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, 2002

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

Commission File No. 1-13726

Chesapeake Energy Corporation
(Exact Name of Registrant as Specified in Its Charter)

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

(405) 848-8000
Registrant's telephone number, including area code

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $.01	New York Stock Exchange
7.875% Senior Notes due 2004	New York Stock Exchange
8.375% Senior Notes due 2008	New York Stock Exchange
8.125% Senior Notes due 2011	New York Stock Exchange
8.5% Senior Notes due 2012	New York Stock Exchange
6.75% Cumulative Convertible Preferred Stock	New York Stock Exchange

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

None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES ☒ 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, 2002 was $1,054,315,346. At February 24, 2003, there were 190,782,300 shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of our definitive proxy statement for the 2003
annual meeting of shareholders are incorporated by reference in Part III

PART I

ITEM 1. *Business*

General

We are one of the ten largest independent natural gas producers in the United States. 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*, or on the Securities and Exchange Commission website at *www.sec.gov*, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

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

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

Recent Developments

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

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

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

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

On February 24, 2003, we announced a proposed private placement of $300 million in aggregate principal amount of senior notes, a proposed public offering of 20,000,000 shares of common stock pursuant to our existing shelf registration statement and a proposed private placement of $200 million of convertible preferred stock. There is no assurance these proposed offerings will be completed or, if they are completed, that they will be completed for the amount contemplated.

Business Strategy

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

- *Consistently Making High-Quality Acquisitions*. Our acquisition program is focused on small to medium-sized acquisitions of Mid-Continent natural gas properties that provide high-quality production and significant drilling opportunities. Since January 1, 2000, we have acquired or have signed agreements to acquire $1.9 billion of such properties (primarily in 17 separate transactions of greater than $10 million each) at an estimated average cost of $1.23 per mcfe of proved reserves. Each of these acquisitions either increased our ownership in existing wells or fields or added additional drilling locations in our core Mid-Continent operating area. We believe we are acquiring high-quality assets from El Paso and Vintage, distinguished by proved reserves that are 96% gas and 70% proved developed. We believe these properties provide substantial opportunities for additional drilling and improvement of operational efficiencies. The El Paso and Vintage properties complement our existing Mid-Continent assets, with 96% and 88%, respectively, of their proved reserves located in townships where we presently own properties. Because the Mid-Continent region contains many small companies seeking market liquidity and larger companies seeking to divest non-core assets, we expect to find additional attractive acquisition opportunities in the future.
- *Consistently Growing through the Drillbit*. One of our most distinctive characteristics is our ability to increase reserves through the drillbit. We are conducting one of the five most active drilling programs in the United States with our program focused on finding gas in the Mid-Continent region. We currently have 31 rigs drilling on Chesapeake-operated prospects, and we are participating in approximately 50 wells being drilled by others. Our Mid-Continent drilling program is the most active in the region and is supported by our ownership of an extensive land and 3-D seismic base.
- *Consistently Focusing on the Mid-Continent*. In this region, we believe we are the largest natural gas producer, the most active driller and the most active acquirer of undeveloped leases and producing properties. We believe the Mid-Continent region, which trails only the Gulf Coast and Rocky Mountain basins in U.S. gas production, has many attractive characteristics. These characteristics include long-lived natural gas properties with relatively predictable decline curves; multi-pay geological targets that decrease drilling risk, resulting in our historical Mid-Continent drilling success rate of over 95%; relatively high natural gas prices, typically only 10 to 20 cents per mmbtu behind Henry Hub index prices; generally lower service costs than in more competitive or more remote basins; and a favorable regulatory environment with virtually no federal land ownership. In addition, we believe the location of our headquarters in Oklahoma City provides us with many competitive advantages over other companies that direct their activities in this region from district offices in Oklahoma City or Tulsa or from out-of-state headquarters.
- *Consistently Focusing on Low Costs*. By minimizing operating costs, we have been able to deliver consistently attractive financial returns through all phases of the commodity price cycle. We believe our general and administrative costs and our lease operating expenses are among the lowest in the industry. We believe these low costs are the result of our management's effective cost-control programs, our high-quality asset base and the extensive and competitive services, gas processing and transportation infrastructures in the Mid-Continent. We believe the ONEOK, El Paso and Vintage acquisitions should reduce our overall operating cost structure per mcfe because our production costs per mcfe for these properties are expected to be lower than our current production costs per mcfe. We believe further operating efficiencies can be achieved through our acquisition of these properties.

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

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

Company Strengths

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

- *High-Quality Asset Base*. Our producing properties are characterized by long-lived reserves, established production profiles and an emphasis on natural gas. Based upon current production and reserve levels (and pro forma for the El Paso and Vintage acquisitions), our proved reserves-to-production ratio, or reserve life, is approximately 11.8 years. We estimate the El Paso properties have a reserve life of approximately 13 years and the Vintage properties approximately 17 years. In each of our operating areas, our properties are concentrated in locations that enable us to establish substantial economies of scale in drilling and production operations and facilitate the application of more effective reservoir management practices. We intend to continue building our Mid-Continent asset base by concentrating both our drilling and acquisition efforts in this region.
- *Low-Cost Producer*. Our high-quality asset base has enabled us to achieve a low operating cost structure. During 2002, our cash operating costs per unit of production were $0.81 per mcfe, which consisted of general and administrative expenses of $0.10 per mcfe, production expenses of $0.54 per mcfe and production taxes of $0.17 per mcfe. We believe this is one of the lowest operating cost structures among publicly traded independent oil and natural gas producers. We believe the El Paso and Vintage acquisitions should lower our cash operating costs because we project these properties will have production expenses of approximately $0.25 per mcfe. In addition, we believe the El Paso and Vintage acquisitions will lower our overall general and administrative expenses because we expect overhead recovery fees from third parties to more than offset any additional general and administrative expenses associated with managing the acquired assets. We currently operate approximately 77% of our proved reserves. This large percentage of operational control provides us with a high degree of operating flexibility and cost control. The El Paso and Vintage acquisitions will add 660 additional operated wells and will increase our ownership in 174 wells we presently operate.
- *Successful Acquisition Program*. Our experienced asset acquisition team focuses on adding to our attractive resource base in the Mid-Continent region. This area is characterized by long-lived natural gas reserves, low lifting costs, multiple geological targets that provide substantial drilling potential, favorable basis differentials to benchmark commodity prices, a well-developed oil and gas transportation infrastructure and considerable potential for further consolidation of assets. Since 1998 and following the completion of the El Paso and Vintage acquisitions, we will have completed $2.7 billion in acquisitions at an average cost of $1.12 per mcfe of proved reserves. We believe we are well-positioned to continue this consolidation as a result of our large existing asset base, our corporate presence in Oklahoma, our knowledge and expertise in the Mid-Continent region and current trends in the industry. We believe the El Paso and Vintage acquisitions are examples of the application of our

acquisition strategy. These properties have a large percentage of proved developed gas reserves with low operating costs, significant operating and undeveloped drilling upside and are located in areas where currently we have a substantial operating presence. We plan to pursue acquisitions of properties with similar characteristics in the future.

