from RAM.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Years Ended December 31,		
	2003	2002	2001
	($ in thousands)		
PREFERRED STOCK:			
Balance, beginning of period	$ 149,900	$ 150,000	$ 31,202
Issuance of 6.00% cumulative convertible preferred stock	230,000	—	—
Issuance of 5.00% cumulative convertible preferred stock	172,500	—	—
Exchange of common stock for 2,000 and 624,037 shares of preferred stock	—	(100)	(31,202)
Issuance of 6.75% cumulative convertible preferred stock	—	—	150,000
Balance, end of period	552,400	149,900	150,000
COMMON STOCK:			
Balance, beginning of period	1,949	1,696	1,578
Exercise of stock options and warrants	39	23	21
Issuance of 23,000,000 shares of common stock	230	230	—
Issuance of 3,989,813 shares of common stock to Gothic shareholders	—	—	40
Issuance of 1,117,216 shares of common stock to RAM Energy, Inc. shareholders	—	—	11
Exchange of 4,487,410 shares of common stock for preferred stock	—	—	45
Other	—	—	1
Balance, end of period	2,218	1,949	1,696
PAID-IN CAPITAL:			
Balance, beginning of period	1,205,554	1,035,156	963,584
Exercise of stock options and warrants	9,290	3,787	3,188
Issuance of common stock	186,070	172,270	—
Issuance of common stock to acquire RAM Energy, Inc. common stock	—	—	9,881
Issuance of common stock to acquire Gothic Energy Corporation	—	—	29,389
Offering expenses	(21,139)	(8,506)	(4,891)
Exchange of 12,987 and 4,487,410 shares of common stock for preferred stock	—	100	31,157
Make-whole payments on common stock issued to RAM Energy, Inc. shareholders	—	—	(3,336)
Compensation costs related to stock and stock options	2,292	356	800
Tax benefit from exercise of stock options	7,145	2,391	5,384
Balance, end of period	1,389,212	1,205,554	1,035,156
ACCUMULATED DEFICIT:			
Balance, beginning of period	(426,085)	(442,974)	(659,286)
Net income	312,981	40,286	217,406
Dividends on common stock	(29,128)	(10,690)	—
Dividends on preferred stock	(26,385)	(12,707)	(1,094)
Balance, end of period	(168,617)	(426,085)	(442,974)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(3,461)	43,511	(3,901)
Foreign currency translation adjustments	—	—	(3,551)
Transfer of translation adjustments related to sale of Canadian subsidiary	—	—	7,452
Gain/(loss) on hedging activity	(16,851)	(46,972)	43,511
Balance, end of period	(20,312)	(3,461)	43,511
TREASURY STOCK—COMMON:			
Balance, beginning of period	(19,982)	(19,982)	(19,945)
Exercised options	—	—	(37)
Purchase of 279,042 shares of treasury stock	(2,109)	—	—
Balance, end of period	(22,091)	(19,982)	(19,982)
TOTAL STOCKHOLDERS' EQUITY	$ 1,732,810	$ 907,875	$ 767,407

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2003	2002	2001
		($ in thousands)	
NET INCOME	$ 312,981	$ 40,286	$ 217,406
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of ($15,272), ($18,027) and $98,140	(24,917)	(27,041)	147,210
Reclassification of (gain) loss on settled contracts, net of income taxes of $1,448, ($14,711) and ($32,415)	2,363	(22,066)	(48,623)
Ineffective portion of derivatives qualifying for hedge accounting, net of income taxes of $3,495, $1,423 and ($1,002)	5,703	2,135	(1,503)
Foreign currency translation adjustments, net of income taxes of ($2,367)	—	—	(3,551)
Transfer of translation adjustments related to sale of Canadian subsidiary, net of income taxes of $4,968	—	—	7,452
Cumulative effect of accounting change for financial derivatives, net of income taxes of ($35,715)	—	—	(53,573)
Comprehensive income (loss)	$ 296,130	$ (6,686)	$ 264,818

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation is an oil and natural gas exploration and production company engaged in the acquisition, exploration, and development of properties for the production of crude oil and natural gas from underground reservoirs and the marketing of natural gas and oil for other working interest owners in properties we operate. Our properties are located in Oklahoma, Texas, Arkansas, Louisiana, Kansas, Montana, Colorado, North Dakota and New Mexico.

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake Energy Corporation include the accounts of our direct and indirect wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. Investments in companies and partnerships which give us significant influence, but not control, over the investee are accounted for using the equity method. Other investments are generally carried at cost.

Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

Cash Equivalents

For purposes of the consolidated financial statements, Chesapeake considers investments in all highly liquid instruments with maturities of three months or less at date of purchase to be cash equivalents.

Restricted Cash

Chesapeake classifies cash balances as restricted cash when cash is restricted as to withdrawal or usage. The restricted cash balance at December 31, 2003 and 2002 was $0 and $82,000 respectively.

Inventory

Inventory, which is included in current assets, consists primarily of tubular goods and other lease and well equipment which we plan to utilize in our ongoing exploration and development activities and is carried at the lower of cost or market using the specific identification method. Oil inventory in tanks is carried at the lower of the estimated cost to produce or market value.

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 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 (see note 11). Capitalized costs are amortized on a composite unit-of-production method based on proved oil and gas reserves. As of December 31, 2003, approximately 74% 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 evaluate all properties quarterly. The average composite rates used for depreciation, depletion and amortization were $1.38 (U.S.) per equivalent mcfe in 2003, $1.22 (U.S.) per equivalent mcfe in 2002, and $1.07 ($1.08 in U.S. and $0.90 in Canada) per equivalent mcfe in 2001.

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 prospect 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. Under these rules, 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.

Leasehold Costs

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.

The Emerging Issues Task Forces (EITF) is considering two issues related to the reporting of oil and gas mineral rights. Issue No. 04-02, *Whether Mineral Rights Are Tangible or Intangible Assets and Related Issues*, considers whether mineral rights are intangible assets pursuant to SFAS No. 141, *Business Combinations.* Issue No. 03-S, *Application of SFAS No. 142 Goodwill and Other Intangible Assets, to Oil and Gas Companies*, considers whether oil and gas drilling rights are subject to the classification and disclosure provisions of SFAS 142 if they are intangible assets.

Chesapeake classifies the cost of oil and gas mineral rights as property and equipment and believes that this is consistent with oil and gas accounting and industry practice. If the EITF determines that oil and gas mineral rights are intangible assets and are subject to the applicable classification and disclosure provisions of SFAS 142, we estimate that $227.3 million and $72.5 million would be classified on our consolidated balance sheets as "intangible undeveloped leasehold" and $1.4 billion and $532.2 million would be classified as "intangible developed leasehold" as of December 31, 2003 and 2002, respectively. These amounts are net of accumulated DD&A. There would be no effect on the consolidated statements of operations or cash flows as the intangible assets related to oil and gas mineral rights would continue to be amortized under the full cost method of accounting.

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.

Asset Retirement Obligations

Effective January 1, 2003, Chesapeake adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets.

SFAS 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For oil and gas properties, this is the period in which an oil or gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is reversed.

Other Property and Equipment

Other property and equipment consists primarily of gas gathering and processing facilities, drilling rigs, vehicles, land, office buildings and equipment, and software. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. The costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from the accounts, and the resulting gain or loss is reflected in operations. Other property and equipment costs are depreciated on a straight-line basis. A summary of other property and equipment and the useful lives are as follows:

	December 31,		
	2003	**2002**	**Useful Life**
	(in thousands)		**(in years)**
Land	$ 11,777	$ 9,000	-
Buildings and improvements	74,272	50,269	15 – 39
Gathering, processing and compression equipment	58,083	30,818	7 – 15

Other fixtures and equipment	55,477	38,943	2 – 7
Drilling rigs	26,282	25,062	15
Total	$ 225,891	$ 154,092	

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and costs associated with our revolving bank credit facility. The remaining unamortized debt issue costs at December 31, 2003 and 2002 totaled $28.4 million and $21.5 million, respectively, and are being amortized over the life of the senior notes or revolving credit facility.

Capitalized Interest

During 2003, 2002 and 2001, interest of approximately $13.0 million, $5.0 million and $4.7 million, respectively, was capitalized 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.

Income Taxes

Chesapeake has adopted Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. SFAS 109 requires deferred tax liabilities or assets to be recognized for the anticipated future tax effects of temporary differences that arise as a result of the differences in the carrying amounts and the tax bases of assets and liabilities.

Net Income (Loss) Per Share

Statement of Financial Accounting Standards No. 128, *Earnings Per Share*, requires presentation of “basic” and “diluted” earnings per share, as defined, on the face of the statements of operations for all entities with complex capital structures. SFAS 128 requires a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

The following securities were not included in the calculation of diluted earnings per share, as the effect was antidilutive:

- For the years ended December 31, 2003, 2002 and 2001, outstanding warrants to purchase 0.4 million, 0.6 million and 1.1 million shares of common stock at a weighted average exercise price of $14.55, $14.51 and $12.61, respectively, were antidilutive because the exercise prices of the warrants were greater than the average market price of the common stock.
- For the years ended December 31, 2003, 2002 and 2001, outstanding options to purchase 1.9 million, 0.6 million and 0.3 million shares of common stock at a weighted average exercise price of $11.15, $11.93 and $15.54, respectively, were antidilutive because the exercise prices of the options were greater than the average market price of the common stock.
- For the year ended December 31, 2002, diluted shares do not include the assumed conversion of the outstanding 6.75% preferred stock (convertible into 19.5 million common shares), and the common stock equivalent of preferred stock outstanding prior to conversion (convertible into 5,693 shares) as the effects were antidilutive.

A reconciliation for the years ended December 31, 2003, 2002 and 2001 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Year Ended December 31, 2003:			
Income before cumulative effect of accounting change, net of tax	$ 310,592		
Preferred dividends	(22,469)		
Basic EPS Income available to common shareholders before cumulative effect of accounting change, net of tax	$ 288,123	—	$ 1.36
Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.00% convertible preferred stock	—	1,441	
Common shares assumed issued for 6.00% convertible preferred stock	—	18,499	
Common shares assumed issued for 6.75% convertible preferred stock	—	19,467	
Preferred dividends	22,469	—	
Employee stock options	—	7,957	
Diluted EPS Income available to common shareholders before cumulative effect of accounting change, net of tax	$ 310,5921	258,567	$ 1.20
For the Year Ended December 31, 2002:			
Basic EPS Income available to common shareholders	$ 30,169	166,910	$ 0.18
Effect of Dilutive Securities			
Employee stock options	—	5,797	
Warrants assumed in Gothic acquisition	—	7	
Diluted EPS Income available to common shareholders	$ 30,169	172,714	$ 0.17
For the Year Ended December 31, 2001:			
Basic EPS Income available to common shareholders	$ 215,356	162,362	$ 1.33
Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of preferred shares exchanged during the period:			
Common shares assumed issued for 6.75% convertible preferred stock	—	2,989	
Common shares assumed issued prior to conversion for 7% convertible preferred stock	—	1,464	
Preferred stock dividends	2,050	—	
Employee stock options	—	7,160	
Warrants assumed in Gothic acquisition	—	6	
Diluted EPS Income available to common shareholders	$ 217,406	173,981	$ 1.25

On January 14, 2004, we issued 23,000,000 shares of common stock at a price to the public of $13.51 per share.

On November 12, 2003, we issued 1,725,000 shares of 5.00% cumulative convertible preferred stock, par value $0.01 per share and liquidation preference $100 per share, in a public offering.

On March 5, 2003, we issued 4,600,000 shares of 6.00% cumulative convertible preferred stock, par value $0.01 per share and liquidation preference $50 per share, in a private offering. We subsequently registered, under the Securities Act of 1933, the shares of the preferred stock and underlying common stock for resale by the holder.

On March 5, 2003, we issued 23,000,000 shares of Chesapeake common stock at $8.10 per share in a public offering for proceeds of $177.4 million.

On November 13, 2001, we issued 3,000,000 shares of 6.75% cumulative convertible preferred stock, par value $0.01 per share and liquidation preference $50 per share, in a private offering. As of December 31, 2003, 2,998,000 shares remain outstanding. We subsequently registered, under the Securities Act of 1933, the shares of the preferred stock and underlying common stock for resale by the holders.

In 2001, holders of our 7% cumulative convertible preferred stock converted 622,768 shares into 4,480,171 shares of common stock (at a conversion price of $6.95 per share), and we redeemed the remaining 1,269 shares of 7% preferred stock for 7,239 shares of common stock and $3,000 of cash (at a redemption price of $52.45 per share, paid in 5.7 shares of common stock and cash of $2.45).

Revenue Recognition

Gas Imbalances. We follow the "sales method" of accounting for our gas revenue whereby we recognize sales revenue on all gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset and a liability is recognized to the extent that we have an imbalance in excess of the remaining gas reserves on the underlying properties. The gas imbalance asset and liability at December 31, 2003 and 2002 were not significant.

Oil and Natural Gas Sales. Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties.

Marketing Sales. Chesapeake takes title to the natural gas it purchases from other working interest owners in operated wells and arranges for transportation and delivers the natural gas to third parties, at which time revenues are recorded. Chesapeake's results of operations related to its oil and gas marketing activities are presented on a "gross" basis, because we act as a principal rather than an agent. All significant intercompany accounts and transactions have been eliminated. Only sales to third parties are reflected in the consolidated statements of operations.

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 transactions 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 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. Cash flows from derivative instruments are classified in the same category within the statement of cash flows as the items being hedged, or on a basis consistent with the nature of the instrument.

We have established the fair value of all derivative instruments using estimates determined by our counterparties and 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.

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.

Adoption of SFAS 133 at January 1, 2001 resulted in the recognition of $9.3 million of current derivative assets and $98.6 million in current derivative liabilities. The cumulative effect of the accounting change decreased accumulated other comprehensive income by $53.6 million, net of income tax, but did not have an effect on our net income or earnings per share amounts.

Accounts Payable and Accrued Liabilities

Included in accounts payable at December 31, 2003 are liabilities of approximately $28.3 million representing the amount by which checks issued, but not presented to our banks for collection, exceeded balances in applicable bank accounts. Other accrued liabilities include $34.1 million and $16.0 million of accrued drilling costs as of December 31, 2003 and 2002, respectively.

Currency Translation

The results of operations for non-U.S. subsidiaries are translated from local currencies into U.S. dollars using average exchange rates during each period; assets and liabilities are translated using exchange rates at the end of each period. Adjustments resulting from the translation process are reported in a separate component of stockholders' equity, and are not included in the determination of the results of operations. In October 2001, we sold our Canadian subsidiary. As a result, all translation adjustments related to our investment in this subsidiary were reclassified to earnings in the fourth quarter of 2001.

Stock Options

Chesapeake has elected to follow APB No. 25, *Accounting for Stock Issued to Employees* and related interpretations in accounting for its employee stock options. Under APB No. 25, compensation expense is recognized for the difference between the option price and market value on the measurement date. In March 2000, the Financial Accounting Standards Board issued FASB Interpretation No. 44 (FIN 44), which provided clarification regarding the application of APB No. 25. FIN 44 specifically addressed the accounting consequence of various modifications to the terms of a previously granted fixed-price stock option. Pursuant to FIN 44, we recognized compensation expense of $0.9 million, $0.4 million and $0.8 million in 2003, 2002, and 2001, respectively, as a result of modifications to fixed-price stock options that were made during the years ended December 31, 2003, 2001 and 2000. No compensation expense has been recognized for stock options upon original issuance in 2003, 2002 or 2001 because the exercise price of the stock options granted under the plans equaled the market price of the underlying stock on the date of grant.

Pro forma information regarding net income and earnings per share is required by SFAS No. 123 and has been determined as if we had accounted for our employee stock options under the fair value method of the statement. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted-average assumptions for 2003, 2002 and 2001, respectively: interest rates (zero-coupon U.S. government issues with a remaining life equal to the expected term of the options) ranging from 2.24% to 4.97%, dividend yields ranging from 0.0% to 1.55% , and volatility factors of the expected market price of our common stock ranging from 0.35 to 0.58. We used a weighted-average expected life of the options of five years for each of 2003, 2002 and 2001.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because our employee stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion the existing models do not necessarily provide a reliable single measure of the fair value of the company's employee stock options.

Pro forma information applying the fair value method follows:

	Years Ended December 31,		
	2003	2002	2001
	($ in thousands, except per share amounts)		
Net Income:			
As reported	$ 312,981	$ 40,286	$ 217,406
Less compensation expense, net of tax(1)	11,018	8,644	9,063
Pro forma	$ 301,963	$ 31,642	$ 208,343
Basic Earnings per common share:			
As reported	$ 1.38	$ 0.18	$ 1.33
Less compensation expense, net of tax(1)	0.06	0.05	0.06
Pro forma	$ 1 .32	$ 0.13	$ 1.27
Diluted Earnings per common share:			
As reported	$ 1.21	$ 0.17	$ 1.25
Less compensation expense, net of tax(1)	0.04	0.05	0.05
Pro forma	$ 1.17	$ 0.12	$ 1.20

(1) Adjustments are net of compensation expenses related to FIN 44 of $0.9 million, $0.4 million and $0.8 million in 2003, 2002 and 2001, respectively.

For purposes of the pro forma disclosures, the estimated fair value of the options is amortized to expense over the options' vesting period, which is four years. The above pro forma disclosures may not to be representative of the effects on pro forma net income for future years.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2002 and 2001 to conform to the presentation used for the 2003 consolidated financial statements.

2. Senior Notes

On November 26, 2003, we issued $200.0 million principal amount of 6.875% senior notes due 2016 in a private placement.

On March 5, 2003, we issued $300.0 million principal amount of 7.50% senior notes due 2013, which were exchanged on November 5, 2003 for substantially identical notes registered under the Securities Act of 1933**.** On October 17, 2003, we issued an additional $63.8 million of our 7.50% senior notes due 2013 and accrued interest of $0.4 million in exchange for $54.9 million of our 8.125% senior notes due 2011, $6.3 million of our 8.375% senior notes due 2008 and accrued interest of $0.4 million, pursuant to a privately negotiated transaction. The $54.9 million of 8.125% senior notes and $6.3 million of 8.375% senior notes were retired upon receipt.

On December 20, 2002, we issued $150.0 million principal amount of 7.75% senior notes due 2015, which were exchanged on February 20, 2003 for substantially identical notes registered under the Securities Act of 1933. On July 16, 2003, we issued an additional $29.5 million of our 7.75% senior notes due 2015 in exchange for $27.9 million of our 8.375% senior notes due 2008 and $0.5 million of accrued interest, pursuant to a privately negotiated transaction. The $27.9 million of 8.375% senior notes due 2008 were retired upon receipt. On August 5, 2003, we issued an additional $33.5 million of our 7.75% senior notes due 2015 and accrued interest of $0.1 million in exchange for $32.0 million of our 8.5% senior notes due 2012 and $1.1 million of accrued interest, pursuant to a privately negotiated transaction. The $32.0 million of 8.5% senior notes were retired upon receipt. On October 3, 2003, we issued an additional $23.7 million of our 7.75% senior notes due 2015 and accrued interest of $0.4 million in exchange for $16.8 million of our 8.125% senior notes due 2011, $6.0 million of our 8.375% senior notes due 2008 and accrued interest of $0.2 million, pursuant to a privately negotiated transaction. The $16.8 million of 8.125% senior notes and $6.0 million of 8.375% senior notes were retired upon receipt.

On August 12, 2002, we issued $250.0 million principal amount of 9% senior notes due 2012, which were exchanged on October 24, 2002 for substantially identical notes registered under the Securities Act of 1933. In a private offering on November 14, 2002 we issued an additional $50.0 million principal amount of 9% senior notes due 2012 which were exchanged on February 20, 2003 for substantially identical notes registered under the Securities Act of 1933.

On March 17, 1997, we issued $150.0 million principal amount of 8.5% senior notes due 2012. During the quarter ended March 31, 2001, Chesapeake purchased and subsequently retired $7.3 million of these notes for total consideration of $7.4 million, including accrued interest of $0.2 million and the write-off of $0.1 million of unamortized bond discount. On August 5, 2003, we exchanged $32.0 million principal of 8.5% senior notes for $33.5 million of our 7.75% senior notes discussed above. In the fourth quarter of 2003, we purchased and subsequently retired $106.4 million of these notes for a total consideration of $114.9 million, including accrued interest of $1.8 million. In connection with this repurchase transaction, we recorded a pre-tax loss of $20.8 million, consisting of $6.7 million of redemption premium, $1.8 million write-off of unamortized debt issue costs and notes discount, $0.3 million of transaction costs, and a write-off of the call option value of $12.0 million recorded as a discount on the 8.5% senior notes based on the hedging relationship between the notes and our 8.5% swaption further discussed in Note 10.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes have been fully and unconditionally guaranteed, on a joint and several basis, by each of our “restricted subsidiaries” (as defined in the respective indentures governing these notes) (collectively, the “guarantor subsidiaries”). Each guarantor subsidiary is a direct or indirect wholly-owned subsidiary.