- *Large Inventory of Drilling Projects*. During the past 14 years, we believe we have been one of the ten most active drillers in the United States and the most active driller in the Mid-Continent. We believe we have developed a particular expertise in drilling deep vertical and horizontal wells in search of large natural gas accumulations in challenging reservoir conditions. We actively pursue deep drilling targets because of our view that most undiscovered gas reserves in the Mid-Continent will be found at depths below 12,500 feet. In addition, we believe that our large 3-D seismic inventory, much of which is proprietary to Chesapeake, provides us with an advantage over our competitors, which largely prefer to drill shallower development wells. As a result of our aggressive land acquisition strategies and Oklahoma's favorable forced-pooling regulations, we have been able to accumulate an onshore leasehold position of approximately 2.0 million net acres as of December 31, 2002. In addition, our technical teams have identified over 1,500 exploratory and developmental drillsites, representing more than five years of future drilling opportunities at our current rate of drilling. The El Paso and Vintage acquisitions will add to our existing land inventory and we have identified more than 300 additional potential drillsites associated with the properties to be acquired in these pending acquisitions.
- *Hedging Program*. We have historically used and intend to continue using hedging programs to reduce the risks inherent in producing oil and natural gas, commodities that are extremely volatile in price. We believe this volatility is likely to continue and may even accelerate in the years ahead. We believe that a producer can use this volatility to its benefit by taking advantage of prices when they exceed historical norms. Over the past two years, we increased our oil and gas revenues by $201 million through hedging. We currently have gas hedging positions covering 116 bcf for 2003 at an average price of $4.70 per mcf. In addition, we have 90% of our projected oil production hedged for 2003 at an average NYMEX price of $27.78 per barrel of oil.
- *Entrepreneurial Management*. Our management team formed Chesapeake in 1989 with an initial capitalization of $50,000. Through the following years, this management team has guided our company through operational challenges and extremes of oil and gas prices to create one of the ten largest independent natural gas producers in the United States. The company's co-founders, Aubrey K. McClendon and Tom L. Ward, have been business partners in the oil and gas industry for 20 years and beneficially own approximately 11.1 million and 12.5 million of our common shares, respectively.

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Drilling Activity

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

	Years Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
United States						
Development:						
Productive	617	237.7	423	196.9	291	142.7
Non-productive	34	11.5	36	12.2	12	5.3
Total	651	249.2	459	209.1	303	148.0
Exploratory:						
Productive	47	24.6	36	18.4	32	17.0
Non-productive	10	5.4	17	9.0	11	5.4
Total	57	30.0	53	27.4	43	22.4
Canada(1)						
Development:						
Productive	—	—	17	7.6	12	6.1
Non-productive	—	—	1	0.4	2	0.8
Total	—	—	18	8.0	14	6.9

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

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

Well Data

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

Production, Sales, Prices and Expenses

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

	Years Ended December 31,								
	2002			2001			2000		
	U.S.	Canada	Combined	U.S.	Canada	Combined	U.S.	Canada	Combined
Net Production:									
Oil (mbbl)	3,466	—	3,466	2,880	—	2,880	3,068	—	3,068
Gas (mmcf)	160,682	—	160,682	135,096	9,075	144,171	103,694	12,077	115,771
Gas equivalent (mmcfe)	181,478	—	181,478	152,376	9,075	161,451	122,102	12,077	134,179
Oil and Gas Sales ($ in thousands):									
Oil	$ 87,403	$ —	$ 87,403	$ 77,522	$ —	$ 77,522	$ 80,953	$ —	$ 80,953
Gas	568,051	—	568,051	626,079	31,928	658,007	355,391	33,826	389,217
Total oil and gas sales	$ 655,454	$ —	$ 655,454	$ 703,601	$ 31,928	$ 735,529	$ 436,344	$ 33,826	$ 470,170
Average Sales Price:									
Oil ($ per bbl)	$ 25.22	$ —	$ 25.22	$ 26.92	$ —	$ 26.92	$ 26.39	$ —	$ 26.39
Gas ($ per mcf)	$ 3.54	$ —	$ 3.54	$ 4.63	$ 3.52	$ 4.56	$ 3.43	$ 2.80	$ 3.36
Gas equivalent ($ per mcfe)	$ 3.61	$ —	$ 3.61	$ 4.62	$ 3.52	$ 4.56	$ 3.57	$ 2.80	$ 3.50
Expenses ($ per mcfe):									
Production expenses	$ 0.54	$ —	$ 0.54	$ 0.48	$ 0.26	$ 0.47	$ 0.38	$ 0.32	$ 0.37
Production taxes	$ 0.17	$ —	$ 0.17	$ 0.22	$ —	$ 0.20	$ 0.20	$ —	$ 0.19
General and administrative	$ 0.10	$ —	$ 0.10	$ 0.09	$ 0.11	$ 0.09	$ 0.09	$ 0.17	$ 0.10
Depreciation, depletion and amortization	$ 1.22	$ —	$ 1.22	$ 1.08	$ 0.90	$ 1.07	$ 0.76	$ 0.71	$ 0.75

Our hedging activities resulted in an increase in oil and gas revenues of $96.0 million in 2002 compared to an increase of $105.4 million in 2001 and a decrease of $30.6 million in 2000.

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

Proved Reserves

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

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

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

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

Development, Exploration, Acquisition and Divestiture Activities

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

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

Acreage

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

	Developed		Undeveloped		Total Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	2,569,352	1,228,365	601,993	312,513	3,171,345	1,540,878
Gulf Coast	246,508	146,986	132,909	106,826	379,417	253,812
Permian Basin	66,134	50,144	77,602	48,024	143,736	98,168
Williston Basin	40,891	16,297	55,223	37,594	96,114	53,892
Other areas	9,737	4,891	26,879	19,699	36,616	24,589
Total	2,932,622	1,446,683	894,606	524,656	3,827,228	1,971,339

Marketing

Chesapeake’s oil production is sold under market sensitive or spot price contracts. Our natural gas production is sold to purchasers under percentage-of-proceeds or percentage-of-index contracts and by direct marketing to end users or aggregators. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after gathering and processing our gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. The revenue we receive from the sale of natural gas liquids is included in natural gas sales. Under percentage-of-index contracts, the price per mmbtu we receive for our gas at the wellhead is tied to indexes published in *Inside FERC* or *Gas Daily*. During 2002, sales to Continental Natural Gas, Duke Energy Field Services and Reliant Energy Field Services of $90.2 million, $71.4 million and $68.7 million, respectively, accounted for 35% of our total oil and gas sales. 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 oil and gas sales in 2002.

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

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 our oil and gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow from banks is subject to periodic redeterminations based on prices specified by our bank group at the time of redetermination. In addition, we may have ceiling test write-downs in the future if prices fall significantly.

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

- worldwide and domestic supplies of oil and gas;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- risks associated with owning and operating drilling rigs;
- the availability of pipeline capacity;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions; and
- the overall economic environment.

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

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

As of December 31, 2002, we had long-term indebtedness of $1.7 billion, none of which was bank indebtedness. As of February 21, 2003, we had long-term indebtedness of $1.76 billion, $104 million of which was bank indebtedness. Upon completion of our proposed offering of common stock and private placements of preferred stock and senior notes, we estimate that we will have $1.95 billion in long-term indebtedness, none of which will be bank indebtedness, plus preferred stock outstanding having an aggregate liquidation preference of $349.9 million. Our long-term indebtedness represented 65% of our total book capitalization at December 31, 2002. We expect to be highly leveraged in the foreseeable future.

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

- a significant portion of our cash flows must be used to service our indebtedness;
- a high level of debt increases our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, or other general corporate purposes.

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

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

Also, if our proposed securities offerings are not all successfully closed, we may need to use all or substantially all of our available bank borrowings to fund our pending acquisitions, which could substantially limit our liquidity.

Our industry is extremely competitive.

The energy industry is extremely competitive. This is especially true with regard to exploration for, and development and production of, new sources of oil and natural gas. As an independent producer of oil and natural gas, we frequently compete against companies that are larger and financially stronger in acquiring properties suitable for exploration, in contracting for drilling equipment and other services and in securing trained personnel.

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

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

- our production is less than expected;

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

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

Estimates of oil and gas reserves are uncertain and inherently imprecise.

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

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

At December 31, 2002, approximately 26% of our estimated proved reserves by volume were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. These reserve estimates include the assumption that we will make significant capital expenditures to develop the reserves, including $248 million in 2003. Although we have prepared estimates of our oil and gas reserves and the costs associated with these reserves in accordance with industry standards, the estimated costs may not be accurate, development may not occur as scheduled and results may not be as estimated.

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

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

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

If we do not make significant capital expenditures, we may not be able to replace 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, there can be no assurance that additional bank debt, debt or equity issuances or other methods of financing will be available to meet these requirements.

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

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

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities.