The senior note indentures permit us to redeem the senior notes at any time at specified make-whole or redemption prices. The indentures contain covenants limiting us and the guarantor subsidiaries with respect to asset sales; the incurrence of additional indebtedness and the issuance of preferred stock; liens; sale and leaseback transactions; lines of business; dividend and other payment restrictions; mergers or consolidations; and transactions with affiliates.

Set forth below are condensed consolidating financial statements of the parent, guarantor subsidiaries and the non-guarantors. Chesapeake Energy Marketing, Inc., Mayfield Processing, L.L.C. and MidCon Compression, L.P. are wholly owned subsidiaries which are not guarantors of the senior notes. Chesapeake Energy Marketing, Inc. was a non-guarantor subsidiary for all periods presented. Mayfield Processing, L.L.C. and MidCon Compression, L.P. were established as non-guarantor subsidiaries during 2003. All of our other wholly-owned subsidiaries were guarantor subsidiaries during all periods presented.

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2003
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents, including restricted cash	$ 248	$ 32,131	$ 8,202	$ —	$ 40,581
Accounts receivable	181,538	127,717	11,000	(78,861)	241,394
Short-term derivative receivable	1,777	—	—	—	1,777
Short-term derivative instruments	—	—	2,690	—	2,690
Deferred income tax asset	—	—	36,705	—	36,705
Inventory and other	17,368	1,770	119	—	19,257
Total Current Assets	200,931	161,618	58,716	(78,861)	342,404
PROPERTY AND EQUIPMENT:					
Evaluated oil and gas properties	6,221,576	—	—	—	6,221,576
Unevaluated leasehold	227,331	—	—	—	227,331
Other property and equipment	82,230	58,083	85,578	—	225,891
Less: accumulated depreciation, depletion and amortization	(2,511,382)	(23,982)	(6,317)	—	(2,541,681)
Net Property and Equipment	4,019,755	34,101	79,261	—	4,133,117
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	—	—	853,184	(853,184)	—
Long-term derivative instruments	17,493	—	—	—	17,493
Long-term investments	5,000	—	26,544	—	31,544
Other assets	23,641	14	24,092	(14)	47,733
Total Other Assets	46,134	14	903,820	(853,198)	96,770
TOTAL ASSETS	$ 4,266,820	$195,733	$ 1,041,797	$ (932,059)	$ 4,572,291
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
CURRENT LIABILITIES:					
Accounts payable	$ 160,422	$ 120,369	$ —	$ (116,527)	$ 164,264
Accrued interest	—	—	46,648	—	46,648
Short-term derivative instruments	60,050	—	32,601	—	92,651
Other accrued liabilities	86,759	5,553	15,751	(43)	108,020
Revenues and royalties due others	63,907	—	—	37,666	101,573
Total Current Liabilities	371,138	125,922	95,000	(78,904)	513,156
OTHER LIABILITIES:					
Long-term debt, net	—	—	2,057,713	—	2,057,713
Revenues and royalties due others	13,921	—	—	—	13,921
Asset retirement obligation	48,812	—	—	—	48,812
Long-term derivative instruments	4,209	—	527	—	4,736
Deferred income tax liability (asset)	278,914	3,772	(91,660)	—	191,026
Other liabilities	10,117	—	—	—	10,117
Intercompany payables (receivables)	2,753,590	(1,026)	(2,752,593)	29	—
Total Other Liabilities	3,109,563	2,746	(786,013)	29	2,326,325
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	56	1	2,218	(57)	2,218
Preferred Stock	—	—	552,400	—	552,400
Other	786,063	67,064	1,178,192	(853,127)	1,178,192
Total Stockholders' Equity	786,119	67,065	1,732,810	(853,184)	1,732,810
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 4,266,820	$ 195,733	$ 1,041,797	$ (932,059)	$ 4,572,291

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2002
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents, including restricted cash	$ (31,893)	$ 24,448	$ 255,164	$ —	$ 247,719
Accounts receivable	122,074	69,362	3,006	(46,810)	147,632
Short-term derivative receivable	16,498	—	—	—	16,498
Deferred income tax asset	—	—	8,109	—	8,109
Inventory and other	14,202	1,157	—	—	15,359
Total Current Assets	120,881	94,967	266,279	(46,810)	435,317
PROPERTY AND EQUIPMENT:					
Evaluated oil and gas properties	4,334,833	—	—	—	4,334,833
Unevaluated leasehold	72,506	—	—	—	72,506
Other property and equipment	64,475	30,818	58,799	—	154,092
Less: accumulated depreciation, depletion and amortization	(2,146,538)	(20,789)	(4,220)	—	(2,171,547)
Net Property and Equipment	2,325,276	10,029	54,579	—	2,389,884
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	—	—	357,698	(357,698)	—
Deferred income tax asset (liability)	(124,455)	(1,941)	128,467	—	2,071
Long-term derivative instruments	2,666	—	—	—	2,666
Long-term investments	—	—	9,075	—	9,075
Other assets	20,246	57	16,349	(57)	36,595
Total Other Assets	(101,543)	(1,884)	511,589	(357,755)	50,407
TOTAL ASSETS	$ 2,344,614	$ 103,112	$ 832,447	$ (404,565)	$ 2,875,608
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable	$ 82,083	$ 71,316	$ —	$ (67,398)	$ 86,001
Accrued interest	—	—	35,025	—	35,025
Short-term derivative instruments	33,697	—	—	—	33,697
Other accrued liabilities	46,231	1,960	8,326	(52)	56,465
Revenues and royalties due others	33,776	—	—	20,588	54,364
Total Current Liabilities	195,787	73,276	43,351	(46,862)	265,552
OTHER LIABILITIES:					
Long-term debt, net	—	—	1,651,198	—	1,651,198
Revenues and royalties due others	13,797	—	—	—	13,797
Long-term derivative instruments	—	—	30,174	—	30,174
Other liabilities	5,687	1,325	—	—	7,012
Intercompany payables (receivable)	1,801,833	(1,677)	(1,800,151)	(5)	—
Total Other Liabilities	1,821,317	(352)	(118,779)	(5)	1,702,181
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	56	1	1,949	(57)	1,949
Preferred Stock	—	—	149,900	—	149,900
Other	327,454	30,187	756,026	(357,641)	756,026
Total Stockholders' Equity	327,510	30,188	907,875	(357,698)	907,875
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 2,344,614	$ 103,112	$ 832,447	$ (404,565)	$ 2,875,608

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
For the Year Ended December 31, 2003:					
REVENUES:					
Oil and gas sales	$ 1,296,822	$ —	$ —	$ —	$ 1,296,822
Oil and gas marketing sales	—	1,295,872	—	(875,262)	420,610
Total Revenues	1,296,822	1,295,872	—	(875,262)	1,717,432
OPERATING COSTS:					
Production expenses	137,583	—	—	—	137,583
Production taxes	77,893	—	—	—	77,893
General and administrative	18,802	3,453	1,498	—	23,753
Oil and gas marketing expenses	—	1,285,550	—	(875,262)	410,288
Oil and gas depreciation, depletion and amortization	369,465	—	—	—	369,465
Depreciation and amortization of other assets	8,715	3,193	4,885	—	16,793
Provision for legal settlements	6,402	—	—	—	6,402
Total Operating Costs	618,860	1,292,196	6,383	(875,262)	1,042,177
INCOME (LOSS) FROM OPERATIONS	677,962	3,676	(6,383)	—	675,255
OTHER INCOME (EXPENSE):					
Interest and other income	515	1,154	157,978	(156,820)	2,827
Interest expense	(148,102)	(11)	(163,063)	156,820	(154,356)
Loss on investment in Seven Seas	—	—	(2,015)	—	(2,015)
Loss on repurchases of Chesapeake debt	—	—	(20,759)	—	(20,759)
Equity in net earnings of subsidiaries	—	—	334,211	(334,211)	—
Total Other Income (Expense)	(147,587)	1,143	306,352	(334,211)	(174,303)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	530,375	4,819	299,969	(334,211)	500,952
Income tax expense (benefit)	201,541	1,831	(13,012)	—	190,360
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	328,834	2,988	312,981	(334,211)	310,592
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAXES	2,389	—	—	—	2,389
NET INCOME	$ 331,223	$ 2,988	$ 312,981	$ (334,211)	$ 312,981
For the Year Ended December 31, 2002:					
REVENUES:					
Oil and gas sales	$ 568,187	$ —	$ —	$ —	$ 568,187
Oil and gas marketing sales	—	548,388	—	(378,073)	170,315
Total Revenues	568,187	548,388	—	(378,073)	738,502
OPERATING COSTS:					
Production expenses	98,191	—	—	—	98,191
Production taxes	30,101	—	—	—	30,101
General and administrative	15,069	1,934	615	—	17,618
Oil and gas marketing expenses	—	543,809	—	(378,073)	165,736
Oil and gas depreciation, depletion and amortization	221,189	—	—	—	221,189
Depreciation and amortization of other assets	9,515	1,820	2,674	—	14,009
Total Operating Costs	374,065	547,563	3,289	(378,073)	546,844
INCOME (LOSS) FROM OPERATIONS	194,122	825	(3,289)	—	191,658
OTHER INCOME (EXPENSE):					
Interest and other income	1,580	597	120,046	(114,883)	7,340
Interest expense	(111,943)	(10)	(114,961)	114,883	(112,031)
Loss on investment in Seven Seas	—	—	(17,201)	—	(17,201)
Loss on repurchases of Chesapeake debt	—	—	(2,626)	—	(2,626)
Equity in net earnings of subsidiaries	—	—	51,104	(51,104)	—
Total Other Income (Expense)	(110,363)	587	36,362	(51,104)	(124,518)
INCOME BEFORE INCOME TAXES	83,759	1,412	33,073	(51,104)	67,140
Income tax expense (benefit)	33,502	565	(7,213)	—	26,854
NET INCOME	$ 50,257	$ 847	$ 40,286	$ (51,104)	$ 40,286

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
For the Year Ended December 31, 2001:					
REVENUES:					
Oil and gas sales	$ 820,318	$ —	$ —	$ —	$ 820,318
Oil and gas marketing sales	—	419,279	—	(270,546)	148,733
Total Revenues	820,318	419,279	—	(270,546)	969,051
OPERATING COSTS:					
Production expenses	75,374	—	—	—	75,374
Production taxes	33,010	—	—	—	33,010
General and administrative	12,201	1,311	937	—	14,449
Oil and gas marketing expenses	—	414,919	—	(270,546)	144,373
Oil and gas depreciation, depletion and amortization	172,902	—	—	—	172,902
Depreciation and amortization of other assets	6,035	80	2,548	—	8,663
Total Operating Costs	299,522	416,310	3,485	(270,546)	448,771
INCOME (LOSS) FROM OPERATIONS	520,796	2,969	(3,485)	—	520,280
OTHER INCOME (EXPENSE):					
Interest and other income	(130)	473	96,665	(94,131)	2,877
Interest expense	(100,531)	(2)	(91,919)	94,131	(98,321)
Loss on repurchases of Chesapeake debt	(13,618)	—	(63,049)	—	(76,667)
Impairments of investments in securities	(8,579)	—	(1,500)	—	(10,079)
Gain on sale of Canadian subsidiary	—	—	27,000	—	27,000
Gothic standby credit facility costs	—	—	(3,392)	—	(3,392)
Equity in net earnings of subsidiaries	—	—	239,968	(239,968)	—
Total Other Income (Expense)	(122,858)	471	203,773	(239,968)	(158,582)
INCOME BEFORE INCOME TAXES	397,938	3,440	200,288	(239,968)	361,698
Income tax expense (benefit)	160,034	1,376	(17,118)	—	144,292
NET INCOME	$ 237,904	$ 2,064	$ 217,406	$ (239,968)	$ 217,406

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
For the Year Ended December 31, 2003:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 981,939	$ (44,660)	$ 342,534	$ (334,211)	$ 945,602
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(838,908)	—	(1,127,442)	—	(1,966,350)
Additions to buildings and other fixed assets	(18,631)	(27,265)	(26,779)	—	(72,675)
Additions to long-term investments	(5,000)	—	(25,750)	—	(30,750)
Deposit for Concho acquisition	—	—	(10,000)	—	(10,000)
Deposit for South Texas Asset acquisition	(3,250)	—	—	—	(3,250)
Sale of non-oil and gas assets and recoveries of investments	314	—	5,485	—	5,799
Other investments	9	—	—	—	9
Cash (used in) provided by investing activities	(865,466)	(27,265)	(1,184,486)	—	(2,077,217)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowing	738,000	—	—	—	738,000
Payments on long-term borrowings	(738,000)	—	—	—	(738,000)
Cash received from issuance of senior notes, net of costs	—	—	485,445	—	485,445
Proceeds from issuance of preferred stock, net of costs	—	—	390,365	—	390,365
Proceeds from issuance of common stock, net of costs	—	—	177,427	—	177,427
Cash paid to repurchase senior notes, including redemption premium	—	—	(113,074)	—	(113,074)
Cash paid for common stock dividends	—	—	(27,253)	—	(27,253)
Cash paid for preferred stock dividends	—	—	(20,916)	—	(20,916)
Cash paid for financing cost of credit facility	(2,474)	—	—	—	(2,474)
Cash paid for treasury stock	—	—	(2,109)	—	(2,109)
Net increase in outstanding payments in excess of cash balances	28,315	—	—	—	28,315
Additions to deferred charges	—	—	(496)	—	(496)
Cash received from exercise of stock options	—	—	9,329	—	9,329
Intercompany advances, net	(110,091)	79,608	(303,728)	334,211	—
Cash provided by (used in) financing activities	(84,250)	79,608	594,990	334,211	924,559
NET INCREASE IN CASH AND CASH EQUIVALENTS	32,223	7,683	(246,962)	—	(207,056)
CASH, BEGINNING OF PERIOD	(31,975)	24,448	255,164	—	247,637
CASH, END OF PERIOD	$ 248	$ 32,131	$ 8,202	$ —	$ 40,581

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
For the Year Ended December 31, 2002:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 397,211	$ 1,360	$ 85,064	$ (51,104)	$ 432,531
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(419,100)	—	(311,892)	—	(730,992)
Additions to buildings and other fixes assets	(12,927)	(3,860)	(20,323)	—	(37,110)
Deposit for ONEOK acquisition	(15,000)	—	—	—	(15,000)
Sale of non-oil and gas assets	1,559	—	4,215	—	5,774
Additions to long-term investments	—	—	(2,408)	—	(2,408)
Other investments	(9)	—	—	—	(9)
Cash (used in) provided by investing activities	(445,477)	(3,860)	(330,408)	—	(779,745)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	252,500	—	—	—	252,500
Payments on long-term borrowings	(252,500)	—	—	—	(252,500)
Cash received from issuance of senior notes, net of costs	—	—	439,427	—	439,427
Proceeds from issuance of common stock, net of costs	—	—	164,104	—	164,104
Cash paid to repurchase senior notes, including redemption premium	—	—	(111,597)	—	(111,597)
Cash dividends paid on preferred stock and common stock	—	—	(15,164)	—	(15,164)
Additions to deferred charges	(2,902)	—	(421)	—	(3,323)
Cash received from exercise of stock options	—	—	3,810	—	3,810
Intercompany advances, net	30,506	7,234	(88,844)	51,104	—
Cash provided by (used in) financing activities	27,604	7,234	391,315	51,104	477,257
NET INCREASE IN CASH AND CASH EQUIVALENTS	(20,662)	4,734	145,971	—	130,043
CASH, BEGINNING OF PERIOD	(11,313)	19,714	109,193	—	117,594
CASH, END OF PERIOD	$ (31,975)	$ 24,448	$ 255,164	$ —	$ 247,637

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
For the Year Ended December 31, 2001:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 526,589	$ 22,484	$ 244,632	$ (239,968)	$ 553,737
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(736,280)	—	142,906	—	(593,374)
Additions to buildings and other fixes assets	(26,212)	(292)	(12,494)	—	(38,998)
Sale of non-oil and gas assets	3,204	—	—	—	3,204
Additions to long-term investments	—	—	(40,239)	—	(40,239)
Other investments	(825)	127	—	—	(698)
Cash (used in) provided by investing activities	(760,113)	(165)	90,173	—	(670,105)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	433,500	—	—	—	433,500
Payments on long-term borrowings	(458,500)	—	—	—	(458,500)
Cash received on issuance of senior notes, net of costs	—	—	1,028,275	—	1,028,275
Cash received from issuance of preferred stock, net of costs	—	—	145,086	—	145,086
Cash paid to purchase senior notes. including redemption premium	—	—	(906,021)	—	(906,021)
Cash dividends paid on preferred stock	—	—	(1,092)	—	(1,092)
Additions to deferred charges	(5,984)	—	(627)	—	(6,611)
Cash paid for purchase of preferred stock	—	—	(10)	—	(10)
Cash paid on make whole provision	—	—	(3,336)	—	(3,336)
Cash received from exercise of stock options	—	—	3,216	—	3,216
Intercompany advances, net	273,608	(9,805)	(503,771)	239,968	—
Cash provided by (used in) financing activities	242,624	(9,805)	(238,280)	239,968	234,507
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(545)	—	—	—	(545)
NET INCREASE IN CASH AND CASH EQUIVALENTS	8,555	12,514	96,525	—	117,594
CASH, BEGINNING OF PERIOD	(19,868)	7,200	12,668	—	—
CASH, END OF PERIOD	$ (11,313)	$ 19,714	$ 109,193	$ —	$ 117,594

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
For the Year Ended December 31, 2003:					
NET INCOME	$ 331,223	$ 2,988	$ 312,981	$ (334,211)	$ 312,981
Other comprehensive income (loss)—net of income tax:					
Change in fair value of derivative instruments	(24,917)	—	—	—	(24,917)
Reclassification of gain on settled contracts	2,363	—	—	—	2,363
Ineffective portion of derivatives qualifying for hedge accounting	5,703	—	—	—	5,703
Equity in net other comprehensive income (loss) of subsidiaries	—	—	(16,851)	16,851	—
Comprehensive income (loss)	$ 314,372	$ 2,988	$ 296,130	$ (317,360)	$ 296,130
For the Year Ended December 31, 2002:					
NET INCOME	$ 50,257	$ 847	$ 40,286	$ (51,104)	$ 40,286
Other comprehensive income (loss)—net of income tax:					
Change in fair value of derivative instruments	(27,041)	—	—	—	(27,041)
Reclassification of gain on settled contracts	(22,066)	—	—	—	(22,066)
Ineffective portion of derivatives qualifying for hedge accounting	2,135	—	—	—	2,135
Equity in net other comprehensive income (loss) of subsidiaries	—	—	(46,972)	46,972	—
Comprehensive income (loss)	$ 3,285	$ 847	$ (6,686)	$ (4,132)	$ (6,686)
For the Year Ended December 31, 2001:					
NET INCOME	$ 237,904	$ 2,064	$ 217,406	$ (239,968)	$ 217,406
Other comprehensive income (loss)—net of income tax:					
Change in fair value of derivative instruments	147,210	—	—	—	147,210
Reclassification of gain on settled contracts	(48,623)	—	—	—	(48,623)
Ineffective portion of derivatives qualifying for hedge accounting	(1,503)	—	—	—	(1,503)
Foreign currency translation adjustments	(3,551)	—	—	—	(3,551)
Transfer of translation adjustments related to sale of Canadian subsidiary	7,452	—	—	—	7,452
Cumulative effect of accounting change for financial derivatives	(53,573)	—	—	—	(53,573)
Equity in net other comprehensive income (loss) of subsidiaries	—	—	47,412	(47,412)	—
Comprehensive income	$ 285,316	$ 2,064	$ 264,818	$ (287,380)	$ 264,818

3. Notes Payable and Long-Term Debt

Notes payable and long-term debt consist of the following:

	December 31,	
	2003	2003
	($ in thousands)	
7.875% Senior Notes due 2004 (a)	$ 42,137	$ 42,137
8.5% Senior Notes due 2012	4,290	142,665
8.125% Senior Notes due 2011	728,255	800,000
8.375% Senior Notes due 2008	209,815	250,000
9.0% Senior Notes due 2012	300,000	300,000
7.5% Senior Notes due 2013	363,823	—
7.75% Senior Notes due 2015	236,691	150,000
6.875% Senior Notes due 2016	200,000	—
Discount on senior notes	(26,959)	(15,482)
Discount for interest rate swap and swaption (b)	(339)	(18,122)
Total notes payable and long-term debt	$2,057,713	$1,651,198

(a) This amount was classified as long-term debt based on our ability and intent to satisfy this obligation with funding from our bank credit facility.

(b) See Note 10 for further discussion related to these instruments.

We have a $350 million revolving bank credit facility (with a committed borrowing base of $350 million) which matures in May 2007. As of December 31, 2003, we had no outstanding borrowings under this facility and utilized $35.8 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 our senior unsecured long-term debt rating. The unused portion of the facility is subject to an annual commitment fee of 0.375%. Interest is payable quarterly. The collateral value and borrowing base are redetermined periodically.

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, purchase certain of our senior notes and create liens. 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, 2003, our current ratio was 1.6 to 1 and our fixed charge coverage ratio was 4.8 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 $25.0 million.

The aggregate scheduled maturities of notes payable and long-term debt for the five fiscal years ending December 31, 2008 and thereafter were as follows as of December 31, 2003 ($ in thousands):

2004	$ 42,137
2005	—
2006	—
2007	—
2008	209,815
After 2008	1,833,059
	$ 2,085,011

4. Contingencies and Commitments

Royalty Owner Litigation. 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 violates the terms of applicable leases and state law, that deductions from the proceeds of oil and gas production are 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.

In one such lawsuit that has been filed against Chesapeake and a subsidiary, the parties have entered into a settlement agreement, effective December 31, 2003, pursuant to which we have agreed to refund Oklahoma royalty owners $10.5 million, including interest. The refund amount includes $3.6 million relating to marketing fees which we have previously paid into the court ($0.3 million and $3.3 million were charged to provisions for legal settlements in 2003 and 2002, respectively), $2.4 million relating to gathering, compression, dehydration, field fuel or transportation costs with respect to certain of our gathering systems, and $4.5 million relating to other such gathering system costs and other claims. The lawsuit has been certified for settlement as a class action, and the court has preliminarily approved the settlement for the purpose of giving class members notice of the proposed settlement and setting a fairness hearing on May 6, 2004. Assuming the settlement is approved and is not appealed, the distribution of settlement proceeds is scheduled to occur prior to October 5, 2004. The class members are substantially all royalty owners under Oklahoma oil and gas leases or pooling orders covering wells in which any of Chesapeake, its subsidiaries or their predecessors is a joint working interest owner or operator. In connection with the settlement, we incurred a $7.2 million charge in the third and fourth quarter of 2003 for litigation and settlement costs in excess of our litigation reserves. We believe the potential liability associated with post-production claims made against us by royalty owners in three other pending lawsuits filed as class actions is not material. There has been no class certification in any of these cases.

Other Litigation. Chesapeake is currently involved in various other disputes incidental to its business operations. Management, after consultation with legal counsel, is of the opinion that the final resolution of all such currently pending or threatened litigation is not likely to have a material adverse effect on our consolidated financial position or results of operations.

Employment Agreements with Officers. Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and various other senior management personnel, which provide for annual base salaries, bonus compensation and various benefits. The agreements provide for the continuation of salary and benefits for varying terms in the event of termination of employment without cause. The agreements with the chief executive officer and chief operating officer have terms of five years commencing January 1, 2004. The term of each agreement is automatically extended for one additional year on each January 31 unless one of the parties provides 30 days notice of non-extension. The agreements with the chief financial officer and other senior managers expire on September 30, 2006. The company's employment agreements with the executive officers provide for payments in the event of a change in control. The chief executive officer and chief operating officer are each entitled to receive a payment in the amount of five times his base compensation and the prior year's benefits, plus a tax gross-up payment, and the chief financial officer and other officers are each entitled to receive a payment in the amount of two times his or her base compensation plus bonuses paid during the prior year.

Environmental Risk. Due to the nature of the oil and gas business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at December 31, 2003.

Other. We completed an acquisition of Permian Basin and Mid-Continent oil and gas assets from Concho Resources Inc. in January 2004. We paid approximately $420 million in cash for these assets, $10 million of which was paid in 2003.

We also completed an acquisition of South Texas gas assets in January 2004. We paid approximately $65 million for these assets, $3.3 million of which was paid in 2003.

Chesapeake has entered into various operating leases for office space and equipment. Future minimum lease payments required as of December 31, 2003 related to these operating leases are as follows ($ in thousands):

2004	$ 2,353
2005	1,547
2006	622
2007	316
2008	184
After 2008	415
Total	$ 5,437

Rent expense, including short-term rentals, for the years ended December 31, 2003, 2002 and 2001 was $13.1 million, $7.7 million and $6.4 million, respectively.

5. Income Taxes

The components of the income tax provision (benefit) for each of the periods presented below are as follows:

	Years Ended December 31,		
	2003	2000	2001
		($ in thousands)	
Current	$ 5,000	$ (1,822)	$ 3,565
Deferred:			
United States	186,824	28,676	136,991
Foreign	—	—	3,736
Total	$ 191,824[1]	$ 26,854	$ 144,292

(1) Includes $1.464,000 of tax expense related to the change in accounting principle.

The effective income tax expense (benefit) differed from the computed “expected” federal income tax expense (benefit) on earnings before income taxes for the following reasons:

	Years Ended December 31,		
	2003	2002	2001
		($ in thousands)	
Computed “expected” federal income tax provision	$ 176,682	$ 23,499	$ 126,594
State income taxes and other	10,968	3,492	15,061
Change in valuation allowance	4,364	—	2,441
Tax percentage depletion	(190)	(137)	(195)
Foreign taxes in excess of U.S. statutory rate	—	—	391
	$ 191,824	$ 26,854	$ 144,292

Deferred income taxes are provided to reflect temporary differences in the basis of net assets for income tax and financial reporting purposes. The tax-effected temporary differences and tax loss carryforwards which comprise deferred taxes are as follows:

	Years Ended December 31, 2003	2002
	($ in thousands)	
Deferred tax liabilities:		
Acquisition, exploration and development costs and related depreciation, depletion and amortization	$ (342,396)[1]	$ (265,837)
Deferred tax assets:		
Net operating loss carryforwards	$ 154,784 [1]	$ 256,547
Derivative liabilities and other	31,857 [1]	18,837
Percentage depletion carryforwards	3,228 [1]	3,063
Alternative minimum tax credits	5,011 [1]	11
Deferred tax assets	$ 194,880 [1]	$ 278,458
Net deferred tax asset (liability)	(147,516)	12,621
Less: Valuation allowance	(6,805)	(2,441)
Total deferred tax asset (liability)	$ (154,321)	$ 10,180
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 36,705	$ 8,109
Non-current deferred income tax asset	—	2,071
Non-current deferred income tax liability	(191,026)	—
	$ (154,321)	$ 10,180

(1) Activity includes a net asset of $4.9 million related to acquisitions, a benefit of $10.2 million related to derivative instruments, and a benefit of $7.2 million related to stock option compensation. These items were not recorded as part of the provision for income taxes.

SFAS 109 requires that we record a valuation allowance when it is more likely than not that some portion or all of deferred tax assets will not be realized. As of December 31, 2001, we determined that it is more likely than not that $2.4 million of the net deferred tax assets related to Louisiana net operating losses generated by Louisiana properties will not be realized and have recorded a valuation allowance equal to such amounts. During 2003, we determined that it was more likely than not that an additional $4.4 million of the deferred tax assets related to Louisiana net operating losses will not be realized and we recorded an additional valuation allowance equal to such amounts.

As of December 31, 2003, we classified $36.7 million of deferred tax assets as current that were attributable to the current portion of derivative liabilities and other current temporary differences. As of December 31, 2002, we classified $8.1 million of deferred tax assets as current that were attributable to the current portion of derivative liabilities and other current temporary differences.

At December 31, 2003, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $403.8 million. Additionally, we had $71.5 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $8.5 million of percentage depletion carryforwards. During 2003, we estimate that we will be able to utilize approximately $253.3 million of NOLs to reduce our 2003 federal taxable income. The NOL carryforwards expire from 2012 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. A summary of our NOLs follows:

	NOL	AMT NOL
	($ in thousands)	
Expiration Date:		
December 31, 2012	$ 171,586	$ —
December 31, 2018	42,187	—
December 31, 2019	139,222	57,414
December 31, 2020	5,156	1,393
December 31, 2021	12,701	5,313
December 31, 2022	32,988	7,399
Total	$ 403,840	$ 71,519

The ability of Chesapeake to utilize NOL carryforwards to reduce future federal taxable income and federal income tax of Chesapeake 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.

The following table summarizes our net operating losses as of December 31, 2003 and any related limitations:

	Total	Limited	Annual Limitation
		($ in thousands)	
Net operating loss	$ 403,840	$ 312,140	$ 46,658
AMT net operating loss	$ 71,519	$ 71,519	$ 21,081

Although no assurances can be made, we do not believe that an additional ownership change has occurred as of December 31, 2003. 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.

6. Related Party Transactions

As of December 31, 2003, we had accrued accounts receivable from our CEO and COO of $0.3 million and $2.6 million, respectively, representing billings from December 2003 which were paid in January 2004. Since Chesapeake was founded in 1989, our chief executive officer and chief operating officer have acquired small working interests in certain of our oil and gas properties by participating in our drilling activities. Joint interest billing accounts of the CEO and COO are settled in cash. Under their employment agreements, the CEO and COO are permitted to participate in all, or none, of the wells drilled by or on behalf of Chesapeake during each calendar quarter, but they are not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake's board of directors 30 days prior to the start of a quarter. Their participation is permitted only under the terms outlined in their employment agreements, which, among other things, limit their individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake's working interest would be reduced below 12.5% as a result of their participation.

In October 2001, we sold Chesapeake Canada Corporation, a wholly-owned subsidiary, for net proceeds of approximately $143.0 million. Our CEO and COO each received $2.0 million related to their fractional ownership interest in these Canadian assets, which they acquired and paid for pursuant to the terms of their employment agreements. The portion of the proceeds allocated to our CEO and COO was based upon the estimated fair values of the assets sold as determined by management and the independent members of our board of directors using a methodology similar to that used by Chesapeake for acquisitions of assets from disinterested third parties.

During 2003, 2002 and 2001, we paid legal fees of $2,123,000, $600,000, and $391,000, respectively, for legal services provided by a law firm of which a director is a member.

7. Employee Benefit Plans

We maintain three deferred compensation plans. They include the following:

- The Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan,
- The 401(k) Make-Up Plan and
- The Deferred Compensation Plan.

The Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan is a qualified 401(k) profit sharing plan. Eligible employees may elect to defer voluntary contributions to the plan. The amount an employee can contribute is subject to the plan contribution limitations and annual dollar limits as set out by the IRS. Chesapeake currently matches up to 15% of the employee's annual compensation dollar for dollar with Chesapeake's common stock purchased in the open-market. The Company contributed $4 million, $2.9 million and $2.0 million to this plan during 2003, 2002 and 2001, respectively.

In January 2003, Chesapeake established the 401(k) Make-Up Plan and the Deferred Compensation Plan, both of which are nonqualified deferred compensation plans as defined by the Internal Revenue Service. Eligible employees that complete a timely election to defer compensation to Chesapeake's 401(k) plan in excess of the Internal Revenue Service imposed maximum, may defer compensation up to a total of 60% of their salary and 100% of performance bonus in the aggregate for the 401(k) Plan, 401(k) Make-Up Plan and the Deferred Compensation Plan.

The 401(k) Make-Up Plan allows employees receiving a base salary and bonus compensation of at least $90,000 during the prior 12 month period, and having a minimum of five years of service, to defer additional compensation beyond the IRS imposed limit applicable to our Savings and Incentive Stock Bonus Plan. The Company provides a matching contribution equal to 100%, up to 15% of the participating employee's compensation. The employer match is payable in common stock. The 401(k) Make-Up Plan is an unsecured deferred compensation plan and participants are general creditors of the Company as to their deferred compensation in the plan. We contributed $1.2 million to this plan during 2003.

Under the Deferred Compensation Plan, eligible employees and non-employee directors that complete a timely election may defer receipt of a portion of their compensation to some future date. Chesapeake has no requirement to make a matching contribution to the Deferred Compensation Plan.

Any assets placed in trust by Chesapeake to fund future obligations of the 401(k) Make-Up Plan and the Deferred Compensation Plan are subject to the claims of creditors in the event of insolvency or bankruptcy.

8. Major Customers and Segment Information

Sales to individual customers constituting 10% or more of total revenues were as follows:

Year Ended December 31,	Customer	Amount ($ in thousands)	Percent of Total Revenues
2003	Reliant Energy Services	$189,140	11%
2003	Duke Energy Field Services	$163,329	10%
2002	Continental Natural Gas	$ 90,161	12%
2002	Duke Energy Field Services	$ 71,373	10%
2001	Continental Natural Gas	$102,286	11%

Chesapeake has two reportable segments under SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*, consisting of exploration and production and marketing. The reportable segment information can be derived from Note 2 as Chesapeake Energy Marketing, Inc., Mayfield Processing, L.L.C. and MidCon Compression, L.P., which are our marketing subsidiaries, are the only non-guarantor subsidiaries. Chesapeake Energy Marketing, Inc. was a non-guarantor subsidiary for all periods presented. Mayfield Processing, L.L.C. and MidCon Compression, L.P. were established as non-guarantor subsidiaries during 2003.

9. Stockholders' Equity and Stock-Based Compensation

In November 2003, we issued 1,725,000 shares of 5.00% cumulative convertible preferred stock, par value $.01 per share and liquidation preference $100 per share, in a public offering. As of December 31, 2003, 1,725,000 shares remain outstanding. The net proceeds from the offering were $167.6 million. Each preferred share is convertible at any time at the option of the holder into 6.0962 shares of common stock, subject to adjustment. At December 31, 2003, 10,515,945 shares of our common stock were reserved for issuance upon conversion. The conversion rate is based on an initial conversion price of $16.40 per common share, plus cash in lieu of fractional shares. The preferred stock is subject to mandatory conversion, at our option, (1) on or after November 18, 2006 at the same rate, if the market price of the common stock equals or exceeds 130% of the conversion price, or $21.32, for a specified time period and (2) on or after November 18, 2008, at the lower of conversion price and the then current market price of common stock if there are less than 250,000 shares of preferred stock outstanding at the time.

Annual cumulative cash dividends of $5.00 per share are payable quarterly on the fifteenth day of each February, May, August and November.

In March 2003, we issued 23,000,000 shares of Chesapeake common stock at $8.10 per share in a public offering for net proceeds of $177.4 million.

In March 2003, we issued 4,600,000 shares of 6.00% cumulative convertible preferred stock, par value $.01 per share and liquidation preference $50 per share, in a private offering, all of which are outstanding as of December 31, 2003. The net proceeds from the offering were $222.8 million. Each preferred share is convertible at any time at the option of the holder into 4.8605 shares of common stock, subject to adjustment. At December 31, 2003, 22,358,300 shares of common stock were reserved for issuance upon conversion. The conversion rate is based on an initial conversion price of $10.287 per common share, plus cash in lieu of fractional shares. The preferred stock is subject to mandatory conversion at our option, (1) on or after March 20, 2006 at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price, or $13.37, at the time and (2) on or after March 20, 2008 at the lower of the conversion price and the then current market price of the common stock if there are less than 250,000 shares of preferred stock outstanding at the time. Annual cumulative cash dividends of $3.00 per share are payable quarterly on the fifteenth day of March, June, September and December.

In December 2002, we issued 23,000,000 shares of Chesapeake common stock at $7.50 per share in a public offering for net proceeds of $164.1 million.

On November 13, 2001, we issued 3,000,000 shares of 6.75% cumulative convertible preferred stock, par value $.01 per share and liquidation preference $50 per share, in a private offering. As of December 31, 2003, 2,998,000 shares remain outstanding. The net proceeds from the offering were $145.1 million. Each preferred share is convertible at any time at the option of the holder into 6.4935 shares of our common stock, subject to adjustment. At December 31, 2003, 19,467,513 shares of our common stock were reserved for issuance upon conversion. The conversion rate is based on an initial conversion price of $7.70 per common share, plus cash in lieu of fractional shares. The preferred stock is subject to mandatory conversion, at our option, (1) on or after November 20, 2004 at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price, or $10.01, at the time and (2) on or after November 20, 2006 at the lower of the conversion price and the then current market price of the common stock if there are less than 250,000 shares of preferred stock outstanding at the time. Annual cumulative cash dividends of $3.375 per share are payable quarterly on the fifteenth day of each February, May, August and November.

On March 30, 2001, we issued 1,117,216 shares of Chesapeake common stock in exchange for 49.5% of RAM Energy, Inc.'s, outstanding common stock. Our shares were valued at $8.854 each, or $9.9 million in total. In the third quarter of 2001, we made make-whole cash payments of $3.3 million to the former RAM shareholders. In December 2001, we sold all the RAM shares we owned for minimal consideration.

In January 2001, we acquired Gothic Energy Corporation in a stock merger. We issued 3,989,813 common shares in exchange for Gothic common shares at the rate of 0.1908 of a share of Chesapeake common stock for each share of Gothic common stock. In addition, outstanding warrants and options to purchase Gothic common stock were converted to the right to purchase Chesapeake common stock based on the merger exchange ratio. As of December 31, 2003, 0.4 million shares of Chesapeake common stock may be purchased upon the exercise of such warrants and options at an average price of $14.55 per share.

In 2001, holders of our 7% cumulative convertible preferred stock converted 622,768 shares into 4,480,171 shares of common stock (at a conversion price of $6.95 per share), and we redeemed the remaining 1,269 shares of preferred stock for 7,239 shares of common stock and $3,000 of cash (at a redemption price of $52.45 per share, paid in 5.7 shares of common stock and cash of $2.45).

Stock-Based Compensation Plans

Under Chesapeake's 2003 Stock Incentive Plan, restricted stock and incentive and nonqualified stock options to purchase our common stock may be awarded to employees and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued and sold may not exceed 10 million shares. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option on the date of grant. Restricted stock and options granted become vested at dates determined by the compensation committee of the board of directors. No restricted stock or option can be granted under this plan after April 14, 2013. This plan has been approved by our shareholders. No options or restricted shares were issued during 2003 from this plan.

Under Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, 10,000 shares of Chesapeake's common stock will be awarded to each newly appointed non-employee director on his or her first day of service. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued may not exceed 50,000 shares. This plan was not required to be approved by our shareholders. In 2003, 10,000 shares of common stock were awarded to a new director from this plan.

Under Chesapeake's 2002 Non-Employee Director Stock Option Plan, non-qualified options to purchase our common stock may be granted to members of our board of directors who are not Chesapeake employees. Subject to any adjustments as provided by this plan, the aggregate number of shares which may be issued and sold may not exceed 500,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant, and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant. Options granted become exercisable at dates determined by the compensation committee of the board of directors. This plan also contains a formula award provision pursuant to which each non-employee director receives every quarter a ten-year immediately exercisable option to purchase 10,000 shares of common stock at an exercise price equal to the fair market value of the shares on the date of grant. No options can be granted under this plan after April 14, 2012. This plan has been approved by our shareholders.

Under Chesapeake's 2001 and 2002 Stock Option Plans, incentive and nonqualified stock options to purchase our common stock may be granted to employees and consultants of Chesapeake. Subject to any adjustment as provided by the plans, the aggregate number of shares which may be issued and sold may not exceed 3,200,000 and 3,000,000 shares, respectively. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant; provided, however, nonqualified stock options not exceeding 10% of the options issuable under each plan may be granted at an exercise price which is not less than 85% of the grant date fair market value. Options granted become exercisable at dates determined by the compensation committee of the board of directors. No options can be granted under the 2001 plan after February 28, 2011 and under the 2002 plan after February 29, 2012. These plans have been approved by our shareholders.

Under Chesapeake's 2000 and 2001 Executive Officer Stock Option Plans, nonqualified stock options to purchase our common stock may be granted to executive officers of Chesapeake. Subject to any adjustment as provided by the plan, the aggregate number of shares which may be sold may not exceed 2,500,000 shares under the 2000 plan and 4,000,000 shares under the 2001 plan and must represent issued shares which have been reacquired by Chesapeake. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant; provided, however, nonqualified stock options not exceeding 10% of the options issuable under this plan may be granted at an exercise price which is not less than 85% of the grant date fair market value. Options granted become exercisable at dates determined by the compensation committee of the board of directors. No options can be granted under the 2000 plan after April 25, 2010 or after April 14, 2011 under the 2001 plan. These plans were not required to be approved by our shareholders.

Under Chesapeake's 1999 Stock Option Plan, 2000 Employee Stock Option Plan, 2001 Nonqualified Stock Option Plan and 2002 Nonqualified Stock Option Plan, nonqualified stock options to purchase our common stock may be granted to employees and consultants of Chesapeake. Subject to any adjustment as provided by the respective plans, the aggregate number of shares which may be issued and sold may not exceed 3,000,000 shares from each of the 1999, 2000 and 2001 plans and 4,000,000 from the 2002 plan. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant; provided, however, nonqualified stock options not exceeding 10% of the options issuable under this plan may be granted at an exercise price which is not less than 85% of the grant date fair market value. Options granted become exercisable at dates determined by the compensation committee of the board of directors. No options can be granted after March 4, 2009 under the 1999 plan, after April 25, 2010 under the 2000 plan, after April 14, 2011 under the 2001 plan, and after February 29, 2012 under the 2002 plan. These plans were not required to be approved by our shareholders.