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

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

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. While it is our current intention to continue to concentrate on acquiring properties with development and exploration potential located in the Mid-Continent region, there can be no assurance that in the future we will not decide to pursue acquisitions or properties located in other geographic regions. To the extent that such acquired properties are substantially different from our existing properties, our ability to efficiently realize the economic benefits of such transactions may be limited.

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

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

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

Oil and gas operations are subject to many risks, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, and other environmental 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. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover casualty losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

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

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

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements; and
- the high cost, or shortages or delays in the availability, of drilling rigs and equipment.

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

We depend, and will continue to depend in the foreseeable future, on the services of our officers and key employees with extensive experience and expertise in evaluating and analyzing producing oil and gas properties and drilling prospects, maximizing production from oil and gas properties, marketing oil and gas production, and developing and executing financing and hedging strategies. Our ability to retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business.

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

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

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

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

Regulation

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

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

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

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

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

Environmental Regulation. Various federal, state and local laws and regulations concerning the discharge of contaminants into the environment, the generation, storage, transportation and disposal of contaminants, and the protection of public health, natural resources, wildlife and the environment affect our exploration, development and production operations. We must take into account the cost of complying with environmental regulations in planning, designing, drilling, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products, water and air pollution control procedures, and the remediation of petroleum-product contamination. In addition, our operations require us to obtain permits for, among other things,

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

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

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

We have made and will continue to make expenditures to comply with environmental regulations and requirements. These are necessary business costs in the oil and gas industry. Although we are not fully insured against all environmental risks, we maintain insurance coverage which we believe is customary in the industry.

Moreover, it is possible that other developments, such as stricter and more comprehensive environmental laws and regulations, as well as claims for damages to property or persons resulting from company operations, could result in substantial costs and liabilities, including civil and criminal penalties, to Chesapeake. We believe we are in substantial compliance with existing environmental regulations, and that, absent the occurrence of an extraordinary event the effect of which cannot be predicted, any noncompliance will not have a material adverse effect on our operations or earnings.

Income Taxes

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

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

In the event of an ownership change (as defined for income tax purposes), Section 382 of the Code imposes an annual limitation on the amount of a corporation’s taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Chesapeake had an ownership change in March 1998 which triggered a limitation. Certain NOLs acquired through various acquisitions are also subject to limitations. Of the $653 million NOLs and $300 million AMT NOLs, $346 million and $83 million, respectively, are limited under Section 382. Therefore, $307 million of the NOLs and $217 million of the AMT NOLs are not subject to the limitation. The utilization of $346 million of the NOLs and the utilization of $83 million of the AMT NOLs subject to the Section 382 limitation are limited to approximately $41 million and $15 million, respectively, each taxable year. Although no assurances can be made, we do not believe that an additional ownership change has occurred as of December 31, 2002. Equity transactions after the date hereof by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

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

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

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

Title to Properties

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

Operating Hazards and Insurance

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

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

Employees

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

Glossary

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of gas equivalent.

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

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

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

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

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

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

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

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

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

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

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

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

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

Mbtu. One thousand btus.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of gas equivalent.

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

NYMEX. New York Mercantile Exchange.

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.

Proved Reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Undeveloped 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 drilled to known reservoir on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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.

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.

ITEM 2. ***Properties***

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

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

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

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

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

Primary Operating Area

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

Secondary Operating Areas

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

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

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

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

Oil and Gas Reserves

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

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

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

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

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

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

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

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. Predictions about prices and future production levels are subject to great uncertainty, and 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.

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

Facilities

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

ITEM 3. ***Legal Proceedings***

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

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

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

Not applicable.

PART II

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

Price Range of Common Stock

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

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

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

Dividends

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

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

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

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

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	Years Ended December 31,				
	2002	2001	2000	1999	1998
	($ in thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Oil and gas sales	$ 655,454	$ 735,529	$ 470,170	$ 280,445	$ 256,887
Risk management income (loss)	(88,018)	84,789	—	—	—
Oil and gas marketing sales	170,315	148,733	157,782	74,501	121,059
Total revenues	737,751	969,051	627,952	354,946	377,946
Operating costs:					
Production expenses	98,191	75,374	50,085	46,298	51,202
Production taxes	30,101	33,010	24,840	13,264	8,295
General and administrative	17,618	14,449	13,177	13,477	19,918
Oil and gas marketing expenses	165,736	144,373	152,309	71,533	119,008
Oil and gas depreciation, depletion and amortization	221,189	172,902	101,291	95,044	146,644
Depreciation and amortization of other assets	14,009	8,663	7,481	7,810	8,076
Impairment of oil and gas properties	—	—	—	—	826,000
Impairment of other assets	—	—	—	—	55,000
Total operating costs	546,844	448,771	349,183	247,426	1,234,143
Income (loss) from operations	190,907	520,280	278,769	107,520	(856,197)
Other income (expense):					
Interest and other income	7,340	2,877	3,649	8,562	3,926
Interest expense	(111,280)	(98,321)	(86,256)	(81,052)	(68,249)
Loss on investment in Seven Seas	(17,201)	—	—	—	—
Loss on repurchases of debt	(2,626)	—	—	—	(13,334)
Impairments of investments in securities	—	(10,079)	—	—	—
Gain on sale of Canadian subsidiary	—	27,000	—	—	—
Gothic standby credit facility costs	—	(3,392)	—	—	—
Total other income (expense)	(123,767)	(81,915)	(82,607)	(72,490)	(77,657)
Income (loss) before income taxes and extraordinary item	67,140	438,365	196,162	35,030	(933,854)
Provision (benefit) for income taxes	26,854	174,959	(259,408)	1,764	—
Income (loss) before extraordinary item	40,286	263,406	455,570	33,266	(933,854)
Extraordinary item:					
Loss on early extinguishment of debt, net of applicable income taxes	—	(46,000)	—	—	—
Net income (loss)	40,286	217,406	455,570	33,266	(933,854)
Preferred stock dividends	(10,117)	(2,050)	(8,484)	(16,711)	(12,077)
Gain on redemption of preferred stock	—	—	6,574	—	—
Net income (loss) available to common shareholders	$ 30,169	$ 215,356	$ 453,660	$ 16,555	$ (945,931)
Earnings (loss) per common share—basic:					
Income (loss) before extraordinary item	$ 0.18	$ 1.61	$ 3.52	$ 0.17	$ (9.83)
Extraordinary item	—	(0.28)	—	—	(0.14)
Net income (loss)	$ 0.18	$ 1.33	$ 3.52	$ 0.17	$ (9.97)
Earnings (loss) per common share—assuming dilution:					
Income (loss) before extraordinary item	$ 0.17	$ 1.51	$ 3.01	$ 0.16	$ (9.83)
Extraordinary item	—	(0.26)	—	—	(0.14)
Net income (loss)	$ 0.17	$ 1.25	$ 3.01	$ 0.16	$ (9.97)
Cash dividends declared per common share	$ 0.06	$ —	$ —	$ —	$ 0.04
Cash Flow Data:					
Cash provided by operating activities before changes in working capital	$ 412,517	$ 518,563	$ 305,804	$ 138,727	$ 117,500
Cash provided by operating activities	432,531	553,737	314,640	145,022	94,639
Cash used in investing activities	779,745	670,105	325,229	153,908	548,050
Cash provided by (used in) financing activities	477,257	234,507	(27,740)	13,102	363,797
Effect of exchange rate changes on cash	—	(545)	(329)	4,922	(4,726)
Balance Sheet Data (at end of period):					
Total assets	$ 2,875,608	$ 2,286,768	$ 1,440,426	$ 850,533	$ 812,615
Long-term debt, net of current maturities	1,651,198	1,329,453	944,845	964,097	919,076
Stockholders’ equity (deficit)	907,875	767,407	313,232	(217,544)	(248,568)

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

Overview

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

	Years Ended December 31,		
	2002	2001	2000
Net Production:			
Oil (mbbl)	3,466	2,880	3,068
Gas (mmcf)	160,682	144,171	115,771
Gas equivalent (mmcfe)	181,478	161,451	134,179
Oil and Gas Sales ($ in thousands):			
Oil	$ 87,403	$ 77,522	$ 80,953
Gas	568,051	658,007	389,217
Total oil and gas sales	$ 655,454	$ 735,529	$ 470,170
Average Sales Price:			
Oil ($ per bbl)	$ 25.22	$ 26.92	$ 26.39
Gas ($ per mcf)	$ 3.54	$ 4.56	$ 3.36
Gas equivalent ($ per mcfe)	$ 3.61	$ 4.56	$ 3.50
Expenses ($ per mcfe):			
Production expenses and taxes	$ 0.71	$ 0.67	$ 0.56
General and administrative	$ 0.10	$ 0.09	$ 0.10
Depreciation, depletion and amortization	$ 1.22	$ 1.07	$ 0.75
Net Wells Drilled	279	245	177
Net Wells at End of Period	4,237	3,572	2,697

Recent Developments

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

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

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

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

On February 24, 2003, we announced a proposed private placement of $300 million in aggregate principal amount of senior notes, a proposed public offering of 20,000,000 shares of common stock pursuant to our existing shelf registration statement and a proposed private placement of $200 million of convertible preferred stock. There is no assurance these proposed offerings will be completed or, if they are completed, that they will be completed for the amount contemplated.

Results of Operations

General. For the year ended December 31, 2002, Chesapeake had net income of $40.3 million, or $0.17 per diluted common share, on total revenues of $737.8 million. This compares to net income of $217.4 million, or $1.25 per diluted common share, on total revenues of $969.1 million during the year ended December 31, 2001, and net income of $455.6 million, or $3.01 per diluted common share, on total revenues of $628.0 million during the year ended December 31, 2000. The 2002 net income includes, on a pre-tax basis, $88.0 million in risk management loss, 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 risk management income, a $10.1 million impairment of certain equity investments, a $27.0 million gain on the sale of our Canadian subsidiary, and a $3.4 million cost for an unsecured standby credit facility associated with the acquisition of Gothic Energy Corporation. There was also a $46.0 million extraordinary after-tax loss on early extinguishment of debt. Net income in 2000 was significantly enhanced by the reversal of a deferred tax valuation allowance in the amount of $265.0 million. The reversal related to Chesapeake’s expected ability to generate sufficient future taxable income to utilize net operating losses prior to their expiration.

Oil and Gas Sales. During 2002, oil and gas sales were $655.5 million versus $735.5 million in 2001 and $470.2 million in 2000. In 2002, Chesapeake produced 181.5 bcfe at a weighted average price of $3.61 per mcfe, compared to 161.5 bcfe produced in 2001 at a weighted average price of $4.56 per mcfe, and 134.2 bcfe produced in 2000 at a weighted average price of $3.50 per mcfe. The decline in prices in 2002 resulted in a decline in revenue of $172 million offset by $92 million due to increased production, for a net decrease in revenues of $80 million. The increase in 2001 revenues over 2000 of $265 million is due to increased prices ($171 million) and increased production ($94 million). The change in oil and gas prices has a significant impact on our oil and gas revenues and cash flows. Assuming the 2002 production levels, a change of $.10 per mcf would result in an increase/decrease in revenues and cash flow of approximately $16 million and $15 million, respectively, and a change of $1.00 per barrel would result in an increase/decrease in revenues and cash flows of approximately $3.5 million and $3.3 million, respectively, without considering the effect of hedging activities.

For 2002, we realized an average price per barrel of oil of $25.22, compared to $26.92 in 2001 and $26.39 in 2000. Natural gas prices realized per mcf were $3.54, $4.56 and $3.36 in 2002, 2001 and 2000, respectively. Our hedging activities resulted in an increase in oil and gas revenues of $96.0 million or $0.53 per mcfe in 2002, an increase of $105.4 million or $0.65 per mcfe in 2001 and a decrease of $30.6 million or $0.23 per mcfe in 2000.

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

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

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

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. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results of the hedged item in the consolidated statement of operations. 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. For derivative instruments designated as fair value hedges, changes in fair value, to the extent the hedge is effective, are recognized as an increase or decrease to the value of the hedged item until the hedged item is recognized in earnings. 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. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in earnings. Changes in fair value of contracts that do not meet the SFAS 133 definition of a cash flow hedge are also recognized in earnings through risk management income. See Hedging Activities below and Item 7A—Quantitative and Qualitative Disclosures about Market Risk for additional information regarding our hedging activities.

Risk Management Income (Loss). Chesapeake recognized $88.0 million of risk management loss in 2002 compared to $84.8 million of risk management income in 2001, and no such income (loss) in 2000. Risk management income for 2002 consisted of losses of $24.0 million related to changes in the fair value of derivatives not qualifying as cash flow hedges, $59.7 million of reclassifications of gains on the settlement of such contracts and $3.6 million associated with the ineffective portion of derivatives qualifying for cash flow hedge accounting. It also included a gain of $4.6 million related to changes in fair value of interest rate derivatives not qualifying for fair value hedge accounting, $1.8 million of reclassifications of gains on the settlement of interest rate swaps to interest expense, and a $3.5 million loss associated with the ineffective portion of our swaption. Risk management income for 2001 consisted of $106.8 million related to changes in fair value of derivatives not designated as cash flow hedges less $24.5 million of reclassifications related to the settlement of such contracts plus $2.5 million associated with the ineffective portion of derivatives qualifying for hedge accounting.

Pursuant to SFAS 133, our cap-swaps, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. Therefore, changes in fair value of these instruments that occur prior to their maturity, together with any change in fair value of cash flow hedges resulting from ineffectiveness, are reported in the consolidated statement of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive either SFAS 133 cash flow or fair value hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

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

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

Production Taxes. Production taxes were $30.1 million in 2002 compared to $33.0 million in 2001 and $24.8 million in 2000. On a unit of production basis, production taxes were $0.17, $0.20 and $0.19 per mcfe in 2002, 2001 and 2000, respectively. The decrease in 2002 of $2.9 million was due to a decrease in the average wellhead prices received for natural gas. The increase in 2001 of $8.2 million was due to an increase in production volumes and, to a lesser extent, an increase in the average wellhead prices received for natural gas. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and gas prices are higher. We expect production taxes per mcfe to range from $0.25 to $0.28 in 2003 based on our assumption that oil and natural gas wellhead prices will range from $4.00 to $4.50 per mcfe.

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

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

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

In connection with a legal proceeding brought against us by certain royalty owners, we determined that a portion of the marketing fee we had charged the royalty owners should be refunded. In late 2002, we deposited with the court $3.3 million to be held in an interest-bearing account for distribution to affected royalty owners which resulted in a charge to general and administrative expenses. A description of pending royalty owner litigation is included below under Liquidity and Capital Resources—Contingencies.

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

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

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

Interest Expense. Interest expense increased to $111.3 million in 2002, compared to $98.3 million in 2001 and $86.3 million in 2000. The increase in 2002 is due to a $264 million increase in average long-term borrowings in 2002 compared to 2001. The increase in 2001 is due to a $260 million increase in average long-term borrowings in 2001 compared to 2000, partially offset by a decrease in the overall average interest rate. In addition to the interest expense reported, we capitalized $5.0 million of interest during 2002, compared to $4.7 million capitalized in 2001, and $2.4 million capitalized in 2000 on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using the weighted average interest rate on our outstanding borrowings. We expect 2003 interest expense to be between $0.65 and $0.70 per mcfe.

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

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

In the third quarter of 2002, Chesapeake recorded an impairment of $4.8 million representing 100% of the cost allocated to our Seven Seas common stock warrants. During the fourth quarter of 2002, we recorded an additional impairment of $12.4 million to reduce our net investment in the senior secured notes, including accrued interest, to $7.5 million, representing Chesapeake’s anticipated share of the net proceeds from the liquidation of Seven Seas’ assets.