Under Chesapeake's 1994 Stock Option Plan and 1996 Stock Option Plan, incentive and nonqualified stock options to purchase our common stock may be granted to employees and consultants of Chesapeake. Subject to any adjustment as provided by the respective plans, the aggregate number of shares which may be issued and sold may not exceed 4,886,910 shares under the 1994 plan and 6,000,000 shares under the 1996 plan. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price of incentive stock options may not be less than the fair market value of the shares underlying the options on the date of grant. The exercise price of nonqualified stock options under the 1996 plan must be at least 85% of the fair market value of the shares underlying the options on the date of grant. Options granted become exercisable at dates determined by the compensation committee of the board of directors. No options can be granted under the 1994 plan after October 17, 2004 or under the 1996 plan after October 14, 2006. These plans were approved by our shareholders.

Chesapeake's 1992 Nonstatutory Stock Option Plan terminated on December 10, 2002. The last option grants under this plan were made in April 2002. The plan permitted grants of nonqualified stock options to purchase our common stock to directors of Chesapeake. Subject to any adjustment as provided by the plan, the aggregate number of shares which may be issued and sold may not exceed 3,132,000 shares. All options granted under the plan were made pursuant to a formula set forth in the plan. Under this provision, each director who was not an executive officer received every quarter a ten-year immediately exercisable option to purchase a specified number of shares of common stock at an option price equal to the fair market value of the shares on the date of grant. This plan was approved by our shareholders.

A summary of our stock option activity and related information follows:

	Years Ended December 31,					
	2003		2002		2001	
	Options	Weighted-Avg. Exercise Price	Options	Weighted-Avg. Exercise Price	Options	Weighted-Avg. Exercise Price
Outstanding Beginning of Period	24,576,775	$ 4.40	23,232,655	$ 3.96	18,399,162	$ 2.83
Granted	7,168,623	8.98	4,170,700	5.38	7,422,300	6.18
Exercised	(4,262,915)	3.04	(2,519,429)	1.83	(2,264,374)	1.83
Canceled/Forfeited	(249,198)	8.51	(307,151)	5.30	(324,433)	5.68
Outstanding End of Period	27,233,285	$ 5.78	24,576,775	$ 4.40	23,232,655	$ 3.96
Exercisable End of Period	12,131,098	$ 4.26	11,014,775	$ 3.55	7,495,255	$ 2.88
Shares Authorized for Future Grants	11,018,225		7,602,339		3,836,856	
Fair Value of Options Granted During the Period	$ 3.36		$ 2.31		$ 3.34	

The following table summarizes information about stock options outstanding at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Number Exercisable	Weighted-Avg. Exercise Price
$ 0.56 – $ 1.13	3,124,783	4.78	$ 1.07	3,124,783	$ 1.07
1.38 – 4.00	4,048,937	5.36	3.16	2,877,588	3.16
4.06 – 5.20	3,511,411	8.53	5.19	779,478	5.17
5.35 – 5.56	2,362,240	6.87	5.56	1,637,858	5.56
5.60 – 6.11	6,381,917	7.72	6.10	2,912,535	6.10
6.13 – 7.74	511,185	6.27	6.91	376,226	6.87
7.80 – 7.80	3,325,150	9.02	7.80	—	—
7.81 – 10.01	418,437	8.58	8.56	244,505	8.73
10.08 – 10.08	3,077,850	9.48	10.08	—	—
10.10 – 30.63	471,375	8.04	14.49	178,125	20.24
$ 0.56 – $ 30.63	27,233,285	7.41	$ 5.78	12,131,098	$ 4.26

The exercise of certain stock options results in state and federal income tax benefits to us related to the difference between the market price of the common stock at the date of disposition and the option price. During 2003, 2002 and 2001, we recognized tax benefits of $7.1 million, $2.4 million and $5.4 million, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Shareholder Rights Plan

Chesapeake maintains a shareholder rights plan designed to deter coercive or unfair takeover tactics, to prevent a person or group from gaining control of Chesapeake without offering fair value to all shareholders and to deter other abusive takeover tactics which are not in the best interest of shareholders.

Under the terms of the plan, each share of common stock is accompanied by one right, which given certain acquisition and business combination criteria, entitles the shareholder to purchase from Chesapeake one one-thousandth of a newly issued share of Series A preferred stock at a price of $25.00, subject to adjustment by Chesapeake.

The rights become exercisable 10 days after Chesapeake learns that an acquiring person (as defined in the plan) has acquired 15% or more of the outstanding common stock of Chesapeake or 10 business days after the commencement of a tender offer which would result in a person owning 15% or more of such shares. Chesapeake may redeem the rights for $0.01 per right within ten days following the time Chesapeake learns that a person has become an acquiring person. The rights will expire on July 27, 2008, unless redeemed earlier by Chesapeake.

10. Financial Instruments and 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, 2003, our oil and gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps and call options. 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 does 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.
- For call options, Chesapeake receives a cash premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, then Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

Chesapeake enters into counter-swaps from time to time for the purpose of locking in the value of a 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 lockin a specific gain (or loss) that will be unaffected by subsequent variability in oil and gas prices. Any lockedin gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and gas sales in the month of related production.

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.

In accordance with FASB Interpretation No. 39, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets, to the extent that a legal right of setoff exists.

Gains or losses from derivative transactions are reflected as adjustments to oil and gas sales on the consolidated statements 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 2003, 2002 and 2001 were $10.5 million, $(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 they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales. We recorded a gain (loss) on ineffectiveness of $(9.2) million, $(3.6) million and $2.5 million in 2003, 2002 and 2001, respectively.

The estimated fair values of our oil and gas derivative instruments as of December 31, 2003 and 2002 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31,	
	2003	2002
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price gas swaps	$(44,794)	$(21,523)
Fixed-price gas cap-swaps	(18,608)	(50,732)
Gas basis protection swaps	46,205	8,227
Fixed-price gas counter-swaps	—	37,048
Gas call options	(17,876)	—
Fixed-price gas locked swaps	1,777	16,498
Fixed-price crude oil swaps	—	(1,799)
Fixed-price crude oil cap-swaps	(11,692)	(2,252)
Estimated fair value	$(44,988)	$(14,533)

Based upon the market prices at December 31, 2003, we expect to transfer a loss of approximately $17.6 million from accumulated other comprehensive income to earnings during the next 12 months when the transactions actually close. All transactions hedged as of December 31, 2003 are expected to mature by December 31, 2007, with the exception of the basis protection swaps which extend through 2009.

Interest Rate Derivatives

We also utilize hedging strategies to manage the exposure our fixed-rate senior notes have to interest rate changes. By entering into interest rate swaps, we convert a portion of our fixed rate debt to floating rate debt. To the extent the interest rate swaps have been designated as fair value hedges, results are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement.

The following describes interest rate swap activity since 2002 ($ in thousands):

Date Initiated	Fair Value at December 31, 2003	Date Closed	Cash Settlement Received	Previously Recognized Income	2003 Interest Income	Interest Income to be Recognized
March 2002	$ —	July 2002	$ 7,500	$ 6,778	$ 599	$ 123
June 2002	—	July 2002	1,130	1,130	—	—
August 2003	870	January 2004	940	—	870	70
August 2003	1,292	January 2004	1,370	—	1,292	78

In April 2002, Chesapeake entered into a "swaption" with an unrelated counterparty with respect to its 8.5% senior notes due 2012. The notional amount of the swaption was $142.7 million, which was the principal amount then outstanding under the 8.5% senior notes. The 8.5% senior notes included a "call option" whereby Chesapeake may redeem the debt at declining redemption prices beginning in March 2004. Under the swaption, the counterparty received the option to elect whether or not to enter into an interest rate swap with Chesapeake in March 2004, and Chesapeake received $7.8 million. The interest rate swap, if executed by the counterparty, would require Chesapeake to pay a fixed rate of 8.5% while the counterparty pays Chesapeake a floating rate of 6 month LIBOR in arrears plus 0.75%. Additionally, if the counterparty elects to enter into the interest rate swap, it may also elect to force Chesapeake to settle the transaction at the then current value of the interest rate swap.

According to SFAS 133, a fair value hedge relationship exist between the embedded call option in the 8.5% senior notes and the swaption. The fair value of the swaption is recorded on the consolidated balance sheets as a liability, and the debt's carrying amount is adjusted by the change in the fair value of the call option subsequent to the initiation of the swaption. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense.

During the third quarter 2003, we exchanged and subsequently retired $32.0 million of our 8.5% senior notes. The exchange of debt was treated as a modification rather than an extinguishment. Accordingly, the adjustment to the carrying value of the debt of $3.3 million related to the application of hedge accounting was reflected as a discount on the notes issued in the exchange transaction and will be amortized to interest expense using the effective interest method. During the fourth quarter 2003, we purchased and subsequently retired $106.4 million of the remaining $110.7 million of 8.5% senior notes pursuant to a tender offer and recorded a $12.0 million loss related to the removal of the fair value designation of the corresponding amount of the swaption. Temporary fluctuations in the fair value of the portion of the swaption no longer designated as a fair value hedge are recorded as adjustments to interest expense. We recorded a $3.3 million unrealized loss in interest expense during 2003 due to a decline in the fair value of the portion of the swapion no longer designated as a fair value hedge.

As of December 31, 2003, the remaining notional amount of the swaption designated as a fair value hedge was $4.3 million. We have recorded an adjustment to the carrying amount of the debt of $0.5 million which represents the temporary fluctuations in the fair value of the call option included in the $4.3 million principal amount of 8.5% senior notes. Since the inception of the swaption, we have recorded a change in the fair market value of the swaption from a $7.8 million liability to a $32.6 million liability, an increase of $24.8 million. We have recorded as additional interest expense $5.6 million to reflect ineffectiveness after giving effect to the removal of the designation of a portion of the swaption as a fair value hedge under SFAS 133 as described previously.

On February 27, 2004, Chesapeake and the counterparty agreed to extend the swap exercise date to April 15, 2004. If the interest rate swap is exercised, on each succeeding March 15, the counterparty may elect to terminate the swap and cause it to be settled at the then current value of the interest rate swap. We may elect to terminate the swap and cause it to be settled at the then current value of the interest rate swap at any time during the term of the swap. Cash payments related to the interest rate swap, if initiated, or as a result of cash settlement at termination will be recorded as adjustments to interest expense.

Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards No. 107, *Disclosures About Fair Value of Financial Instruments*. We have determined the estimated fair value amounts by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term, fixed-rate debt using primarily quoted market prices. Our carrying amount for such debt, excluding discounts for interest rate swaps and the swaption, at December 31, 2003 and 2002 was $2,058.1 million and $1,669.3 million, respectively, compared to approximate fair values of $2,279.5 million and $1,744.7 million, respectively. The carrying amount for our 6.75% convertible preferred stock at December 31, 2003 was $149.9 million, with a fair value of $275.8 million. The carrying amount and fair value for our 6.00% convertible preferred stock at December 31, 2003 was $230.0 million. The carrying amount and fair value for our 5.00% preferred stock at December 31, 2003 was $172.5 million.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in cash and cash equivalents and derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in equity 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 and may at times exceed the federally insured limits.

11. Disclosures About Oil And Gas Producing Activities

Net Capitalized Costs

Evaluated and unevaluated capitalized costs related to Chesapeake's oil and gas producing activities are summarized as follows:

	2003 ($ in thousands)
Oil and gas properties:	
Proved	$ 6,221,576
Unproved	227,331
Total	6,48,907
Less accumulated depreciation, depletion and amortization	(2,480,261)
Net capitalized costs	$ 3,968,646

	2002 ($ in thousands)
Oil and gas properties:	
Proved	$ 4,334,833
Unproved	72,506
Total	4,407,339
Less accumulated depreciation, depletion and amortization	(2,123,773
Net capitalized costs	$ 2,283,566

Unproved properties not subject to amortization at December 31, 2003 and 2002 consisted mainly of the purchase of leasehold acquired through acquisitions and lease acquisition costs. We capitalized approximately $13.0 million, $5.0 million and $4.7 million of interest during 2003, 2002 and 2001, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. We will continue to evaluate our unevaluated properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

Costs Incurred in Oil and Gas Acquisition, Exploration and Development

Costs incurred in oil and gas property acquisition, exploration and development activities which have been capitalized are summarized as follows:

Year Ended December 31, 2003	U.S.	Canada	Combined
		($ in thousands)	
Development and leasehold costs	$ 543,371	$ —	$ 543,371
Exploration costs	103,424	—	103,424
Acquisition costs:			
Proved properties	1,110,077	—	1,110,077
Unproved properties	198,394	—	198,394
Deferred tax adjustments	(4,903)	—	(4,903)
Sales of oil and gas properties	(22,156)	—	(22,156)
Geological and geophysical costs	38,181	—	38,181
Asset retirement obligation (a)	39,686	—	39,686
Capitalized internal costs	35,494	—	35,494
Total	$ 2,041,568	$ —	$ 2,041,568

Year Ended December 31, 2002	U.S.	Canada	Combined
		($ in thousands)	
Development and leasehold costs	$ 266,291	$ —	$ 266,291
Exploration costs	89,422	—	89,422
Acquisition costs:			
Proved properties	316,583	—	316,583
Unproved properties	14,000	—	14,000
Deferred tax adjustments	62,398	—	62,398
Sales of oil and gas properties	(839)	—	(839)
Geological and geophysical costs	22,798	—	22,798
Capitalized internal costs	24,318	—	24,318
Total	$ 794,971	$ —	$ 794,971

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Year Ended December 31, 2001	U.S.	Canada(b)	Combined
		($ in thousands)	
Development and leasehold costs	$ 322,582	$ 11,090	$ 333,672
Exploration costs	47,937	8	47,945
Acquisition costs:			
Proved properties	669,201	—	669,201
Unproved properties	35,132	—	35,132
Deferred tax adjustments	36,309	—	36,309
Sales of oil and gas properties	(1,138)	(150,306)	(151,444)
Geological and geophysical costs	7,131	—	7,131
Capitalized internal costs	18,225	—	18,225
Total	$ 1,135,379	$ (139,208)	$ 996,171

(a) The amount includes $24.1 million of asset retirement costs recorded as a result of implementation of SFAS 143 effective January 1, 2003.

(b) In October 2001, we sold our Canadian subsidiary which had oil and gas operations primarily in Northeast British Columbia for net proceeds of approximately $143.0 million.

Results of Operations from Oil and Gas Producing Activities (unaudited)

Chesapeake's results of operations from oil and gas producing activities are presented below for 2003, 2002 and 2001. The following table includes revenues and expenses associated directly with our oil and gas producing activities. It does not include any interest costs and general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil and gas operations.

Year Ended December 31, 2003	**U.S.**	**Canada**	**Combined**
		($ in thousands)	
Oil and gas sales (b)	$ 1,296,822	$ —	$ 1,296,822
Production expenses	(137,583)	—	(137,583)
Production taxes	(77,893)	—	(77,893)
Depletion and depreciation	(369,465)	—	(369,465)
Imputed income tax provision (a)	(270,515)	—	(270,515)
Results of operations from oil and gas producing activities	$ 441,366	$ —	$ 441,366
Year Ended December 31, 2000			
Oil and gas sales (c)	$ 568,187	$ —	$ 568,187
Production expenses	(98,191)	—	(98,191)
Production taxes	(30,101)	—	(30,101)
Depletion and depreciation	(221,189)	—	(221,189)
Imputed income tax provision (a)	(87,482)	—	(87,482)
Results of operations from oil and gas producing activities	$ 131,224	$ —	$ 131,224
Year Ended December 31, 2001	**U.S.**	**Canada**	**Combined**
Oil and gas sales (d)	$ 788,390	$ 31,928	$ 820,318
Production expenses	(73,016)	(2,358)	(75,374)
Production taxes	(33,010)	—	(33,010)
Depletion and depreciation	(164,693)	(8,209)	(172,902)
Imputed income tax provision (a)	(207,068)	(9,612)	(216,680)
Results of operations from oil and gas producing activities	$ 310,603	$ 11,749	$ 322,352

(a) The imputed income tax provision is hypothetical (at the statutory rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision will be payable.
(b) Includes $10.5 million of unrealized gains on oil and gas derivatives.
(c) Includes $87.3 million of unrealized losses on oil and gas derivatives.
(d) Includes $84.8 million of unrealized gains on oil and gas derivatives.

Oil and Gas Reserve Quantities (unaudited)

The reserve information presented below is based upon reports prepared by independent petroleum engineers and Chesapeake's petroleum engineers.

- As of December 31, 2003, Ryder Scott Company L.P., Netherland, Sewell & Associates, Inc., Lee Keeling and Associates, and our internal reservoir engineers evaluated 31%, 26%, 17% and 26%, respectively, of the combined discounted future net revenues from our estimated proved reserves.
- As of December 31, 2002, Lee Keeling and Associates, Ryder Scott Company L.P., Netherland, Sewell & Associates, Inc., Williamson Petroleum Consultants, Inc. and our internal reservoir engineers evaluated 23%, 20%, 20%, 10% and 27%, respectively, of the combined discounted future net revenues from our estimated proved reserves.
- As of December 31, 2001, Ryder Scott Company L.P., Lee Keeling and Associates, Williamson Petroleum Consultants, Inc. and our internal reservoir engineers evaluated 26%, 24%, 22% and 28%, respectively, of the combined discounted future net revenues from our estimated proved reserves.

The information is presented in accordance with regulations prescribed by the Securities and Exchange Commission. Chesapeake emphasizes that reserve estimates are inherently imprecise. Our reserve estimates were generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available.

Proved oil and gas reserves represent 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 developed oil and gas reserves are those 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.

Presented below is a summary of changes in estimated reserves of Chesapeake for 2003, 2002 and 2001:

	U.S.			Canada			Combined		
	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
December 31, 2003									
Proved reserves, beginning of period	37,587	1,979,601	2,205,125	—	—	—	37,587	1,979,601	2,205,125
Extensions, discoveries and other additions	3,574	359,681	381,123	—	—	—	3,574	359,681	381,123
Revisions of previous estimates	1,329	48,388	56,365	—	—	—	1,329	48,388	56,365
Production	(4,665)	(240,366)	(268,356)	—	—	—	(4,665)	(240,366)	(268,356)
Sale of reserves-in-place	(183)	(9,626)	(10,723)	—	—	—	(183)	(9,626)	(10,723)
Purchase of reserves-in-place	13,780	722,362	805,041	—	—	—	13,780	722,362	805,041
Proved reserves, end of period	51,422	2,860,040	3,168,575	—	—	—	51,422	2,860,040	3,168,575
Proved developed reserves:									
Beginning of period	28,111	1,458,284	1,626,952	—	—	—	28,111	1,458,284	1,626,952
End of period	38,442	2,121,734	2,352,389	—	—	—	38,442	2,121,734	2,352,389
December 31, 2002									
Proved reserves, beginning of period	30,093	1,599,386	1,779,946	—	—	—	30,093	1,599,386	1,779,946
Extensions, discoveries and other additions	4,348	217,116	243,205	—	—	—	4,348	217,116	243,205
Revisions of previous estimates	3,189	70,359	89,493	—	—	—	3,189	70,359	89,493
Production	(3,466)	(160,682)	(181,478)	—	—	—	(3,466)	(160,682)	(181,478)
Sale of reserves-in-place	(24)	(1,003)	(1,146)	—	—	—	(24)	(1,003)	(1,146)
Purchase of reserves-in-place	3,447	254,425	275,105	—	—	—	3,447	254,425	275,105
Proved reserves, end of period	37,587	1,979,601	2,205,125	—	—	—	37,587	1,979,601	2,205,125
Proved developed reserves:									
Beginning of period	22,496	1,134,381	1,269,359	—	—	—	22,496	1,134,381	1,269,359
End of period	28,111	1,458,284	1,626,952	—	—	—	28,111	1,458,284	1,626,952
December 31, 2001									
Proved reserves, beginning of period	23,797	1,053,069	1,195,849	—	158,964	158,964	23,797	1,212,033	1,354,813
Extensions, discoveries and other additions	2,425	256,616	271,167	—	—	—	2,425	256,616	271,167
Revisions of previous estimates	(2,750)	(166,146)	(182,644)	—	—	—	(2,750)	(166,146)	(182,644)
Production	(2,880)	(135,096)	(152,376)	—	(9,075)	(9,075)	(2,880)	(144,171)	(161,451)
Sale of reserves-in-place	—	—	—	—	(149,889)	(149,889)	—	(149,889)	(149,889)
Purchase of reserves-in-place	9,501	590,943	647,950	—	—	—	9,501	590,943	647,950
Proved reserves, end of period	30,093	1,599,386	1,779,946	—	—	—	30,093	1,599,386	1,779,946
Proved developed reserves:									
Beginning of period	15,445	739,775	832,445	—	118,688	118,688	15,445	858,463	951,133
End of period	22,496	1,134,381	1,269,359	—	—	—	22,496	1,134,381	1,269,359

During 2003, Chesapeake acquired approximately 805 bcfe of proved reserves through purchases of oil and gas properties for consideration of $1,105 million (primarily in nine separate transactions of greater than $10 million each). We also sold 11 bcfe of proved reserves for consideration of approximately $22.2 million. During 2003, we recorded upward revisions of 56 bcfe to the December 31, 2002 estimates of our reserves. Approximately 11.1 bcfe of the upward revisions was caused by higher oil and gas prices at December 31, 2003. Higher prices extend the economic lives of the underlying oil and gas properties and thereby increase the estimated future reserves. The weighted average oil and gas wellhead prices used in computing our reserves were $30.22 per bbl and $5.68 per mcf at December 31, 2003, compared to $30.18 per bbl and $4.28 per mcf at December 31, 2002.

During 2002, Chesapeake acquired approximately 275 bcfe of proved reserves through purchases of oil and gas properties for consideration of $379 million (primarily in six separate transactions of greater than $10 million each). We also sold 1 bcfe of proved reserves for consideration of approximately $0.8 million. During 2002, we recorded upward revisions of 89 bcfe to the December 31, 2001 estimates of our reserves. Approximately 76 bcfe of the upward revisions was caused by higher oil and gas prices at December 31, 2002. Higher prices extend the economic lives of the underlying oil and gas properties and thereby increase the estimated future reserves. The weighted average oil and gas wellhead prices used in computing our reserves were $30.18 per bbl and $4.28 per mcf at December 31, 2002, compared to $18.82 per bbl and $2.51 per mcf at December 31, 2001.

During 2001, Chesapeake acquired 648 bcfe of proved reserves for consideration of $706 million in approximately 160 separate transactions (primarily in six separate transactions of greater than $10 million each). In October 2001, we sold our Canadian subsidiary, which had oil and gas operations primarily in northeast British Columbia, for approximately $143.0 million. Also during 2001, we recorded downward revisions to our U.S. oil and gas reserves of 183 bcfe. Approximately 156 bcfe of the downward revisions to our reserves was related to significantly lower gas and oil prices at December 31, 2001, which had the effect of reducing the economic life of our properties. The weighted average oil and gas wellhead prices used in computing our reserves were $18.82 per bbl and $2.51 per mcf at December 31, 2001, compared to $26.41 per bbl and $10.12 per mcf at December 31, 2000.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

Statement of Financial Accounting Standards No. 69 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Chesapeake has followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying year-end prices and costs to the estimated quantities of oil and gas to be produced. Actual future prices and costs may be materially higher or lower than the year-end prices and costs used. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions. Estimated future income taxes are computed using current statutory income tax rates including consideration for the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process.

The following summary sets forth our future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in SFAS 69 ($ in thousands):

December 31, 2003	
Future cash inflows(a)	$ 17,807,624
Future production costs	(3,816,607)
Future development costs	(912,594)
Future income tax provision	(3,859,081)
Net future cash flows	9,219,342
Less effect of a 10% discount factor	(3,909,763)
Standardized measure of discounted future net cash flows	$ 5,309,579
Discounted (at 10%) future net cash flows before income taxes	$ 7,333,142

December 31, 2002	
Future cash inflows(b)	$ 9,640,070
Future production costs	(2,273,610)
Future development costs	(606,042)
Future income tax provision	(1,867,315)
Net future cash flows	4,893,103
Less effect of a 10% discount factor	(2,059,185)
Standardized measure of discounted future net cash flows	$ 2,833,918
Discounted (at 10%) future net cash flows before income taxes	$ 3,717,645

December 31, 2001	
Future cash inflows(c)	$ 4,586,743
Future production costs	(1,169,199)
Future development costs	(450,181)
Future income tax provision	(484,474)
Net future cash flows	2,482,889
Less effect of a 10% discount factor	(1,021,916)
Standardized measure of discounted future net cash flows	$ 1,460,973
Discounted (at 10%) future net cash flows before income taxes	$ 1,646,667

(a) Calculated using weighted average prices of $30.22 per barrel of oil and $5.68 per mcf of gas.

(b) Calculated using weighted average prices of $30.18 per barrel of oil and $4.28 per mcf of gas.

(c) Calculated using weighted average prices of $18.82 per barrel of oil and $2.51 per mcf of gas.

In October 2001, we sold our Canadian subsidiary, which had oil and gas operations primarily in northeast British Columbia, for net proceeds of approximately $143.0 million.

The principal sources of change in the standardized measure of discounted future net cash flows are as follows:

December 31, 2003	U.S.	Canada	Combined
		($ in thousands)	
Standardized measure, beginning of period	$ 2,833,918	$ —	$ 2,833,918
Sales of oil and gas produced, net of production costs(a)	(1,070,815)	—	(1,070,815)
Net changes in prices and production costs	200,632	—	200,632
Extensions and discoveries, net of production and development costs	1,041,108	—	1,041,108
Changes in future development costs	74,719	—	72,719
Development costs incurred during the period that reduced future development costs	130,195	—	130,195
Revisions of previous quantity estimates	(106,053)	—	()
Purchase of reserves-in-place (b)	2,012,686	—	2,012,686
Sales of reserves-in-place (b)	(827)	—	(827)
Accretion of discount	371,765	—	371,765
Net change in income taxes	(1,139,836)	—	(1,139,836)
Changes in production rates and other	749,981	—	749,981
Standardized measure, end of period (c)	$ 5,309,579	$ —	$ 5,309,579

December 31, 2002

	U.S.	Canada	Combined
		($ in thousands)	
Standardized measure, beginning of period	$ 1,460,973	$ —	$ 1,460,973
Sales of oil and gas produced, net of production costs(a)	(527,162)	—	(527,162)
Net changes in prices and production costs	875,802	—	875,802
Extensions and discoveries, net of production and development costs	463,674	—	463,674
Changes in future development costs	32,812	—	32,812
Development costs incurred during the period that reduced future development costs	68,387	—	68,387
Revisions of previous quantity estimates	137,639	—	137,639
Purchase of reserves-in-place	528,734	—	528,734
Sales of reserves-in-place	(535)	—	(535)
Accretion of discount	164,667	—	164,667
Net change in income taxes	(698,033)	—	(698,033)
Changes in production rates and other	326,960	—	326,960
Standardized measure, end of period (c)	$ 2,833,918	$ —	$ 2,833,918

December 31, 2001

	U.S.	Canada	Combined
		($ in thousands)	
Standardized measure, beginning of period	$ 3,575,320	$ 487,941	$ 4,063,261
Sales of oil and gas produced, net of production costs(a)	(597,575)	(29,570)	(627,145)
Net changes in prices and production costs	(4,284,926)	—	(4,284,926)
Extensions and discoveries, net of production and development costs	292,051	—	292,051
Changes in future development costs	75,694	—	75,694
Development costs incurred during the period that reduced future development costs	32,955	—	32,955
Revisions of previous quantity estimates	(151,455)	—	(151,455)
Purchase of reserves-in-place	816,865	—	816,865
Sales of reserves-in-place	(157)	(458,371)	(458,528)
Accretion of discount	536,523	—	536,523
Net change in income taxes	1,604,216	—	1,604,216
Changes in production rates and other	(438,538)	—	(438,538)
Standardized measure, end of period (c)	$ 1,460,973	$ —	$ 1,460,973

(a) Excluding unrealized gains (losses) on derivatives.
(b) Purchases and sales of reserves are shown net of the 9.9 bcfe which was acquired and immediately sold for $19 million.
(c) The discounted amounts related to cash flow hedges that would affect future net cash flows have not been included in any of the periods presented.

12. Asset Retirement Obligations

Effective January 1, 2003, Chesapeake adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets.

We identified and estimated all of our asset retirement obligations for tangible, long-lived assets as of January 1, 2003. These obligations were for future plugging and abandonment costs for depleted oil and gas wells. Prior to the adoption of SFAS 143, we included an estimate of our asset retirement obligations related to our oil and gas properties in our calculation of oil and gas depreciation, depletion and amortization expense. Upon adoption of SFAS 143, we recorded the discounted fair value of our expected future obligations of $30.5 million, a cumulative effect of the change in accounting principle as an increase to earnings of $2.4 million (net of income taxes) and an increase in net oil and gas properties of $34.3 million. The pro-forma effect on prior periods' financial position and results of operations was not material.

The components of the change in our asset retirement obligations are shown below:

	Twelve Months Ended December 31, 2003
Asset retirement obligations, beginning balance	$30,479
Additions and revisions	19,445
Settlements and disposals	(4,255)
Accretion expense	3,143
Asset retirement obligations, ending balance	$48,812

13. Acquisitions and Divestitures

Acquisitions. In January 2003 we acquired the stock of a subsidiary of ONEOK, in May the stock of Oxley Petroleum and in October the partnership interests in Laredo Partners LP for an aggregate purchase price of approximately $638 million. The assets of these entities were comprised mainly of evaluated and unevaluated interest in oil and gas properties. These acquisitions were accounted for using the purchase method of accounting and, accordingly results of operations of these acquired entities have been included in our results of operations from the respective closing dates of these acquisitions. Had these acquisitions been consummated at January 1, 2003 the effect on revenues and operating costs for 2003 would not have been significant. In addition to the above noted business combinations, during 2003 we acquired interests in leaseholds and unevaluated and evaluated oil and gas properties for aggregate purchase consideration of approximately $654 million. The largest purchase of oil and gas assets was a purchase from a subsidiary of El Paso for $510 million in March 2003. Acquisitions of both companies and oil and gas assets during 2002 and 2001 amounted to $393 million and $741 million, respectively.

Divestiture of Chesapeake Canada Corporation. In October 2001, we sold Chesapeake Canada Corporation, a wholly-owned subsidiary, for net proceeds of approximately $143.0 million.

14. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2003 and 2002 are as follows ($ in thousands except per share data):

	Quarters Ended			
	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
Total revenues	$ 376,327(b)	$ 429,815	$ 454,549	$ 456,741
Gross profit(a)	150,952	169,902	182,741	171,660
Net income before cumulative effect of accounting change, net of tax	71,120	82,240	87,859	69,373
Cumulative effect of accounting change, net of tax	2,389	—	—	—
Net income	$ 73,509	$ 82,240	$ 87,859	$ 69,373(c)
Net earnings per share – basic:				
Income before cumulative effect of accounting change	$ 0.34	$ 0.36	$ 0.38	$ 0.29
Cumulative effect of accounting change	0.01	—	—	—
	$ 035	$ 0.36	$ 0.38	$ 0.29
Net earnings per share – assuming dilution:				
Income before cumulative effect of accounting change	$ 0.31	$ 0.31	$ 0.33	$ 0.25
Cumulative effect of accounting change	0.01	—	—	—
	$ 0.32	$ 0.31	$ 0.33	$ 0.25

	Quarters Ended			
	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
Total revenues	$ 89,989	$ 193,690	$ 196,466	$ 258,357
Gross profit(a)	(19,817)	62,067	57,723	91,685
Net income	(27,586)	25,033	16,600	26,239
Net earnings per common share:				
Basic	$ (0.18)	$ 0.14	$ 0.08	$ 0.14
Diluted	$ (0.18)	$ 0.13	$ 0.08	$ 0.13

(a) Total revenue less total operating costs.
(b) Gives effect to reclassification of unrealized gains (losses) on interest rate derivatives from risk management income (loss) to interest expense as discussed in Note 16 of the 2002 10-K/A.
(c) Includes a pre-tax loss on repurchases of debt of $20.8 million.

15. Recent Accounting Pronouncements

During 2002 and 2003, the Financial Accounting Standards Board issued the following Statements of Financial Accounting Standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In July 2002, the FASB issued SFAS No. 146, *Accounting For Costs Associated with Exit or Disposal Activities*. SFAS 146 is effective for exit or disposal activities initiated after December 31, 2002. We adopted this standard during the quarter ended March 31, 2003 and it did not have any impact on our financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation, or FIN 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantee of Indebtedness of Others*. FIN 45 requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. FIN 45's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The guarantor's previous accounting for guarantees that were issued before the date of FIN 45's initial application may not be revised or restated to reflect the effect of the recognition and measurement provisions of the Interpretation. The disclosure requirements are effective for financial statements of both interim and annual periods that end after December 15, 2002. Chesapeake is not a guarantor under any significant guarantees and thus this interpretation did not have a significant effect on the company's financial position or results of operations.

In March 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. SFAS 149 is effective for contracts entered into or modified after June 30, 2003. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. We adopted this standard during the quarter ended September 30, 2003 and it did not have any impact on our financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*. SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003 and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. This statement establishes new standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that an issuer classify a financial instrument that is within the scope of this statement as a liability because the financial instrument embodies an obligation of the issuer. This statement applies to certain forms of mandatorily redeemable financial instruments including certain types of preferred stock, written put options and forward contracts. Adoption of this standard did not have any significant impact on our financial position or results of operations.

In December 2003, the Securities and Exchange Commission issued Staff Accounting Bulletin 104, *Revenue Recognition*. SAB 104 revises or rescinds certain guidance included in previously issued staff accounting bulletins in order to make this interpretive guidance consistent with current authoritative accounting and auditing guidance and SEC rules and regulations relating to revenue recognition. This bulletin was effective immediately upon issuance. Chesapeake's current revenue recognition policies comply with SAB 104.

In January 2003, the FASB issued Financial Interpretation No. 46, *Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51* FIN 46 is an interpretation of Accounting Research Bulletin 51, "Consolidated Financial Statements," and addresses consolidation by business enterprises of variable interest entities (VIEs). The primary objective of FIN 46 is to provide guidance on the identification and financial reporting of entities over which control is achieved through means other than voting rights; such entities are known as VIEs, FIN 46 requires an enterprise to consolidate a VIE if that enterprise has a variable interest that will absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns, or both. An enterprise shall consider the rights and obligations conveyed by its variable interest in making this determination. At December 31, 2003, Chesapeake did not have any entities that would qualify for consolidation in accordance with the provisions of FIN 46, as amended. Therefore, the adoption of FIN 46, as amended, did not have an impact on our consolidated financial statements.

16. Subsequent Events

We completed an acquisition of Permian Basin and Mid-Continent oil and gas assets from Concho Resources Inc. in January 2004. We paid approximately $420 million in cash for these assets, $10 million of which was paid in 2003.

We also completed an acquisition of South Texas gas assets in January 2004. We paid $65 million for these assets, $3.3 million of which was paid in 2003.

On January 14, 2004, we issued 23,000,000 shares of common stock at a price to the public of $13.51 per share. We used the net proceeds from this offering of approximately $298.3 million to finance a portion of the acquisitions completed in January 2004.

On January 14, 2004, we completed a public exchange offer in which we retired $458.5 million of our 8.125% notes due 2011 and $10.8 million of accrued interest and issued $72.8 million of our 7.75% notes due 2015 and $2.8 million of accrued interest and $433.5 million of our 6.875% notes due 2016 and $4.1 million of accrued interest. The exchange of notes did not represent a substantial change in the terms of the debt instruments in accordance with EITF 96-19, accordingly, no gain or loss on debt extinguishment was recorded. We recognized transaction costs related to the exchange of approximately $6 million.

In January and February of 2004, we issued an additional $37.0 million of our 6.875% notes due 2016 and $0.5 million of accrued interest in exchange for $24.3 million of our 8.125% notes due 2011 and $0.7 million of accrued interest and $9.1 million of our 7.75% notes due 2015 and $0.1 million of accrued interest in four private exchange transactions.

Schedule II

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
($ in thousands)

Description	Balance at Beginning Of Period	Additions: Charged To Expense	Additions: Charged To Other Accounts	Deductions	Balance at End of Period
December 31, 2003:					
Allowance for doubtful accounts	$ 1,433	$ 156	$ 1,202	$ 122	$ 2,669
Valuation allowance for deferred tax assets	$ 2,441	$ 4,364(a)	$ —	$ —	$ 6,805
December 31, 2002:					
Allowance for doubtful accounts	$ 947	$ 315	$ 171	$ —	$ 1,433
Valuation allowance for deferred tax assets	$ 2,441	$ —	$ —	$ —	$ 2,441
December 31, 2001:					
Allowance for doubtful accounts	$ 1,085	$ 69	$ 44	$ 251	$ 947
Valuation allowance for deferred tax assets	$ —	$ 2,441(a)	$ —	$ —	$ 2,441

(a) As of December 31, 2001, we determined that it is more likely than not that $2.4 million of the net deferred tax assets related to Louisiana net operating losses generated by Louisiana properties will not be realized and have recorded a valuation allowance equal to such amounts. During 2003, we determined that it was more likely than not that an additional $4.4 million of the deferred tax assets related to Louisiana net operating losses will not be realized and we recorded an additional valuation allowance equal to such amounts.

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

Not applicable.

ITEM 9A. ***Controls and Procedures***

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the company's disclosure controls and procedures (as defined in Rule 13a-15 (e) under the Exchange Act). Based on this evaluation, they have concluded the company's disclosure controls and procedures are effective as of December 31, 2003. No changes in the company's internal control over financial reporting occurred during the quarter ended December 31, 2003 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

PART III

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

Directors

Aubrey K. McClendon, age 44, has served as Chairman of the Board, Chief Executive Officer and a director since co-founding the Company in 1989. From 1982 to 1989, Mr. McClendon was an independent producer of oil and gas in affiliation with Tom L. Ward, the Company's President and Chief Operating Officer. Mr. McClendon is a member of the Board of Visitors of the Fuqua School of Business at Duke University. Mr. McClendon graduated from Duke University in 1981.

Tom L. Ward, age 44, has served as President, Chief Operating Officer and a director of Chesapeake Energy Corporation since co-founding the Company in 1989. From 1982 to 1989, Mr. Ward was an independent producer of oil and gas in affiliation with Aubrey K. McClendon, the Company's Chairman and Chief Executive Officer. Mr. Ward is a member of the Board of Trustees of Anderson University in Anderson, Indiana. Mr. Ward graduated from the University of Oklahoma in 1981.

Frank Keating, age 59, has been a member of our board of directors since June 2003. Governor Keating has been the President and CEO of the American Council of Life Insurers, a large trade organization based in Washington, D.C. since January 2003. Governor Keating became a special agent in the Federal Bureau of Investigation in 1966 and then served as Assistant District Attorney in Tulsa County, Oklahoma. In 1972, Governor Keating was elected to the Oklahoma State House of Representatives and two years later was elected to the Oklahoma State Senate. In 1981 Governor Keating was appointed as the U.S. Attorney for the Northern District of Oklahoma and in 1985 Governor Keating began seven years of service in the Ronald Reagan and George W. Bush administrations serving as Assistant Secretary of the Treasury, Associate Attorney General in the Justice Department and as General Counsel and Acting Deputy Secretary of the Department of Housing and Urban Development. In 1994, Governor Keating was elected as Oklahoma's 25th Governor and served two consecutive four year terms. Governor Keating is a director of AMS, a software development company in Herndon, Virginia. Governor Keating graduated from Georgetown University in 1966 and from the University of Oklahoma College of Law in 1969.

Breene M. Kerr, age 75, has been a director of the Company since 1993. He is President of Brookside Company, Easton, Maryland. In 1969, Mr. Kerr founded Kerr Consolidated, Inc., which was sold in 1996. In 1969, Mr. Kerr co-founded the Resource Analysis and Management Group and remained its senior partner until 1982. From 1967 to 1969, he was Vice President of Kerr-McGee Chemical Corporation. From 1951 through 1967, Mr. Kerr worked for Kerr-McGee Corporation as a geologist and land manager. Mr. Kerr has served as chairman of the Investment Committee for the Massachusetts Institute of Technology and is a life member of the Corporation (Board of Trustees) of that university. He served as a director of Kerr-McGee Corporation from 1957 to 1981. Mr. Kerr currently is a trustee of the Brookings Institution in Washington, D.C. and the Woods Hole Oceanographic Institution in Woods Hole, Massachusetts, and has been an associate director since 1987 of Aven Gas & Oil, Inc., an oil and gas property management company located in Oklahoma City. Mr. Kerr graduated from the Massachusetts Institute of Technology in 1951.