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

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

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

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

Extraordinary Loss on Early Extinguishment of 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 all $120.0 million principal amount of our 9.125% senior notes. These redemptions were done as a part of a refinancing of approximately 74% of our senior note debt and 72% of our total long-term debt outstanding. Even though we purchase our outstanding senior notes from time to time, the refinancing of the majority of our senior debt was an unusual non-recurring event and as such we have reported it as an extraordinary item in accordance with APB 30. See Recently Issued Accounting Standards within this Item 7. 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. These costs associated with early extinguishment of debt are reflected as a $46.0 million after-tax extraordinary loss in 2001.

Provision (Benefit) for Income Taxes. Chesapeake recorded income tax expense of $26.9 million in 2002, compared to income tax expense of $175.0 million in 2001 and income tax benefit of $259.4 million in 2000. All income tax expense for 2002 is related to our domestic operations. Income tax expense for 2001 is comprised of $158.3 million related to our domestic operations, $7.1 million related to our Canadian operations and $9.6 million related to the sale of our Canadian subsidiary. The income tax benefit in 2000 was comprised of $5.6 million of income tax expense related to our Canadian operations and the reversal of a $265 million deferred tax valuation allowance which was established in prior years. The valuation allowance had been established due to uncertainty surrounding our ability to utilize extensive regular tax NOLs prior to their expiration. Based upon our results of operations as of December 31, 2000, the improved outlook for the natural gas industry and our projected results of future operations, we believed it was more likely than not that Chesapeake would be able to generate sufficient future taxable income to utilize our existing NOLs prior to their expiration. Consequently, we determined that a valuation allowance was no longer required at December 31, 2000. As of December 31, 2001, we determined that it was more likely than not that $2.4 million of the deferred tax assets related to Louisiana net operating losses will not be realized and we recorded a valuation allowance equal to such amounts. Our expectations remain unchanged as of December 31, 2002.

Cash Flows From Operating, Investing and Financing Activities

Cash Flows from Operating Activities. Cash provided by operating activities (exclusive of changes in working capital) was $412.5 million in 2002, compared to $518.6 million in 2001 and $305.8 million in 2000.

The $106.1 million decrease from 2001 to 2002 was primarily due to decreased oil and gas revenues resulting from lower prices partially offset by higher volumes and the increase in 2001 over 2000 was due to significantly higher gas prices and higher volumes of both oil and gas.

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

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

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

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

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

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

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

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

Liquidity and Capital Resources

Sources of Liquidity

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

We believe we will have adequate resources, including budgeted operating cash flows, working capital and proceeds from our revolving bank credit facility, to fund our capital expenditure budget for drilling, land and seismic activities during 2003, which is currently estimated to be between $475 and $525 million. However, higher drilling and field operating costs, unfavorable drilling results or other factors could cause us to reduce our drilling program, which is largely discretionary. Based on our current cash flow assumptions, we expect operating cash flow to be between $600 million and $650 million. Any operating cash flow not needed to fund our drilling program will be available for acquisitions, debt repayment or other general corporate purposes in 2003.

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

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

Contractual Obligations

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

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

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

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

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

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

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

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

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

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

Investing and Financing Transactions

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

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

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

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

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

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

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

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

Contingencies

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

Application of Critical Accounting Policies

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

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

Hedging. From time to time, Chesapeake uses commodity price and financial risk management instruments to hedge our exposure to price fluctuations in oil and natural gas and interest rates. Recognized gains and losses on hedge contracts are reported as a component of the related transaction. Results of oil and gas hedging 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 cash flow or fair value hedges that occur prior to maturity are initially reported in the consolidated statement of operations as risk management income (loss). All amounts initially recorded in this caption are ultimately reversed within the same caption and included in oil and gas sales or interest expense, as applicable, over the respective contract terms.

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. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results of the hedged item in the consolidated statement of operations. 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. For derivative instruments designated as fair value hedges, changes in fair value, to the extent the hedge is effective, are recognized as an increase or decrease to the value of the hedged item until the hedged item is recognized in earnings. 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. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in earnings. Changes in fair value of contracts that do not meet the SFAS 133 definition of a cash flow or fair value hedge are also recognized in earnings through risk management income. 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, 2002 and 2001, the net market value of our derivatives was a liability of $45 million and an asset of $157 million, respectively. Risk management income (loss) for the years ended December 31, 2002 and 2001 was a loss of $88 million and a gain of $85 million, respectively. With respect to our derivatives held as of December 31, 2002, an increase or decrease in natural gas prices of $.25 per mmbtu would increase or decrease the estimated fair value of our derivatives by approximately $15.6 million. An increase or decrease in crude oil prices of $1.00 per barrel would increase or decrease the estimated fair value of our derivatives by approximately $3.5 million.

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

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

Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized. The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred. Unevaluated properties are grouped by major producing area where individual property costs are not significant and are assessed individually when individual costs are significant.

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

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

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

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

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

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

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

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

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

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

Hedging Activities

Oil and Gas Hedging

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2002, our oil and gas derivative instruments were comprised of swaps, cap-swaps and basis protection swaps. These instruments allow us to predict with greater certainty the oil and gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, 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, we receive a fixed price for the hedged commodity and pay a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure.

- Basis protection swaps are arrangements that guarantee a price differential of oil and 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.

From time to time, we close certain swap and cap-swap transactions designed to hedge a portion of our oil and natural gas production by entering into a counter-swap instrument. Under the counter-swap we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. To the extent the counter-swap, which does not qualify for hedge accounting under SFAS 133, is designed to lock the value of an existing SFAS 133 cash flow hedge, the net value of the swap and the counter-swap is frozen and shown as a derivative receivable or payable in the consolidated balance sheets. At the same time, the original swap is designated as a non-qualifying cash flow hedge under SFAS 133. The net receivable or payable is frozen until the related month of production and is then recognized as an increase or decrease to revenues. Changes in fair value occurring after the original swap has been designated as a non-qualifying cash flow hedge under SFAS 133 are included in results of operations. To the extent the counter-swap is designed to lock the value of a non-qualifying cash flow hedge under SFAS 133, the value of the counter-swap is shown as a derivative asset or liability in the consolidated balance sheet and referred to below as a fixed-price counter swap. Any changes in the fair value of the counter-swap are included in results of operations.

Pursuant to SFAS 133, our cap-swaps, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. Therefore, changes in the fair value of these instruments that occur prior to their maturity, together with any changes in fair value of cash flow hedges resulting from ineffectiveness, are reported in the consolidated statements of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive SFAS 133 cash flow hedge accounting treatment. All amounts initially recorded in this caption related to commodity derivatives are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

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

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

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

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

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

Risk management income (loss) related to our oil and gas derivatives is comprised of the following:

	December 31, 2002	December 31, 2001
	($ in thousands)	
Risk management income (loss):		
Change in fair value of derivatives not qualifying for hedge accounting	$ (23,979)	$ 106,825
Reclassification of gain on settled contracts	(59,729)	(24,540)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(3,559)	2,504
Total	$ (87,267)	$ 84,789

Interest Rate Hedging

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

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

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

At the inception of the interest rate swap agreement, a portion of the interest rate swap was to convert $129.0 million of our 7.875% senior notes from fixed rate debt to variable rate debt. Under SFAS 133, a hedge of interest rate risk in a recognized fixed rate liability can be designated as a fair value hedge. The mark-to-market value of the swap is therefore recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease in the carrying value of the debt. During 2002, $107.9 million face value of the 7.875% senior notes was purchased and subsequently retired. In connection with the repurchase of the 7.875% senior notes, interest rate swap hedging gains of $1.7 million were recognized and reduced the loss on repurchases of debt.

In July 2002, we closed the above interest rate swap for a gain of $7.5 million. As of December 31, 2002, the remaining balance to be amortized as a reduction to interest expense was $2.6 million. During 2002, $3.2 million was recognized as a reduction to interest expense.

In June 2002, we entered into an additional interest rate swap. The terms of this swap agreement are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
July 2002—July 2004	$100,000,000	4.000%	U.S. six-month LIBOR in arrears

In July 2002, we closed this interest rate swap for a gain of $1.1 million. As of December 31, 2002, the remaining balance to be amortized as a reduction to interest expenses was $0.9 million. During 2002, $0.2 million was recognized as a reduction to interest expense.