Charles T. Maxwell, age 72, has been a member of the board of directors since September 2002. From 1999 to the present, Mr. Maxwell has been the Senior Energy Analyst at Weeden & Co., an institutional research and brokerage firm located in Greenwich, Connecticut. Entering the oil and natural gas industry in 1957, Mr. Maxwell worked for Mobil Oil Corporation for twelve years in the U.S., Europe, the Middle East and Africa. In 1968, Mr. Maxwell joined C.J. Lawrence, an institutional research and brokerage firm, as an oil analyst and was ranked by *Institutional Investor* magazine as No. 1 in his field in 1972, 1974, 1977, and 1981 through 1986. He rose to the position of Managing Director of C. J. Lawrence/Morgan Grenfell and retired from the firm in 1997, several years after it was acquired by Deutsche Bank. In addition, for the last 18 years he has been an active member of an Oxford (UK)-based organization comprised of OPEC officials and oil industry executives from 30 countries who meet twice a year to discuss trends in the energy industry. Mr. Maxwell graduated from Princeton University in 1953 and Oxford University in 1957.

Shannon T. Self, age 47, has been a director of the Company since 1993. He is a shareholder and co-founder of the law firm of Commercial Law Group, P.C., formerly Self, Giddens & Lees, Inc., a professional corporation, in Oklahoma City. Mr. Self was an associate and shareholder in the law firm of Hastie and Kirschner, Oklahoma City, from 1984 to 1991 and was employed by Arthur Young & Co. from 1979 to 1980. Mr. Self is a member of the Law Board of Northwestern University School of Law, a director of Piedra Capital, Ltd., a money management firm in Houston, Texas, and a director of Critical Technologies, Inc., a computer software company in Oklahoma City, Oklahoma. Mr. Self is a Certified Public Accountant. He graduated from the University of Oklahoma in 1979 and from Northwestern University Law School in 1984.

Frederick B. Whittemore, age 73, has been a director of the Company since 1993. Mr. Whittemore has been an advisory director of Morgan Stanley Dean Witter & Co. since 1989 and was a managing director or partner of the predecessor firms of Morgan Stanley Dean Witter & Co. from 1967 to 1989. He was Vice-Chairman of the American Stock Exchange from 1982 to 1984. Mr. Whittemore is a director of Partner Reinsurance Company, Bermuda; Maxcor Financial Group Inc., New York; SunLife of New York, New York; KOS Pharmaceuticals, Inc., Miami, Florida; and Southern Pacific Petroleum, Australia, NL. Mr. Whittemore graduated from Dartmouth College in 1953 and from the Amos Tuck School of Business Administration in 1954.

Executive Officers

In addition to Messrs. McClendon and Ward, the following are also executive officers of the Company.

Marcus C. Rowland, age 51, was appointed Executive Vice President in 1998 and has been the Company's Chief Financial Officer since 1993. He served as Senior Vice President from 1997 to 1998 and as Vice President – Finance from 1993 until 1997. From 1990 until his association with the Company, Mr. Rowland was Chief Operating Officer of Anglo-Suisse, L.P. assigned to the White Nights Russian Enterprise, a joint venture of Anglo-Suisse, L.P. and Phibro Energy Corporation, a major foreign operation which was granted the right to engage in oil and gas operations in Russia. Prior to his association with White Nights Russian Enterprise, Mr. Rowland owned and managed his own oil and gas company and prior to that was Chief Financial Officer of a private exploration company in Oklahoma City from 1981 to 1985. Mr. Rowland is a Certified Public Accountant. Mr. Rowland graduated from Wichita State University in 1975.

Martha A. Burger, age 51, has served as Treasurer since 1995 and as Senior Vice President – Human Resources since March 2000. She was the Company's Vice President – Human Resources from 1998 until March 2000, Human Resources Manager from 1996 to 1998 and Corporate Secretary from November 1999 until July 2000. From 1994 to 1995, she served in various accounting positions with the Company, including Assistant Controller – Operations. From 1989 to 1993, Ms. Burger was employed by Hadson Corporation as Assistant Treasurer and from 1993 to 1994 served as Vice President and Controller of Hadson Corporation. Prior to joining Hadson Corporation, Ms. Burger was employed by The Phoenix Resource Companies, Inc. as Assistant Treasurer and by Arthur Andersen & Co. Ms. Burger is a Certified Public Accountant and graduated from the University of Central Oklahoma in 1982 and from Oklahoma City University in 1992.

Michael A. Johnson, age 38, has served as Senior Vice President – Accounting, Controller and Chief Accounting Officer since March 2000. He served as Vice President of Accounting and Financial Reporting from March 1998 to 2000 and as Assistant Controller from 1993 to 1998. From 1991 to 1993, Mr. Johnson served as Project Manager for Phibro Energy Production, Inc., a Russian joint venture. From 1987 to 1991, he served as audit manager for Arthur Andersen & Co. Mr. Johnson is a Certified Public Accountant and graduated from the University of Texas at Austin in 1987.

Other Officers

Steven C. Dixon, age 45, has been Senior Vice President – Production since 1995 and served as Vice President – Exploration from 1991 to 1995. Mr. Dixon was a self-employed geological consultant in Wichita, Kansas from 1983 through 1990. He was employed by Beren Corporation in Wichita, Kansas from 1980 to 1983 as a geologist. Mr. Dixon graduated from the University of Kansas in 1980.

J. Mark Lester, age 51, has been Senior Vice President – Exploration since 1995 and served as Vice President – Exploration from 1989 to 1995. From 1986 to 1989, Mr. Lester was self-employed and acted as a consultant to Messrs. McClendon and Ward. He was employed by various independent oil companies in Oklahoma City from 1980 to 1986, and was employed by Union Oil Company of California from 1977 to 1980 as a geophysicist. Mr. Lester graduated from Purdue University in 1975 with a B.S. in Engineering Geology and in 1977 with an M.S. in Geophysics.

Henry J. Hood, age 43, was appointed Senior Vice President – Land and Legal in 1997 and served as Vice President – Land and Legal from 1995 to 1997. Mr. Hood was retained as a consultant to the Company during the two years prior to his joining the Company, and he was associated with the law firm of White, Coffey, Galt & Fite from 1992 to 1995. Mr. Hood was associated with or a partner of the law firm of Watson & McKenzie from 1987 to 1992. Mr. Hood is a member of the Oklahoma and Texas Bar Associations. Mr. Hood graduated from Duke University in 1982 and from the University of Oklahoma College of Law in 1985.

Thomas L. Winton, age 57, has served as Senior Vice President – Information Technology and Chief Information Officer since 1998. From 1985 until his association with the Company, Mr. Winton served as the Director, Information Services Department, at Union Pacific Resources Company. Prior to that period Mr. Winton held the positions of Regional Manager – Information Services from 1984 until 1985 and Manager – Technical Applications Planning and Development from 1980 until 1984 with UPRC. Mr. Winton also served as an analyst and supervisor in the Operations Research Division, Conoco Inc., from 1973 until 1980. Mr. Winton graduated from Oklahoma Christian University in 1969, Creighton University in 1973 and the University of Houston in 1980. Mr. Winton also completed the Tuck Executive Program, Amos Tuck School of Business, Dartmouth College in 1987.

Douglas J. Jacobson, age 50, has served as Senior Vice President – Acquisitions and Divestitures since August 1999. Prior to joining the Company, Mr. Jacobson was employed by Samson Investment Company from 1980 until August 1999, where he served as Senior Vice President – Project Development and Marketing from 1996 until August 1999. Prior to joining Samson, Mr. Jacobson was employed by Peat, Marwick, Mitchell & Co. Mr. Jacobson has served on various Oklahoma legislative commissions which have addressed issues in the oil and gas industry, including the Commission of Oil and Gas Production Practices and the Natural Gas Policy Commission. Mr. Jacobson is a Certified Public Accountant and graduated from John Brown University in 1976 and from the University of Arkansas in 1977.

Thomas S. Price, Jr., age 51, has served as Senior Vice President – Investor and Government Relations since April 2003. He was Senior Vice President - Corporate Development from March 2000 to April 2003, Vice President – Corporate Development from 1992 to March 2000 and a consultant to the Company during the prior three years. He was employed by Kerr-McGee Corporation, Oklahoma City, from 1988 to 1989 and by Flag-Redfern Oil Company from 1984 to 1988. Mr. Price is a member of the Independent Petroleum Association of America, the Mid-Continent Oil and Gas Association, the Oklahoma Independent Petroleum Association, the Texas Independent Producers and Royalty Owners Association, and the National Investor Relations Institute. Mr. Price graduated from the University of Central Oklahoma in 1983, from the University of Oklahoma in 1989 and from the American Graduate School of International Management in 1992.

James C. Johnson, age 46, has served as President of Chesapeake Energy Marketing, Inc., a wholly-owned subsidiary of Chesapeake Energy Corporation, since January 2000. He served as Vice President – Contract Administration for the Company from 1997 to 2000 and as Manager – Contract Administration from 1996 to 1997. From 1980 to 1996, Mr. Johnson held various gas marketing and land positions with Enogex, Inc., Delhi Gas Pipeline Corporation, TXO Production Corp. and Gulf Oil Corporation. Mr. Johnson is a member of the Natural Gas Association of Oklahoma and graduated from the University of Oklahoma in 1980.

Stephen W. Miller, age 47, was named Senior Vice President – Drilling in September 2001 after serving as Vice President – Drilling since 1996 and as District Manager – College Station District from 1994 to 1996. Mr. Miller held various engineering positions in the oil and gas industry from 1980 to 1993. Mr. Miller is a registered Professional Engineer in Texas, is a member of the Society of Petroleum Engineers and graduated from Texas A & M University in 1980.

Audit Committee Financial Expert

The Board has a standing audit committee consisting of Messrs. Kerr, Keating and Maxwell. All of the members of the audit committee are independent, as determined by the Board in accordance with Section 10A-3 of the Securities and Exchange Act of 1934 and Section 303 of the New York Stock Exchange's listing standards, and have accounting or related financial management experience required by such listing standards. In addition, Messrs. Kerr and Maxwell have been designated by the Board as "audit committee financial experts" as defined by Item 401(h) of Regulation S-K.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors and executive officers and persons who beneficially own more than 10% of the Company's common stock to file reports of ownership and subsequent changes with the Securities and Exchange Commission. Based only on a review of copies of such reports and written representations delivered to the Company by such persons, the Company believes that there were no violations of Section 16(a) by such persons during 2003.

Code of Business Conduct and Ethics

The Board has adopted a Code of Business Conduct and Ethics applicable to all directors, officers and employees of the Company, including our principal executive officer, principal financial officer, principal accounting officer or controller and persons performing similar functions. The Code of Business Conduct and Ethics is also posted on the Company's website at www.chkenergy.com.

If the Company makes any amendments to the Code of Business Conduct and Ethics, other than technical, administrative, or other non-substantive amendments, or grants any waivers, including implicit waivers, from a provision of the code to the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, we will disclose the nature of the amendment or waiver, its effective date and to whom it applies on our website.

ITEM 11. *Executive Compensation*

Summary Compensation Table

The following table sets forth for the years ended December 31, 2003, 2002 and 2001 the compensation earned in each period by (i) our chief executive officer and (ii) the four other most highly compensated executive officers.

		Annual Compensation			Securities Underlying Option Awards (# of Shares)(b)	All Other Compensation(c)
Name and Principal Position	**Year**	**Salary**	**Bonus**	**Other Annual Compensation(a)**		
Aubrey K. McClendon	2003	$ 737,500	$ 877,500	$ 209,579	1,375,000	$ 243,015
Chairman of the Board and	2002	$ 650,000	$ 686,000	$ 192,972	860,000	$ 52,687
Chief Executive Officer	2001	$ 537,500	$ 575,000	$ 199,158	1,600,000	$ 11,180
Tom L. Ward	2003	$ 737,500	$ 877,500	$ 209,637	1,375,000	$ 243,015
President and	2002	$ 650,000	$ 686,000	$ 180,310	860,000	$ 52,687
Chief Operating Officer	2001	$ 537,000	$ 575,000	$ 174,614	1,600,000	$ 11,180
Marcus C. Rowland	2003	$ 362,500	$ 387,000	(d)	160,000	$ 113,247
Executive Vice President -	2002	$ 320,000	$ 291,000	(d)	100,000	$ 23,931
Finance & Chief Financial Officer	2001	$ 282,500	$ 215,000	(d)	175,000	$ 14,270
Martha A. Burger	2003	$ 287,500	$ 236,500	(d)	85,000	$ 80,875
Treasurer and Senior Vice	2002	$ 245,000	$ 151,000	(d)	45,000	$ 17,681
President - Human Resources	2001	$ 200,000	$ 90,000	(d)	85,000	$ 14,756
Michael A. Johnson	2003	$ 217,500	$ 157,500	(d)	65,000	$ 56,549
Senior Vice President -	2002	$ 185,000	$ 111,000	(d)	35,000	$ 16,652
Accounting & Controller	2001	$ 170,000	$ 65,000	(d)	55,000	$ 11,130

(a) Includes the cost of personal benefits provided by the Company, including for 2003, 2002 and 2001, respectively, personal accounting support ($106,347, $89,740 and $73,926 for Mr. McClendon and $106,385, $89,774 and $75,413 for Mr. Ward) and travel allowances ($75,000, $75,000 and $100,000 for Mr. McClendon and $75,000, $62,284 and $75,413 for Mr. Ward).

(b) No awards of restricted stock or payments under long-term incentive plans were made by the Company to any of the named executives in any period covered by the table.

(c) Represents our matching contributions to the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan and the Chesapeake Energy Corporation 401(k) Make-Up Plan and premiums paid by the Company for term life insurance. In 2003, such amounts were $13,000, $228,875 and $1,140 for each of Messrs. McClendon and Ward; $16,000, $94,625 and $2,622 for Mr. Rowland; $17,250, $61,125 and $2,500 for Ms. Burger; and $15,000, $40,875 and $674 for Mr. Johnson, respectively.

(d) Perquisites and other personal benefits, securities or property did not exceed the lesser of $50,000 or 10% of the executive officer's salary and bonus during the year.

Stock Options Granted During 2003

The following table sets forth information concerning options to purchase our common stock granted during 2003 to the executive officers named in the Summary Compensation Table. Amounts represent stock options granted under the Company's 1994, 1996, 2000, 2001 and 2002 stock option plans and include incentive and nonqualified stock options. One-fourth of the number of shares represented by each option grant becomes exercisable on each of the first four grant date anniversaries. The exercise price of each option represents the market price of the common stock on the date of grant. The 1994, 1996, 2000, 2001 and 2002 plans provide for appropriate adjustments in the number of shares and option price in the event of a merger, consolidation, recapitalization, stock split, combination of shares, stock dividend or similar transaction involving the Company. Upon the Company's dissolution or a business combination of the Company with another corporation, if the options are not assumed by the acquirer, all outstanding options become automatically vested and are fully exercisable immediately prior to the transaction.

	Individual Grants				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation For Option Term(a)	
Name	Number of Securities Underlying Options Granted	Percent of Total Options Granted to Employees in 2003	Exercise Price Per Share	Expiration Date	5%	10%
Aubrey K. McClendon	750,000	10.80%	$ 7.80	01/08/13	$ 3,679,034	$ 9,323,393
	625,000	9.00%	$ 10.08	06/24/13	$ 3,962,036	$ 10,040,578
Tom L. Ward	750,000	10.80%	$ 7.80	01/08/13	$ 3,679,034	$ 9,323,393
	625,000	9.00%	$ 10.08	06/24/13	$ 3,962,036	$ 10,040,578
Marcus C. Rowland	85,000	1.22%	$ 7.80	01/08/13	$ 416,957	$ 1,056,651
	75,000	1.08%	$ 10.08	06/24/13	$ 475,444	$ 1,204,869
Martha A. Burger	45,000	0.64%	$ 7.80	01/08/13	$ 220,742	$ 559,404
	40,000	0.58%	$ 10.08	06/24/13	$ 253,570	$ 642,597
Michael A. Johnson	30,000	0.43%	$ 7.80	01/08/13	$ 147,161	$ 372,996
	35,000	0.50%	$ 10.08	06/24/13	$ 221,874	$ 562,272

(a) The assumed annual rates of stock price appreciation of 5% and 10% are set by the Securities and Exchange Commission and are not intended as a forecast of possible future appreciation in stock prices.

Aggregated Option Exercises in 2003 and December 31, 2003 Option Values

The following table sets forth information about options exercised by the named executive officers during 2003 and the unexercised options to purchase common stock held by them at December 31, 2003.

			Number of Securities Underlying Unexercised Options at 12/31/03		Value of Unexercised In-the-Money Options at 12/31/03(a)	
Name	Shares Acquired On Exercise	Value Realized(b)	Exercisable	Unexercisable	Exercisable	Unexercisable
Aubrey K. McClendon	994,607(c)	$ 8,530,419	1,977,500	3,313,750	$ 16,257,450	$ 22,634,163
Tom L. Ward	—	$ —	4,772,058	3,313,750	$ 50,095,500	$ 22,634,163
Marcus C. Rowland	197,500	$ 930,200	22,500	351,250	$ 168,075	$ 2,282,100
Martha A. Burger	4,100	$ 49,282	219,715	188,750	$ 2,239,514	$ 1,261,375
Michael A. Johnson	80,977	$ 538,922	2,500	135,000	$ 18,675	$ 873,788

(a) At December 31, 2003, the closing price of our common stock on the New York Stock Exchange was $13.58. "In-the-money options" are stock options with respect to which the market value of the underlying shares of common stock exceeded the exercise price at December 31, 2003. The values shown were determined by subtracting the aggregate exercise price of such options from the aggregate market value of the underlying shares of common stock on December 31, 2003.

(b) Represents amounts determined by subtracting the aggregate exercise price of such options from the aggregate market value of the underlying shares of common stock on the exercise date.

(c) Mr. McClendon continues to hold the shares acquired upon exercise as part of his common stock holders.

Employment Agreements

We have employment agreements with Messrs. McClendon and Ward, each of which provides, among other things, for an annual base salary of not less than $800,000, bonuses at the discretion of the Board of Directors, through its Compensation Committee, eligibility for stock options and benefits, including an automobile allowance, personal use of company-owned aircraft, club membership and personal accounting support. Each agreement has a term of five years commencing January 1, 2004, which term is automatically extended for one additional year on each January 31 unless one of the parties provides 30 days prior notice of non-extension. In addition, for each calendar year during which the employment agreements are in effect, Messrs. McClendon and Ward each agree to hold shares of the Company's common stock having an aggregate investment value equal to 500% of his annual base salary and bonus.

Under the employment agreements, Messrs. McClendon and Ward are permitted to participate in all of the wells spudded by or on behalf of the Company during each calendar quarter during the term of the agreement and continuing five years after termination of employment without cause or following a change in control. In order to participate, at least 30 days prior to the beginning of a calendar quarter the executive must notify the members of the Compensation Committee whether the executive elects to participate and, if so, the percentage working interest the executive will take in each well spudded by or on behalf of the Company during such quarter. The participation election by each of Messrs. McClendon and Ward may not exceed a 2.5% working interest in a well and is not effective for any well where the Company's working interest after elections by Messrs. McClendon and Ward to participate would be reduced to below 12.5%. Once an executive elects to participate, the percentage cannot be adjusted during the calendar quarter without the prior written consent of the Compensation Committee. No such adjustment has ever been requested or granted. For each well in which the executive participates, the Company bills to the executive an amount equal to the executive's participation percentage multiplied by the drilling and operating costs incurred in drilling the well, together with leasehold costs in an amount determined by the Company to approximate what third parties pay for similar leasehold in the area of the well. Payment is due for such costs promptly upon receipt of an invoice. The executive also receives a proportionate share of revenue from the well, less certain charges by the Company for marketing the production.

The agreements permit Messrs. McClendon and Ward to continue to conduct oil and gas activities individually or through their affiliates, but only to the extent such activities are conducted on oil and gas leases or interests they owned, or had the right to acquire as of July 1, 2001, or acquired from the Company pursuant to their employment or other agreements. Messrs. McClendon and Ward have participated in all wells drilled by the Company since its initial public offering in February 1993, except during the period from January 1, 1999 to March 31, 2000.

The Company has an employment agreement with Mr. Rowland that is in effect through September 30, 2006. It provides for an annual base salary of not less than $375,000. Mr. Rowland's employment agreement requires him to hold not less than 25,000 shares of the Company's common stock throughout the term of the agreement. Mr. Rowland's agreement provides for bonuses at the discretion of the Compensation Committee of the Board of Directors and eligibility for stock options and benefits, including an automobile allowance and club membership. Mr. Rowland's employment agreement permits him to continue to conduct oil and gas activities individually and through various related or family-owned entities, but prohibits him from acquiring, attempting to acquire or aiding another person in acquiring an interest in oil and gas exploration, development or production activities other than certain permitted activities without the Company's approval.

The Company also has employment agreements with Mr. Johnson and Ms. Burger in effect through September 30, 2006, with minimum annual base salaries of $230,000 for Mr. Johnson and $300,000 for Ms. Burger. Each agreement provides that the executive officer is eligible for bonuses, stock options and other benefits. The agreements require each executive to acquire and continue to hold at least 10,000 shares of the Company's common stock.

The Company may terminate any of the employment agreements with its executive officers at any time without cause; however, upon such termination Messrs. McClendon and Ward are entitled to continue to receive base compensation (defined as salary equal to the executive's base salary on the date of termination plus annual bonus compensation equal to the bonus compensation received by the executive during the twelve month period preceding the termination date) and benefits for the balance of the contract term. Messrs. Rowland and Johnson and Ms. Burger are entitled to continue to receive base salary (defined as salary equal to the executive's base salary the date of termination) and benefits for 180 days. Each of the employment agreements for Messrs. McClendon and Ward further provides that if, during the term of the agreement, there is a change of control and within three years thereafter (a) the agreement expires; (b) the agreement is not extended and the executive resigns within one year after the nonextension; (c) the executive is terminated other than for cause, death or incapacity; (d) the executive resigns as a result of (i) a change in his duties or title, (ii) a reduction in his compensation, (iii) a required relocation more than 25 miles from his then current place of employment, or (iv) a default by the Company under the agreement; (e) the agreement has not been assumed by any successor to or parent of the Company; or (f) the executive has agreed to remain employed by the Company for a period of three months to assist in the transition and thereafter resigns, then the executive officer will be entitled to a severance payment in an amount equal to five times his base compensation, plus five times the value of his benefits provided during the preceding twelve months, plus a grossup amount to be paid with respect to any excise or income taxes or penalties imposed on the severance payment. Change of control is defined in these agreements to include:

(1) a person acquiring beneficial ownership of 20% or more of the Company's outstanding common stock or the voting power of the Company's existing voting securities unless one of the circumstances described in clause 3(i), (ii) and (iii) below exists,
(2) a majority of the members of the Incumbent Board is replaced by directors who were not nominated or elected by the Incumbent Board (the current directors and directors later nominated or elected by a majority of such directors are referred to as the "Incumbent Board"),
(3) the consummation of a business combination such as a reorganization, merger, consolidation or sale of all or substantially all of the Company's assets unless following such business combination (i) the persons who beneficially owned the Company's

common stock and voting securities immediately prior to the business combination beneficially own more than 60% of such securities of the corporation resulting from the business combination in substantially the same proportions, (ii) no person beneficially owns 20% or more of such securities of the corporation resulting from the business combination unless such ownership existed prior to the business combination, or (iii) a majority of the members of the board of directors of the corporation resulting from the business combination were members of the Incumbent Board at the time of the execution or approval of the business combination agreement, and

(4) the approval by the shareholders of a complete liquidation or dissolution of the Company.

The employment agreements for Messrs. Rowland and Johnson and Ms. Burger further provide that if, during the term of the agreement, there is a change of control, then the executive officer will be entitled to a severance payment in an amount equal to 200 percent of the sum of the executive officer's base salary as of the date of the change of control plus annual bonus compensation paid to the executives including the twelve month period immediately prior to the change of control. The right to such compensation is subject to the executive officer's continued compliance with the terms of the employment agreement. Change of control is defined in these agreements as defined in Messrs. McClendon and Ward agreements.

Directors' Compensation

Currently, non-employee director compensation consists of (1) an annual retainer of $15,000, payable in quarterly installments of $3,750, (2) $6,250 and $1,250 payable for each Board meeting attended in person and telephonically, respectively, not to exceed $45,000 per year for Board meetings attended, and (3) a quarterly grant of stock options to purchase 11,250 shares of our common stock. Nonqualified stock options are granted under the Company's 2002 Non-Employee Director Stock Option Plan on the first business day of each calendar quarter, have a term of ten years, are granted at an exercise price equal to the market price on the date of grant and are fully exercisable upon grant. Commencing July 1, 2004, the non-employee directors' quarterly option grants will be increased to 12,500 options under this plan. Non-employee directors will receive $7,500 and $1,500 payable for each live and telephonic meeting attended, respectively. Such fees for live and telephonic meetings will be subject to an annual meeting fee maximum of $50,000. Officers who also serve as directors do not receive fees for serving as directors.

During 2003, each non-employee director received cash compensation of $43,750, comprised of an annual retainer of $15,000, and $28,750 for meetings of the Board attended. In addition, during 2003, non-employee directors received nonqualified stock options to purchase a total of 42,500 shares of our common stock at exercise prices equal to the market price on the dates of grant. Directors were also reimbursed for travel and other expenses.

Directors are also eligible to defer all, or a portion, of their annual retainers and/or meeting fees into the Chesapeake Energy Corporation Deferred Compensation Plan on a tax favored basis for at least two years.

Under the Company's 2003 Stock Award Plan for Non-Employee Directors, 10,000 shares of the Company's common stock will be awarded to each newly appointed non-employee director on his or her first day of service. In 2003, Mr. Keating was awarded 10,000 shares of common stock subsequent to his appointment as a director.

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

The table below sets forth (i) the name and address and beneficial ownership of each person known by management to own beneficially more than 5% of our outstanding common stock, and (ii) the beneficial ownership of common stock of our nominees, directors and executive officers listed in the foregoing Summary Compensation Table and by all directors and executive officers of the Company as a group. Unless otherwise noted, information is given as of March 10, 2004 and the persons named below have sole voting and/or investment power with respect to such shares.

	Common Stock			
Beneficial Owner	**Outstanding Shares**	**Share Equivalents**	**Total Ownership**	**Percent of Class**
Tom L. Ward(1)(2) .... 6100 North Western Avenue Oklahoma City, OK 73118	10,040,910 (a)	6,961,243 (b)	17,164,653	6.64%
Aubrey K. McClendon(1)(2) .... 6100 North Western Avenue Oklahoma City, OK 73118	11,330,508 (c)	4,166,685 (d)	15,659,693	6.12%
FMR Corp. .... 82 Devonshire Street Boston, MA 02109	8,941,180	3,318,383(e)	12,259,563	4.87

Frederick B. Whittemore(1)	716,700 (f)	977,500 (g)	1,694,200	(3)
Shannon T. Self(1)	124,742 (h)	357,500 (i)	482,242	(3)
Breene M. Kerr(1)	253,524 (j)	31,250 (i)	284,774	(3)
Charles T. Maxwell(1)	15,000 (k)	58,750 (i)	73,750	(3)
Frank A. Keating	10,000	33,750 (i)	43,750	(3)
Martha A. Burger(2)	34,225 (l)	248,465 (i)	282,690	(3)
Marcus C. Rowland(2)	58,460 (l)	10,000	68,460	(3)
Michael A. Johnson(2)	32,301 (l)	20,000 (i)	52,301	(3)
All directors and executive officers as a group	22,616,370	12,440,143	35,056,513	13.47%

(1) Director

(2) Executive officer

(3) Less than 1%

(a) Includes (i) 1,563,510 shares held by TLW Investments, Inc., an Oklahoma corporation of which Mr. Ward is sole shareholder and chief executive (ii) 21,435 shares held by Mr. Ward's immediate family sharing the same household, (iii) 43,452 shares purchased on behalf of the executive officer in the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan and (iv) 22,812 phantom shares allocated to each executive officer in the Chesapeake Energy Corporation 401(k) Make-Up Plan. Excluded are the shares of our common stock beneficially owned by Mr. McClendon which may be attributed to Mr. Ward based on a jointly filed Schedule 13D. Mr. Ward disclaims such ownership.

(b) Includes (i) 5,112,603 shares of common stock which can be acquired on March 10, 2004 or 60 days thereafter through the exercise of stock options, (ii) 1,543,830 shares of common stock issuable upon conversion of 6.75% preferred stock and (iii) 304, 810 shares of common stock issuable upon conversion of 5.0% preferred stock.

(c) Includes (i) 13,560 shares held by Chesapeake Investments, an Oklahoma limited partnership of which Mr. McClendon is sole general partner, (ii) 91,109 shares purchased on behalf of the executive officer in the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan and (iii) 22,812 phantom shares allocated to each executive officer in the Chesapeake Energy Corporation 401(k) Make-Up Plan. Excluded are the shares beneficially owned by Mr. Ward which may be attributed to Mr. McClendon based on a jointly filed Schedule 13D. Mr. McClendon disclaims such ownership.

(d) Includes (i) 2,318,045 shares of common stock which can be acquired on March 10, 2004 or 60 days thereafter through the exercise of stock options, (ii) 1,543,830 shares of common stock issuable upon conversion of 6.75% preferred stock and (iii) 304,810 shares of common stock issuable upon conversion of 5.0% preferred stock.

(e) Consists of 586,300 shares of the Company's 6.75% and 6.0% convertible preferred stock which is convertible into 3,318,383 shares of the Company's common stock based upon a Schedule 13G filed on February 17, 2004. The Schedule 13G reports sole power to vote 863,075 shares and sole power to dispose or to direct the disposition of all shares.

(f) Includes 41,750 shares held by Mr. Whittemore as trustee of the Whittemore Foundation.

(g) Includes 227,500 shares of common stock which can be acquired through the exercise of stock options and 750,000 options to purchase shares of our common stock owned by Messrs. Ward and McClendon issued to Mr. Whittemore (394,688 shares from Mr. McClendon and 355,312 shares from Mr. Ward).

(h) Includes 97,242 shares held by Pearson Street Limited Partnership, an Oklahoma limited partnership of which Mr. Self is general partner and the remaining partner is Mr. Self's spouse.

(i) Represents shares of common stock which can be acquired through the exercise of stock options on March 10, 2004 or 60 days thereafter.

(j) Includes 138,500 shares held by Talbot Fairfield II Limited Partnership, of which Mr. Kerr is a general partner.

(k) Includes 15,000 shares held by Maxwell Family Living Trust.

(l) Includes shares purchased on behalf of the executive officer in the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan and phantom shares allocated to each executive officer in the Chesapeake Energy Corporation 401(k)

Make-Up Plan (Martha A. Burger, 24,165 shares; Marcus C. Rowland, 30,952 shares; and Michael A. Johnson, 21,471 shares).

Equity Compensation Plan Information

The following table provides information as of December 31, 2003 about shares of the Company's common stock issuable under the equity compensation plans we maintain for our employees, consultants and/or directors:

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by shareholders	10,715,037	$5.79	10,223,527(1)
Equity compensation plans not approved by shareholders	16,485,455	$5.77	834,698
Total (2)	27,200,492	$5.78	11,058,225

(1) Does not include common stock issuable under our 401(k) Make-Up Plan.

(2) Does not include 32,793 shares of common stock issuable upon the exercise of stock options assumed by the Company in connection with its acquisition of Hugoton Energy Corporation. The weighted average exercise price of these assumed options is $7.63.

We have not obtained shareholder approval of stock option plans which cover only treasury shares or are broadly-based plans under the rules of the NYSE. Our treasury share plans are the 2000 and 2001 Executive Officer Stock Option Plans. Only executive officers are eligible to receive nonqualified stock options under these plans. Under our broadly-based plans, nonqualified stock options may be granted to employees and consultants. These plans are the 1999 Stock Option Plan, the 2000 Employee Stock Option Plan, and the 2001 and 2002 Nonqualified Stock Option Plans. The maximum period for exercise of an option granted under any of these plans may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant; provided, however, nonqualified stock options not exceeding 10% of the options issuable under a plan may be granted at an exercise price which is not less than 85% of the grant date fair market value. Options granted become exercisable at dates determined by the Compensation Committee of the Board of Directors. The plans provide for appropriate adjustments in the number of shares and option price in the event of a merger, consolidation, recapitalization, stock split, combination of shares, stock dividend or similar transaction involving the Company. Upon the Company's dissolution or a business combination of the Company with another corporation, if the options are not assumed by the acquirer, all outstanding options become automatically vested and are fully exercisable immediately prior to the transaction.

In 2003, the Board of Directors adopted our 2003 Stock Award Plan for Non-Employee Directors and 401(k) Make-Up Plan without shareholder approval. The 2003 Stock Award Plan for Non-Employee Directors provides that 10,000 shares of our common stock will be awarded to each newly appointed director on his or her first day of service. Up to a total of 50,000 shares may be issued under this plan. The 401(k) Make-Up Plan allows employees receiving combines base salary and bonus compensation of $90,000 and having at least five years of service to defer additional compensation beyond the IRS imposed limit applicable to our Savings and Incentive Stock Bonus Plan and receive a company match payable in common stock on up to 15% of each employee's aggregate compensation deferred in the Savings and Incentive Stock Bonus Plan and the 401(k) Make-Up Plan. The 401(k) Make-Up Plan is an unfunded deferred compensation plan and participants are general creditors of the Company as to their deferred compensation in the plan.

ITEM 13. *Certain Relationships and Related Transactions*

Legal Counsel. Shannon T. Self, a director of the Company, is a shareholder in the law firm Commercial Law Group, P.C., ("CLG") formerly Self, Giddens & Lees, Inc. CLG acts as special counsel to the Company on an ongoing basis with respect to general corporate matters, corporate structure, mergers and acquisitions, bank credit facilities, indenture maintenance and other special projects. CLG has advised the Company that it provides these legal services to the Company on the same terms as it provides services to clients not related to the Company. For services rendered by CLG, the Company pays all amounts for fees and expenses to CLG and not to Mr. Self. The Company uses multiple law firms and believes that the legal services provided by CLG and the rates charged for such services are competitive with the services and rates provided to the Company by other law firms. During 2003, we paid $2,123,000 for such legal services.

Oil and Gas Operations. The table below presents information about drilling, completion, equipping and operating costs billed to Messrs. McClendon and Ward from January 1, 2003 to December 31, 2003, the largest amount owed by them during the period and the balances owed by them at December 31, 2002 and 2003 with respect to working interests they own in Company wells. Such costs are accumulated at the end of each month, but are not billed to working interest owners until the following month. During 2003, Messrs. McClendon and Ward paid each invoice promptly upon receipt. See "Employment Agreements" for a description of terms covering the participation by Messrs. McClendon and Ward in our wells.

	Aubrey K. McClendon	**Tom L. Ward**
	(in thousands)	
Balance billed and unpaid at December 31, 2002	$ 0	$ 0
Amount billed in 2003	$ 22,440	$ 22,443
Largest outstanding balance (month end)	$ 0	$ 0
Balance billed and unpaid at December 31, 2003	$ 0	$ 0

Other Relationships. Mr. Ward's brother, Ronnie Ward, has served as the Company's Northern Mid-Continent Land Manager since 1994. Ronnie Ward was paid an aggregate salary and bonus of $_____ in 2003.

ITEM 14. *Principal Accounting Fees and Services*

Aggregate fees for professional services rendered for the Company by PricewaterhouseCoopers LLP in 2003 and 2002 were:

	2003	**2002**
Audit	$ 814,000	$ 530,000
Audit-Related	25,000	16,000
Tax	103,000	182,000
All Other	1,000	-
Total	$ 943,000	$ 728,000

Audit Fees

Fees for the 2003 audit and quarterly reviews, as well as the preparation of comfort letters, consents and assistance with and review of documents filed with the SEC in 2003, were $814,000, of which $346,000 related to the annual audit, $50,000 related to interim reviews, $9,000 related to consultations on financial accounting and reporting matters in connection with the annual audit, and $409,000 related to services provided in connection with our issuance of senior notes, preferred stock and common stock. Fees for the 2002 audit and quarterly reviews, as well as the preparation of comfort letters, consents and assistance with and review of documents filed with the SEC, were $530,000, of which $305,000 related to the annual audit, $41,000 related to interim reviews, and $184,000 related to services provided in connection with our issuance of senior notes, preferred stock and common stock.

Audit-Related Fees

Fees for the audit of employee benefit plans in 2003 and 2002 were $18,000 and $16,000, respectively. Additionally, audit-related fees in 2003 included $7,000 for assistance with and documentation of the Company's internal controls over financial reporting.

Tax Fees

Aggregate fees billed for tax-related services in 2003 were $103,000. Of this amount, $77,000 related to tax consulting services and $26,000 related to the review of our internally prepared tax returns. Aggregate fees billed for tax-related services in 2002 were $182,000. Of this amount, $126,000 related to tax consulting services and $56,000 related to the review of our internally prepared tax returns.

All Other Fees

In 2003, PricewaterhouseCoopers LLP provided the Company with an accounting research information service for a fee of $1,000. There were no fees for other services in 2002.

The Audit Committee pre-approves all audit and non-audit services provided by the Company's independent auditor prior to the engagement of the independent auditor with respect to such services. In addition to separately approved services, the Audit Committee's pre-approval policy provides for pre-approval of specifically described audit and non-audit services on an annual basis. The policy authorizes the Committee to delegate to one or more of its members pre-approval authority with respect to permitted services. None of the services described above were approved by the Audit Committee under the *de minimus* exception provided by Rule 2-01(c)(7)(i)(C) under Regulation S-X.

PART IV

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

(a) The following documents are filed as part of this report:

1. *Financial Statements.* Chesapeake's consolidated financial statements are included in Item 8 of this report. Reference is made to the accompanying Index to Financial Statements.

2. *Financial Statement Schedules.* Schedule II is included in Item 8 of this report with our consolidated financial statements. No other financial statement schedules are applicable or required.

3. *Exhibits.* The following exhibits are filed herewith pursuant to the requirements of Item 601 of Regulation S-K:

Exhibit Number	Description
3.1*	—Chesapeake's Restated Certificate of Incorporation together with the Certificates of Designation for the 6.75% Cumulative Convertible Preferred Stock of Chesapeake, the 6.0% Cumulative Convertible Preferred Stock and the 5.0% Cumulative Convertible Preferred Stock, the Certificate of Designation for the Series A Junior Participating Preferred Stock of Chesapeake, and the Certificates of Elimination filed November 4, 2002 and March 8, 2004 with the Secretary of State of the State of Oklahoma.
3.2*	—Chesapeake's Amended and Restated Bylaws.
4.1	—Indenture dated as of March 15, 1997 among Chesapeake, as issuer, Chesapeake Operating, Inc., Chesapeake Gas Development Corporation and Chesapeake Exploration Limited Partnership, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 7.875% Senior Notes due 2004. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's registration statement on Form S-4 (No. 333-24995). First Supplemental Indenture dated December 17, 1997 and Second Supplemental Indenture dated February 16, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's transition report on Form 10-K for the six months ended December 31, 1997. Second [Third] Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's registration statement on Form S-3 (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 1998. Fifth Supplemental Indenture dated November 19, 1999. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Sixth Supplemental Indenture dated December 31, 1999. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Seventh Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Eighth Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.1.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Ninth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546). Tenth Supplemental Indenture dated as of June 28, 2002. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Eleventh Supplemental Indenture dated as of July 8, 2002. Incorporated herein by reference to Exhibit 4.1.3 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Twelfth Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Thirteenth Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Fourteenth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.
4.2	—Indenture dated as of March 15, 1997 among Chesapeake, as issuer, Chesapeake Operating, Inc., Chesapeake Gas Development Corporation and Chesapeake Exploration Limited Partnership, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.5% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.3 to Chesapeake's registration statement on Form S-4 (No. 333-24995). First Supplemental Indenture dated December 17, 1997 and Second Supplemental Indenture dated February 16, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's transition report on Form 10-K for the six months ended December 31, 1997. Second [Third] Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's registration statement on Form S-3 (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 1998. Fifth Supplemental

Indenture dated November 19, 1999. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Sixth Supplemental Indenture dated December 31, 1999. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Seventh Supplement Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.2.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Eighth Supplement Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.2.3 to Chesapeake's registration statement of Form S-3 (No. 333-76545). Tenth Supplemental Indenture dated as of June 28, 2002. Incorporated herein by reference to Exhibit 4.2.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Eleventh Supplement Indenture dated as of July 8, 2002. Incorporated herein by reference to Exhibit 4.2.3 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Twelfth Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Thirteenth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Fourteenth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

4.3 —Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.125% Senior Notes due 2011. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Supplemental Indenture dated May 14, 2001. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Second Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Third Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Fourth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546). Fifth Supplemental Indenture dated as of June 28, 2002. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Sixth Supplemental Indenture dated July 8, 2002. Incorporated herein by reference to Exhibit 4.3.3 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Seventh Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Eighth Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Ninth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003 Tenth Supplemental Indenture dated as of March ___, 2004 to Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as subsidiary guarantors and the Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to the 8.125% senior notes due 2011.

4.3.1* —Tenth Supplemental Indenture dated as of March ___, 2004 to Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to the 8.125% senior notes due 2011.