In April 2002, we entered into a swaption agreement in order to monetize the embedded call option in the remaining $142.7 million of our 8.5% senior notes. We received approximately $7.8 million from the counterparty at the time we entered into this agreement. The terms of the swaption are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
March 2004—March 2012	$142,665,000	8.500%	U.S. six-month LIBOR plus 75 basis points

Under the terms of the swaption agreement, the counterparty will have the option to initiate an interest rate swap on March 11, 2004 pursuant to the terms shown above. If the counterparty chooses to initiate the interest rate swap, the payments under the swap will coincide with the semi-annual interest payments on our 8.5% senior notes which are paid on September 15 and March 15 of each year. On each payment date, if the fixed rate exceeds the floating rate, we will pay the counterparty and if the floating rate exceeds the fixed rate, the counterparty will pay us accordingly. If the counterparty does not choose to initiate the interest rate swap, the swaption agreement will expire and no future obligations will exist for either party.

Under SFAS 133, a fair value hedge relationship exists between the embedded call option in the 8.5% senior notes and the swaption agreement. Accordingly, the mark-to-market value of the swaption is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease to the debt's carrying value. Any change in the fair value of the swaption resulting from ineffectiveness is recorded currently in the consolidated statements of operations as risk management income (loss).

We have recorded a decrease in the carrying value of the debt of $18.8 million during 2002 related to the swaption as of December 31, 2002. Of this amount, $22.3 million represents a decline in the fair value of the swaption, offset by a loss of $3.5 million from estimated ineffectiveness of the swaption as determined under SFAS 133. See Note 5 of the notes to consolidated financial statements in Item 8 of this report for the adjustments made to the carrying value of the debt at December 31, 2002. Results of the interest rate swap, if initiated, will be reflected as adjustments to interest expense in the corresponding months covered by the swaption agreement.

Risk management income (loss) related to our fair value hedges is comprised of the following:

	2002
	($ in thousands)
Risk management income (loss):	
Change in fair value of derivatives not qualifying for fair value hedge accounting	$ 4,593
Reclassification of gain on settled contracts to interest expense	(1,844)
Ineffective portion of derivatives qualifying for fair value hedge accounting	(3,500)
Total	$ (751)

Disclosures About Effects of Transactions with Related Parties

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. As of December 31, 2002, we had accrued accounts receivable from our CEO and COO of $1.0 million and $1.0 million, respectively, representing their December 2002 joint interest billings which were billed on January 15, 2003 and paid on January 16, 2003. Under their employment agreements, the CEO and COO are permitted to participate in all, or none, of the wells spudded by or on behalf of Chesapeake during each calendar quarter, but they are not allowed to only participate 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 2002, 2001 and 2000, we paid legal fees of $600,000, $391,000, and $439,000, respectively, for legal services provided by a law firm of which a director is a member.

Recently Issued Accounting Standards

In June 2001, the Financial Accounting Standards Board, or FASB, issued Statement of Financial Accounting Standards or SFAS Nos. 141 and 142. SFAS 141, *Business Combinations*, requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. SFAS 142, *Goodwill and Other Intangible Assets*, changes the accounting for goodwill from an amortization method to an impairment-only approach and was effective in January 2002. We have adopted these new standards, which have not had a significant effect on our results of operations or our financial position.

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS 143 is effective for fiscal years beginning after June 15, 2002 and establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-term assets (mainly plugging and abandonment costs for depleted wells) in the period in which the liability is incurred (at the time the wells are drilled). Accordingly, we adopted this standard in the first quarter of 2003. We expect the effect on our financial condition and results of operations at adoption will include an increase in liabilities of approximately $39 million and a cumulative effect for the change in accounting principle as a charge against earnings of approximately $10 million (net of income taxes). Subsequent to adoption, we do not expect this standard to have a material impact on our financial position or results of operations.

In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS 144 was effective January 1, 2002. This statement supersedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of*, and amends Accounting Principles Board Opinion, or APB, No. 30 for the accounting and reporting of discontinued operations, as it relates to long-lived assets. Our adoption of SFAS 144 did not affect our financial position or results of operations.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. SFAS 145 is effective for fiscal years beginning after May 15, 2002. We have adopted this standard early and it did not have a significant effect on our results of operations or our financial position.

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 do not expect the adoption of this standard to have any impact on our financial position or results of operations.

On December 31, 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation—Transition and Disclosure—An Amendment of SFAS 123.* The standard provides additional transition guidance for companies that elect to voluntarily adopt the accounting provisions of SFAS 123, *Accounting for Stock-Based Compensation*. SFAS 148 does not change the provisions of SFAS 123 that permit entities to continue to apply the intrinsic value method of APB 25, *Accounting for Stock Issued to Employees*. As we continue to follow APB 25, our accounting for stock-based compensation will not change as a result of SFAS 148. SFAS 148 does require certain new disclosures in both annual and interim financial statements. The required annual disclosures are effective immediately and have been included in Note 1 of our consolidated financial statements included in Item 8. The new interim disclosure provisions will be effective in the first quarter of 2003.

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.

On January 17, 2003, the FASB issued FIN 46, *Consolidation of Variable Interest Entities, An Interpretation of ARB 51*. The primary objectives of FIN 46 are to provide guidance on how to identify entities for which control is achieved through means other than through voting rights (variable interest entities or VIEs) and how to determine when and which business enterprise should consolidate the VIE. This new model for consolidation applies to an entity in which either (1) the equity investors do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties. We do not expect the adoption of this standard to have any impact on our financial position or results of operations.

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, 2002, our derivative instruments were comprised of swaps, cap-swaps, and basis protection swaps. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, 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, we receive a fixed price for the hedged commodity and pay a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure.
- Basis protection swaps are arrangements that guarantee a price differential of oil and 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.

From time to time, we close certain swap and cap-swap transactions designed to hedge a portion of our oil and natural gas production by entering into a counter-swap instrument. Under the counter-swap we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. To the extent the counter-swap, which does not qualify for hedge accounting under SFAS 133, is designed to lock the value of an existing SFAS 133 cash flow hedge, the net value of the swap and the counter-swap is frozen and shown as a derivative receivable or payable in the consolidated balance sheets. At the same time, the original swap is designated as a non-qualifying cash flow hedge under SFAS 133. The net receivable or payable is frozen until the related month of production and is then recognized as an increase or decrease to revenues. Changes in fair value occurring after the original swap has been designated as a non-qualifying cash flow hedge under SFAS 133 are included in results of operations. To the extent the counter-swap is designed to lock the value of a non-qualifying cash flow hedge under SFAS 133, the value of the counter-swap is shown as a derivative asset or liability in the consolidated balance sheet and referred to below as a fixed-price counter-swap. Any changes in the fair value of the counter-swap are included in results of operations.

Pursuant to SFAS 133, our cap-swaps, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. Therefore, changes in the fair value of these instruments that occur prior to their maturity, together with any changes in fair value of cash flow hedges resulting from ineffectiveness, are reported in the consolidated statements of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive SFAS 133 cash flow hedge accounting treatment. All amounts initially recorded in this caption related to commodity derivatives are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

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As of December 31, 2002, 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 2002:

	Volume	Average Strike Price	Weighted-Average Put Strike Price	Weighted-Average Differential to Mid-Continent Points	SFAS 133 Hedge	Fair Value at December 31, 2002 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
2003	57,150,000	4.31	—	—	Yes	(21,523)
Cap-Swaps:						
2003	51,100,000	3.60	2.60	—	No	(50,732)
Basis Protection Swaps:						
2003	91,250,000	—	—	(0.15)	No	5,562
2004	91,500,000	—	—	(0.15)	No	1,925
2005	98,550,000	—	—	(0.16)	No	476
2006	36,500,000	—	—	(0.16)	No	120
2007	45,625,000	—	—	(0.16)	No	96
2008	45,750,000	—	—	(0.16)	No	34
2009	36,500,000	—	—	(0.16)	No	14
Counter-Swaps:						
2003	45,700,000	3.74	—	—	No	37,048
Locked-Swaps:						
2003	—	—	—	—	No	16,498
Total Gas						(10,482)
Oil (bbls):						
Swaps:						
2003	360,000	25.10	—	—	Yes	(1,799)
Cap-Swaps:						
2003	3,015,000	28.10	—	—	No	(2,252)
Total Oil						(4,051)
Total Gas and Oil						$ (14,533)

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, 2002.

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

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

Risk management income (loss) related to our oil and gas derivatives is comprised of the following:

	December 31,	
	2002	2001
	($ in thousands)	
Risk management income (loss):		
Change in fair value of derivatives note qualifying for hedge accounting	$ (23,979)	$ 106,825
Reclassification of gain on settled contracts	(59,729)	(24,540)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(3,559)	2,504
Total	$ (87,267)	$ 84,789

The change in the fair value of our derivative instruments since January 1, 2002 resulted from an increase in market prices for natural gas and crude oil. 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.

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

Interest Rate Hedging

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

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

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

At the inception of the interest rate swap agreement, a portion of the interest rate swap was entered into to convert $129.0 million of our 7.875% senior notes from fixed rate debt to variable rate debt. Under SFAS 133, a hedge of interest rate risk in a recognized fixed rate liability can be designated as a fair value hedge. The mark-to-market value of the swap is therefore recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease in the carrying value of the debt. During 2002, $107.9 million face value of the 7.875% senior notes was purchased and subsequently retired. In connection with the repurchase of the 7.875% senior notes, interest rate swap hedging gains of $1.7 million were recognized in 2002, and reduce the loss on repurchases of debt.

In July 2002, we closed the above interest rate swap for a gain of $7.5 million. As of December 31, 2002, the remaining balance to be amortized as a reduction to interest expense was $2.6 million. During 2002, $3.2 million was recognized as a reduction to interest expense.

In June 2002, we entered into an additional interest rate swap. The terms of this swap agreement are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
July 2002—July 2004	$100,000,000	4.000%	U.S. six-month LIBOR in arrears

In July 2002, we closed this interest rate swap for a gain of $1.1 million. As of December 31, 2002, the remaining balance to amortize as a reduction to interest expense was $0.9 million. During 2002, $0.2 million was recognized as a reduction to interest expense.

In April 2002, we entered into a swaption agreement in order to monetize the embedded call option in the remaining $142.7 million of our 8.5% senior notes. We received $7.8 million from the counterparty at the time we entered into this agreement. The terms of the swaption are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
March 2004—March 2012	$142,665,000	8.500%	U.S. six-month LIBOR plus 75 basis points

Under the terms of the swaption agreement, the counterparty will have the option to initiate an interest rate swap on March 11, 2004 pursuant to the terms shown above. If the counterparty chooses to initiate the interest rate swap, the payments under the swap will coincide with the semi-annual interest payments on our 8.5% senior notes which are paid on September 15 and March 15 of each year. On each payment date, if the fixed rate exceeds the floating rate, we will pay the counterparty and if the floating rate exceeds the fixed rate, the counterparty will pay us accordingly. If the counterparty does not choose to initiate the interest rate swap, the swaption agreement will expire and no future obligations will exist for either party.

According to SFAS 133, a fair value hedge relationship exists between the embedded call option in the 8.5% senior notes and our swaption agreement. Accordingly, the mark-to-market value of the swaption is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease to the debt’s carrying value. Any change in the fair value of the swaption resulting from ineffectiveness is recorded currently in the consolidated statements of operations as risk management income (loss).

We have recorded a decrease in the carrying value of the debt of $18.8 million during 2002 related to the swaption as of December 31, 2002. Of this amount, $22.3 million represents a decline in the fair value of the swaption, offset by a loss of $3.5 million from estimated ineffectiveness of the swaption as determined under SFAS 133. See Note 5 of the notes to consolidated financial statements in Item 8 of this report for the adjustments made to the carrying value of the debt at December 31, 2002. Results of the interest rate swap, if initiated, will be reflected as adjustments to interest expense in the corresponding months covered by the swaption agreement.

Risk management income (loss) related to our fair value hedges is comprised of the following ($ in thousands):

	2002
	($ in thousands)
Risk management income (loss):	
Change in fair value of derivatives not qualifying for fair value hedge accounting	$ 4,593
Reclassification of gain on settled contracts to interest expense	(1,844)
Ineffective portion of derivatives qualifying for fair value hedge accounting	(3,500)
Total	$ (751)

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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.

	December 31, 2002							
	Years of Maturity							
	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value
	($ in millions)							
Liabilities:								
Long-term debt, including current portion—fixed rate	$ —	$ 42.1	$ —	$ —	$ —	$ 1,642.7	$ 1,684.8(1)	$ 1,744.7
Average interest rate	—	7.9%	—	—	—	8.3%	8.3%	8.3%

(1) This amount does not include the discount included in long-term debt of $15.5 million, the effect of interest rate swaps of $0.7 million and the effect of the swaption of ($18.8) 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.

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ITEM 8. *Financial Statements and Supplementary Data*

IN DEX TO FINANCIAL STATEMENTS

CHESAPEAKE ENERGY CORPORATION

REPORT OF INDEPENDENT ACCOUNTANTS

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, 2001 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, 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 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”*.

PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
February 24, 2003

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2002	December 31, 2001
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 247,637	$ 117,594
Restricted cash	82	7,366
Accounts receivable:		
Oil and gas sales	109,246	51,496
Joint interest, net of allowances of $1,433,000 and $947,000, respectively	22,760	17,364
Short-term derivatives	16,498	34,543
Related parties	2,155	9,896
Other	13,471	14,951
Deferred income tax asset	8,109	—
Short-term derivative instruments	—	97,544
Inventory and other	15,359	10,629
Total Current Assets	435,317	361,383
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	4,334,833	3,546,163
Unevaluated properties	72,506	66,205
Less: accumulated depreciation, depletion and amortization	(2,123,773)	(1,902,587)
	2,283,566	1,709,781
Other property and equipment	154,092	115,694
Less: accumulated depreciation and amortization	(47,774)	(39,894)
Total Property and Equipment	2,389,884	1,785,581
OTHER ASSETS:		
Long-term derivatives receivable	—	18,852
Deferred income tax asset	2,071	67,781
Long-term derivative instruments	2,666	6,370
Long-term investments	9,075	29,849
Other assets	36,595	16,952
Total Other Assets	50,407	139,804
TOTAL ASSETS	$ 2,875,608	$ 2,286,768
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Notes payable and current maturities of long-term debt	$ —	$ 602
Accounts payable	86,001	79,945
Accrued interest	35,025	26,316
Short-term derivative instruments	33,697	—
Other accrued liabilities	56,465	36,998
Revenues and royalties due others	54,364	29,520
Total Current Liabilities	265,552	173,381
LONG-TERM DEBT, NET	1,651,198	1,329,453
REVENUES AND ROYALTIES DUE OTHERS	13,797	12,696
LONG-TERM DERIVATIVE INSTRUMENTS	30,174	—
OTHER LIABILITIES	7,012	3,831
CONTINGENCIES AND COMMITMENTS (Note 4)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, $.01 par value, 10,000,000 shares authorized, 6.75% cumulative convertible preferred stock; 3,000,000 shares authorized, 2,998,000 and 3,000,000 issued and outstanding at December 31, 2002 and 2001, respectively, entitled in liquidation to $149,900,000 and $150,000,000	149,900	150,000
Common Stock, $.01 par value, 350,000,000 shares authorized, 194,936,912 and 169,534,991 shares issued at December 31, 2002 and 2001, respectively	1,949	1,696
Paid-in capital	1,205,554	1,035,156
Accumulated deficit	(426,085)	(442,974)
Accumulated other comprehensive income (loss), net of tax of $2,307,000 and $(29,000,000), respectively	(3,461)	43,511
Less: treasury stock, at cost; 4,792,529 common shares at December 31, 2002 and 2001	(19,982)	(19,982)
Total Stockholders' Equity	907,875	767,407
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 2,875,608	$ 2,286,768