4.4 —Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 8.375% Senior Notes due 2008. Incorporated herein by reference to Exhibit 4.16 to Chesapeake's registration statement on Form S-4 (No. 333-74584). First Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.16.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546). Second Supplemental Indenture dated as of June 28, 2002. Incorporated herein by reference to Exhibit 4.4.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Third Supplemental Indenture dated as of July 8, 2002. Incorporated herein by reference to Exhibit 4.4.3 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Fourth Supplemental Indenture dated as of February 14, 2003.Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Fifth Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Sixth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

4.4.1* —Seventh Supplemental Indenture dated March ___, 2004 to Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 8.375% Senior Notes due 2008.

4.5 —Indenture dated as of August 12, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to its 9.0% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.14 to Chesapeake's registration statement on Form S-4 (No. 333-99289). First Supplemental Indenture dated as of February 14, 2003.Incorporated herein by reference to Exhibit 4.5.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Second Supplemental Indenture dated May 1, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003 Third Supplemental Indenture dated August 15, 2003. Incorporated herein by reference to Exhibit 4.5.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

4.5.1* —Fourth Supplemental Indenture dated March ___, 2004 to Indenture dated as of August 12, 2002 among Chesapeake, as issuer, subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to 9.0% Senior Notes due 2012.

4.6 —Indenture dated as of December 20, 2002 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to our 7.75% Senior Notes due 2015. Incorporated herein by reference to Exhibit 4.5 to Chesapeake's registration statement on Form S-4 (No. 333-102445) First Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's report on Form 10-K/A for the year ended December 31, 2002. Second Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Third Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

4.6.1* —Fourth Supplemental Indenture dated March ___, 2004 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 7.75% Senior Notes due 2015.

4.7 —Agreement to furnish copies of unfiled long-term debt Instruments. Incorporated herein by reference to Chesapeake's transition report on Form 10-K for the six months ended December 31, 1997.

4.8 —Third Amended and Restated Credit Agreement, dated as of May 30, 2003, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, BNP Paribas and SunTrust Bank, as Co-Syndication Agents, Credit Lyonnais New York Branch and Toronto Dominion (Texas), Inc., as Co-Documentation Agents and the several lenders from time to time parties thereto. Incorporated herein by reference to Exhibit 4.8 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2003.

4.9 —Indenture dated as of March 5, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to 7.5% Senior Notes due 2013. First Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Second Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

4.9.1* —Third Supplemental Indenture dated March ___, 2004 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 7.5% Senior Notes due 2013

4.10 —Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to 6.875% senior notes due 2016. Incorporated herein by reference to Exhibit 4.2 to Chesapeake's registration statement on Form S-4/A (No. 333-110668).

4.10.1* —First Supplemental Indenture dated March ___, 2004 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to 6.875% senior notes due 2016.

4.15 —Warrant Registration Rights Agreement dated as of April 21, 1998 among Gothic Energy Corporation and purchasers of units consisting of its 14 1/8% senior secured discount notes due 2006 and warrants to purchase its common stock. Incorporated herein by reference to Exhibit 4.15 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.

10.1.1* —Chesapeake's 2003 Stock Incentive Plan. Incorporated herein by reference to Exhibit A to Chesapeake's definitive proxy statement for its 2003 annual meeting of shareholders filed April 17, 2003.

10.1.2† —Chesapeake's 1992 Nonstatutory Stock Option Plan, as Amended. Incorporated herein by reference to Exhibit 10.1.2

to Chesapeake's quarterly report on Form 10-Q for the quarter ended December 31, 1996.

10.1.3† —Chesapeake's 1994 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended December 31, 1996.

10.1.4† —Chesapeake's 1996 Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 1996 annual meeting of shareholders.

10.1.5† —Chesapeake's 1999 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.5 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 1999.

10.1.6† —Chesapeake's 2000 Employee Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2000.

10.1.7† —Chesapeake's 2000 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.7 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2000

10.1.8† —Chesapeake's 2001 Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 2001 annual meeting of shareholders filed April 30, 2001

10.1.9† —Chesapeake's 2001 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.9 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001.

10.1.10† —Chesapeake's 2001 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.10 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001.

10.1.11† —Chesapeake's 2002 Stock Option Plan. Incorporated herein by reference to Exhibit A to Chesapeake's definitive proxy statement for its 2002 annual meeting of shareholders filed April 29, 2002.

10.1.12† —Chesapeake's 2002 Non-Employee Director Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 2002 annual meeting of shareholders filed April 29, 2002

10.1.13† —Chesapeake's 2002 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.11 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2002.

10.1.14† —Chesapeake's 2003 Stock Award Plan for Non-Employee Directors. Incorporated herein by reference to Exhibit 10.1.14 to Chesapeake's annual report of Form 10-K/A for the year ended December 31, 2002.

10.1.15† —Chesapeake Energy Corporation 401(k) Make-Up Plan. Incorporated herein by reference to Exhibit 10.1.15 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002

10.1.16† —Chesapeake Energy Corporation Deferred Compensation Plan. Incorporated herein by reference to Exhibit 10.1.16 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002.

10.2.1†* —Third Amended and Restated Employment Agreement dated as of January 1, 2004, between Aubrey K. McClendon and Chesapeake Energy Corporation.

10.2.2†* —Third Amended and Restated Employment Agreement dated as of January 1, 2004, between Tom L. Ward and Chesapeake Energy Corporation.

10.2.3† —Amended and Restated Employment Agreement dated as of July 1, 2003 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

10.2.8† —Employment Agreement dated as of July 1, 2003 between Michael A. Johnson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

10.2.9† —Employment Agreement dated as of July 1, 2003 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.9 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

10.3† —Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries. Incorporated herein by reference to Exhibit 10.30 to Chesapeake's registration statement on Form S-1 (No. 33-55600).

10.5† —Rights Agreement dated July 15, 1998 between Chesapeake and UMB Bank, N.A., as Rights Agent. Incorporated herein by reference to Exhibit 1 to Chesapeake's registration statement on Form 8-A filed July 16, 1998. Amendment No. 1 dated September 11, 1998. Incorporated herein by reference to Exhibit 10.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 1998.

10.10 —Partnership Agreement of Chesapeake Exploration Limited Partnership dated December 27, 1994 between Chesapeake Energy Corporation and Chesapeake Operating, Inc. Incorporated herein by reference to Exhibit 10.10 to Chesapeake's registration statement on Form S-4 (No. 33-93718).

10.11 —Amended and Restated Limited Partnership Agreement of Chesapeake Louisiana, L.P. dated June 30, 1997 between Chesapeake Operating, Inc. and Chesapeake Energy Louisiana Corporation.

12* —Ratios of Earnings to Fixed Charges and Preferred Dividends.

21* — Subsidiaries of Chesapeake.

31.1* —Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2* —Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1* —Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

32.2* —Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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* Filed herewith.

† Management contract or compensatory plan or arrangement.

(b) Reports on Form 8-K

During the quarter ended December 31, 2003, Chesapeake filed the following current reports on Form 8-K:

On October 7, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on October 6, 2003 announcing our third quarter 2003 earnings release and conference call dates.

On October 30, 2003 we filed a current report on Form 8-K, furnishing under Item 12 a press release we issued on October 30, 2003 announcing financial and operating results for the third quarter of 2003, significant additions to our oil and natural gas hedging positions, $200 million of acquisitions of natural gas properties and updated 2003 and 2004 guidance.

On November 12, 2003, we filed a current report on Form 8-K, furnishing under Item 9 a press release we issued on November 11, 2003 announcing a $150 million cumulative convertible preferred stock offering.

On November 12, 2003, we filed a current report on Form 8-K, furnishing under Item 9 a press release we issued on November 11, 2003 announcing a cash tender offer and consent solicitation for our 8.50% senior notes due 2012.

On November 12, 2003, we filed a current report on Form 8-K, furnishing under Item 9 a press release we issued on November 11, 2003 announcing a private offering of senior notes and possible exchange offer.

On November 13, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on November 12, 2003 announcing the pricing of $200 million of 6.875% senior notes due 2016 and the pricing of $150 million of 5% cumulative convertible preferred stock. In addition, we also furnished under Item 9 that we updated the 2003 and 2004 guidance on our website.

On November 18, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we entered into an underwriting agreement on November 12, 2003 with Lehman Brothers Inc., Banc of America Securities LLC and Morgan Stanley & Co. Incorporated, as Representative of the Several Underwriters in connection with the issuance and sale of 1,725,000 shares of our 5.00% cumulative convertible preferred stock. In addition, we filed the underwriting agreement and the certificate of designation for the 5.00% cumulative convertible preferred stock under Item 7.

On November 26, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on November 25, 2003 announcing that, pursuant to our cash tender offer and consent solicitation for our 8.5% senior notes due 2012, we received the consents necessary to adopt certain proposed amendments to the indenture governing the notes.

On November 26, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on November 26, 2003 announcing the completion of the private placement of our 6.875% senior notes due 2016 and the acceptance of $104,845,000 principal amount of our 8.5% senior notes due 2012, tendered for early payment.

On December 2, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 1, 2003 announcing an exchange offer for our 8.125% senior notes due 2011.

On December 12, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 11, 2003 announcing the expiration of the cash tender offer for our 8.5% senior notes due 2012.

On December 16, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 15, 2003 announcing the declaration of quarterly common and preferred stock dividends.

On December 16, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 15, 2003 announcing early results of our exchange offer for our 8.125% senior notes due 2011.

On December 23, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued two press releases on December 22, 2003 announcing $510 million of acquisitions, updates to our hedging positions and our intention to extend the expiration date of our exchange offer for our 8.125% senior notes due 2011. In addition, we furnished under Item 9 additional information concerning the proposed acquisitions, additional hedging information and updates to our 2004 production forecasts.

On December 24, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 24, 2003 announcing the extension of our exchange offer for our 8.125% senior notes due 2011.

SIGNATURES

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

CHESAPEAKE ENERGY CORPORATION

By /S/ AUBREY K. MCCLENDON

Aubrey K. McClendon
Chairman of the Board and
Chief Executive Officer

Date: March 15, 2004

Exhibits 31.1
CERTIFICATION

I, Aubrey K. McClendon, certify that:

1. I have reviewed this annual report on Form 10-K of Chesapeake Energy Corporation;

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

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

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

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) disclosed in this report any change is the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to affect, the registrant's internal control over financial reporting; and

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

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2004

By: /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon
Chairman and Chief Executive Officer

Exhibit 31.2
CERTIFICATION

I, Marcus C. Rowland, certify that:

1. I have reviewed this amended report on Form 10-K of Chesapeake Energy Corporation;

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

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

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

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) disclosed in this report any change is the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to affect, the registrant's internal control over financial reporting; and

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

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2004

By: /s/ MARCUS C. ROWLAND
Marcus C. Rowland
Executive Vice President and Chief Financial Officer

INDEX TO EXHIBITS

Exhibit Number	Description
3.1*	—Chesapeake's Restated Certificate of Incorporation together with the Certificates of Designation for the 6.75% Cumulative Convertible Preferred Stock of Chesapeake, the 6.0% Cumulative Convertible Preferred Stock and the 5.0% Cumulative Convertible Preferred Stock, the Certificate of Designation for the Series A Junior Participating Preferred Stock of Chesapeake, and the Certificates of Elimination filed November 4, 2002 and March 8, 2004 with the Secretary of State of the State of Oklahoma.
3.2	—Chesapeake's Amended and Restated Bylaws.
4.1	—Indenture dated as of March 15, 1997 among Chesapeake, as issuer, Chesapeake Operating, Inc., Chesapeake Gas Development Corporation and Chesapeake Exploration Limited Partnership, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 7.875% Senior Notes due 2004. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's registration statement on Form S-4 (No. 333-24995). First Supplemental Indenture dated December 17, 1997 and Second Supplemental Indenture dated February 16, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's transition report on Form 10-K for the six months ended December 31, 1997. Second [Third] Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's registration statement on Form S-3 (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 1998. Fifth Supplemental Indenture dated November 19, 1999. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Sixth Supplemental Indenture dated December 31, 1999. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Seventh Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Eighth Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.1.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Ninth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546). Tenth Supplemental Indenture dated as of June 28, 2002. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Eleventh Supplemental Indenture dated as of July 8, 2002. Incorporated herein by reference to Exhibit 4.1.3 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Twelfth Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Thirteenth Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Fourteenth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.
4.2	—Indenture dated as of March 15, 1997 among Chesapeake, as issuer, Chesapeake Operating, Inc., Chesapeake Gas Development Corporation and Chesapeake Exploration Limited Partnership, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.5% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.3 to Chesapeake's registration statement on Form S-4 (No. 333-24995). First Supplemental Indenture dated December 17, 1997 and Second Supplemental Indenture dated February 16, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's transition report on Form 10-K for the six months ended December 31, 1997. Second [Third] Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's registration statement on Form S-3 (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 1998. Fifth Supplemental Indenture dated November 19, 1999. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Sixth Supplemental Indenture dated December 31, 1999. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Seventh Supplement Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.2.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Eighth Supplement Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.2.3 to Chesapeake's registration statement of Form S-3 (No. 333-76545). Tenth Supplemental Indenture dated as of June 28, 2002. Incorporated herein by reference to Exhibit 4.2.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Eleventh Supplement Indenture dated as of July 8, 2002. Incorporated herein by reference to Exhibit 4.2.3 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Twelfth Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's annual report on Form

10-K/A for the year ended December 31, 2002. Thirteenth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Fourteenth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

4.3 —Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.125% Senior Notes due 2011. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Supplemental Indenture dated May 14, 2001. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Second Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Third Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Fourth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546). Fifth Supplemental Indenture dated as of June 28, 2002. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Sixth Supplemental Indenture dated July 8, 2002. Incorporated herein by reference to Exhibit 4.3.3 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Seventh Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Eighth Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Ninth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003 Tenth Supplemental Indenture dated as of March ___, 2004 to Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as subsidiary guarantors and the Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to the 8.125% senior notes due 2011.

4.3.1 —Tenth Supplemental Indenture dated as of March ___, 2004 to Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to the 8.125% senior notes due 2011.

4.4 —Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 8.375% Senior Notes due 2008. Incorporated herein by reference to Exhibit 4.16 to Chesapeake's registration statement on Form S-4 (No. 333-74584). First Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.16.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546). Second Supplemental Indenture dated as of June 28, 2002. Incorporated herein by reference to Exhibit 4.4.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Third Supplemental Indenture dated as of July 8, 2002. Incorporated herein by reference to Exhibit 4.4.3 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Fourth Supplemental Indenture dated as of February 14, 2003.Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Fifth Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Sixth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

4.4.1 —Seventh Supplemental Indenture dated March ___, 2004 to Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 8.375% Senior Notes due 2008.

4.5 —Indenture dated as of August 12, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to its 9.0% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.14 to Chesapeake's registration statement on Form S-4 (No. 333-99289). First Supplemental Indenture dated as of February 14, 2003.Incorporated herein by reference to Exhibit 4.5.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Second Supplemental Indenture dated May 1, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003 Third Supplemental Indenture dated August 15, 2003. Incorporated herein by reference to Exhibit 4.5.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

4.5.1 —Fourth Supplemental Indenture dated March ___, 2004 to Indenture dated as of August 12, 2002 among Chesapeake, as issuer, subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to 9.0% Senior Notes due 2012.

4.6 —Indenture dated as of December 20, 2002 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to our 7.75% Senior Notes due 2015. Incorporated herein by reference to Exhibit 4.5 to Chesapeake's registration statement on Form S-4 (No. 333-102445) First Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's report on Form 10-K/A for the year ended December 31, 2002. Second Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Third Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

4.6.1 —Fourth Supplemental Indenture dated March ___, 2004 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 7.75% Senior Notes due 2015.

4.7 —Agreement to furnish copies of unfiled long-term debt Instruments. Incorporated herein by reference to Chesapeake's transition report on Form 10-K for the six months ended December 31, 1997.

4.8 —Third Amended and Restated Credit Agreement, dated as of May 30, 2003, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, BNP Paribas and SunTrust Bank, as Co-Syndication Agents, Credit Lyonnais New York Branch and Toronto Dominion (Texas), Inc., as Co-Documentation Agents and the several lenders from time to time parties thereto. Incorporated herein by reference to Exhibit 4.8 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2003.

4.9 —Indenture dated as of March 5, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to 7.5% Senior Notes due 2013. First Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Second Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

4.9.1 —Third Supplemental Indenture dated March ___, 2004 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 7.5% Senior Notes due 2013

4.10 —Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to 6.875% senior notes due 2016. Incorporated herein by reference to Exhibit 4.2 to Chesapeake's registration statement on Form S-4/A (No. 333-110668).

4.10.1 —First Supplemental Indenture dated March ___, 2004 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to 6.875% senior notes due 2016.

4.15 —Warrant Registration Rights Agreement dated as of April 21, 1998 among Gothic Energy Corporation and purchasers of units consisting of its 14 1/8% senior secured discount notes due 2006 and warrants to purchase its common stock. Incorporated herein by reference to Exhibit 4.15 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.

10.1.1 —Chesapeake's 2003 Stock Incentive Plan. Incorporated herein by reference to Exhibit A to Chesapeake's definitive proxy statement for its 2003 annual meeting of shareholders filed April 17, 2003.

10.1.2† —Chesapeake's 1992 Nonstatutory Stock Option Plan, as Amended. Incorporated herein by reference to Exhibit 10.1.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended December 31, 1996.

10.1.3† —Chesapeake's 1994 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended December 31, 1996.

10.1.4† —Chesapeake's 1996 Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 1996 annual meeting of shareholders.

10.1.5† —Chesapeake's 1999 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.5 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 1999.

10.1.6† —Chesapeake's 2000 Employee Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2000.

10.1.7† —Chesapeake's 2000 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.7 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2000

10.1.8† —Chesapeake's 2001 Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 2001 annual meeting of shareholders filed April 30, 2001

10.1.9† —Chesapeake's 2001 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.9 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001.

10.1.10† —Chesapeake's 2001 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.10 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001.

10.1.11† —Chesapeake's 2002 Stock Option Plan. Incorporated herein by reference to Exhibit A to Chesapeake's definitive proxy statement for its 2002 annual meeting of shareholders filed April 29, 2002.

10.1.12† —Chesapeake's 2002 Non-Employee Director Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 2002 annual meeting of shareholders filed April 29, 2002

10.1.13† —Chesapeake's 2002 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.11 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2002.

10.1.14† —Chesapeake's 2003 Stock Award Plan for Non-Employee Directors. Incorporated herein by reference to Exhibit 10.1.14 to Chesapeake's annual report of Form 10-K/A for the year ended December 31, 2002.

10.1.15† —Chesapeake Energy Corporation 401(k) Make-Up Plan. Incorporated herein by reference to Exhibit 10.1.15 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002

10.1.16† —Chesapeake Energy Corporation Deferred Compensation Plan. Incorporated herein by reference to Exhibit 10.1.16 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002.

10.2.1†* —Third Amended and Restated Employment Agreement dated as of January 1, 2004, between Aubrey K. McClendon and Chesapeake Energy Corporation.

10.2.2†* —Third Amended and Restated Employment Agreement dated as of January 1, 2004, between Tom L. Ward and Chesapeake Energy Corporation.

10.2.3† —Amended and Restated Employment Agreement dated as of July 1, 2003 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

10.2.8† —Employment Agreement dated as of July 1, 2003 between Michael A. Johnson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

10.2.9† —Employment Agreement dated as of July 1, 2003 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.9 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.

10.3† —Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries. Incorporated herein by reference to Exhibit 10.30 to Chesapeake's registration statement on Form S-1 (No. 33-55600).

10.5† —Rights Agreement dated July 15, 1998 between Chesapeake and UMB Bank, N.A., as Rights Agent. Incorporated herein by reference to Exhibit 1 to Chesapeake's registration statement on Form 8-A filed July 16, 1998. Amendment No. 1 dated September 11, 1998. Incorporated herein by reference to Exhibit 10.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 1998.

10.10 —Partnership Agreement of Chesapeake Exploration Limited Partnership dated December 27, 1994 between Chesapeake Energy Corporation and Chesapeake Operating, Inc. Incorporated herein by reference to Exhibit 10.10 to Chesapeake's registration statement on Form S-4 (No. 33-93718).

10.11 —Amended and Restated Limited Partnership Agreement of Chesapeake Louisiana, L.P. dated June 30, 1997 between Chesapeake Operating, Inc. and Chesapeake Energy Louisiana Corporation.

12* —Ratios of Earnings to Fixed Charges and Preferred Dividends.

21* —Subsidiaries of Chesapeake.

31.1* —Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2* —Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1* —Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2* —Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

† Management contract or compensatory plan or arrangement.

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Chesapeake Energy Corporation (the "Company") on Form 10-K for the period ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Aubrey K. McClendon, Chairman and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ AUBREY K. MCCLENDON
Aubrey K. McClendon
Chairman and Chief Executive Officer

Date: March 15, 2004

Exhibit 32.2

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Chesapeake Energy Corporation (the "Company") on Form 10-K for the period ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Marcus C. Rowland, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ MARCUS C. ROWLAND
Marcus C. Rowland
Executive Vice President and Chief Financial Officer

Date: March 15, 2004