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,		
	2002	2001	2000
	(in thousands, except per share data)		
REVENUES:			
Oil and gas sales	$ 655,454	$ 735,529	$ 470,170
Risk management income (loss)	(88,018)	84,789	—
Oil and gas marketing sales	170,315	148,733	157,782
Total Revenues	737,751	969,051	627,952
OPERATING COSTS:			
Production expenses	98,191	75,374	50,085
Production taxes	30,101	33,010	24,840
General and administrative	17,618	14,449	13,177
Oil and gas marketing expenses	165,736	144,373	152,309
Oil and gas depreciation, depletion and amortization	221,189	172,902	101,291
Depreciation and amortization of other assets	14,009	8,663	7,481
Total Operating Costs	546,844	448,771	349,183
INCOME FROM OPERATIONS	190,907	520,280	278,769
OTHER INCOME (EXPENSE):			
Interest and other income	7,340	2,877	3,649
Interest expense	(111,280)	(98,321)	(86,256)
Loss on investment in Seven Seas	(17,201)	—	—
Loss on repurchases of debt	(2,626)	—	—
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)	(123,767)	(81,915)	(82,607)
INCOME BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	67,140	438,365	196,162
PROVISION (BENEFIT) FOR INCOME TAXES	26,854	174,959	(259,408)
INCOME BEFORE EXTRAORDINARY ITEM	40,286	263,406	455,570
EXTRAORDINARY ITEM:			
Loss on early extinguishment of debt, net of applicable income tax of $30,667,000	—	(46,000)	—
NET INCOME	40,286	217,406	455,570
PREFERRED STOCK DIVIDENDS	(10,117)	(2,050)	(8,484)
GAIN ON REDEMPTION OF PREFERRED STOCK	—	—	6,574
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 30,169	$ 215,356	$ 453,660
EARNINGS PER COMMON SHARE:			
BASIC:			
Income before extraordinary item	$ 0.18	$ 1.61	$ 3.52
Extraordinary item	—	(0.28)	—
Net income	$ 0.18	$ 1.33	$ 3.52
ASSUMING DILUTION:			
Income before extraordinary item	$ 0.17	$ 1.51	$ 3.01
Extraordinary item	—	(0.26)	—
Net income	$ 0.17	$ 1.25	$ 3.01
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING:			
Basic	166,910	162,362	128,993
Assuming dilution	172,714	173,981	151,564

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, 2002	2001	2000
	($ in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME	$ 40,286	$ 217,406	$ 455,570
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	230,236	177,543	105,103
Risk management income	88,018	(84,789)	—
Extraordinary loss on early extinguishment of debt	—	46,000	—
Deferred income taxes	28,676	169,498	(259,408)
Impairment of investments	—	10,079	250
Loss on investment in Seven Seas	17,201	—	—
Accretion of Seven Seas note discount	(956)	—	—
Gain on sale of Canadian subsidiary	—	(27,000)	—
Write-off of credit facility costs	—	3,392	—
Loss on repurchases of debt	2,626	—	—
Amortization of loan costs	4,962	4,022	3,669
Amortization of bond discount	1,079	1,062	84
Bad debt expense	315	69	256
Gain (loss) on sale of fixed assets and other	29	68	8
Equity in losses of equity investees	—	1,312	131
Other	45	(99)	141
Cash provided by operating activities before changes in assets and liabilities	412,517	518,563	305,804
CHANGES IN ASSETS AND LIABILITIES:			
(Increase) decrease in accounts receivable	(44,966)	34,265	(66,706)
(Increase) decrease in inventory and other assets	11,330	929	4,299
Increase (decrease) in accounts payable, accrued liabilities and other	23,223	2,454	64,961
Increase (decrease) in current and non-current revenues and royalties due others	30,427	(2,474)	6,282
Changes in assets and liabilities	20,014	35,174	8,836
Cash provided by operating activities	432,531	553,737	314,640
CASH FLOWS FROM INVESTING ACTIVITIES:			
Exploration and development of oil and gas properties	(400,180)	(420,969)	(188,778)
Acquisitions of oil and gas companies, proved properties and unproved properties, net of cash acquired	(331,651)	(316,743)	(78,910)
Deposit for ONEOK acquisition	(15,000)	—	—
Sale of Canadian subsidiary	—	142,906	—
Divestitures of oil and gas properties	839	1,432	1,529
Sale of non-oil and gas assets	5,774	3,204	1,069
Additions to buildings and other fixed assets	(33,559)	(24,853)	(13,427)
Additions to drilling rig equipment	(3,551)	(14,145)	—
Additions to long-term investments	(2,408)	(40,239)	(9,937)
Investment in Gothic Energy Corporation	—	—	(36,693)
Other	(9)	(698)	(82)
Cash used in investing activities	(779,745)	(670,105)	(325,229)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	252,500	433,500	244,000
Payments on long-term borrowings	(252,500)	(458,500)	(262,500)
Additions to deferred charges	(421)	—	—
Cash received from issuance of senior notes	446,638	1,036,342	—
Cash paid for issuance costs of senior notes	(7,211)	(8,067)	—
Cash paid for financing costs of credit facilities	(2,902)	(6,611)	(4,807)
Cash paid to purchase senior notes	(107,863)	(830,382)	—
Cash paid for redemption premium of senior notes	(3,734)	(75,639)	—
Cash paid for common stock dividend	(4,987)	—	—
Cash paid for preferred stock dividend	(10,177)	(1,092)	(4,645)
Proceeds from issuance of preferred stock, net of costs	—	145,086	—
Proceeds from issuance of common stock, net of offering costs	164,104	—	—
Purchase of treasury stock and preferred stock	—	(10)	—
Cash paid in connection with issuance of common stock for preferred stock	—	—	(8,269)
Cash received (paid) in settlements of make-whole provisions	—	(3,336)	7,083
Cash received from exercise of stock options	3,810	3,216	1,398
Cash provided by (used in) financing activities	477,257	234,507	(27,740)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	—	(545)	(329)
Net increase (decrease) in cash and cash equivalents	130,043	117,594	(38,658)
Cash and cash equivalents, beginning of period	117,594	—	38,658
Cash and cash equivalents, end of period	$ 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,		
	2002	2001	2000
	($ in thousands)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$ 105,671	$ 97,832	$ 85,401
Income taxes, net of refunds received	$ (738)	$ 5,461	$ —
DETAILS OF ACQUISITION OF GOTHIC ENERGY CORPORATION:			
Fair value of properties acquired	$ —	$ 371,371	$ —
Fair value of notes acquired	$ —	$ —	$ 115,545
Cash consideration	$ —	$ —	$ (28,715)
Stock issued (13,553,276 shares and 3,989,813 shares)	$ —	$ (28,000)	$ (86,830)
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 2002, holders of our 6.75% cumulative 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.

During 2000, Chesapeake engaged in unsolicited transactions in which a total of 43.4 million shares of Chesapeake common stock, plus a cash payment of $8.3 million, were exchanged for 3,972,363 shares of Chesapeake 7% preferred stock.

During 2000, Chesapeake Energy Marketing, Inc. purchased 99.8% of Gothic Energy Corporation's $104 million 14.125% Series B senior secured discount notes for total consideration of $80.8 million, comprised of $17.2 million in cash and $63.6 million of Chesapeake common stock (8,875,775 shares valued at $7.16 per share), as adjusted for make-whole provisions. Through the make-whole provisions, Chesapeake Energy Marketing, Inc. received $6.1 million in cash and $7.2 million of Chesapeake common stock (982,562 shares).

In 2000, Chesapeake purchased $31.6 million of the $235 million of 11.125% senior secured notes issued by Gothic Production Corporation for total consideration of $34.8 million, comprised of $11.5 million in cash and $23.3 million of Chesapeake common stock (3,694,939 shares valued at $6.30 per share), as adjusted for make-whole provisions. Through the make-whole provisions, Chesapeake received $1.0 million in cash.

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,		
	2002	2001	2000
	($ in thousands)		
PREFERRED STOCK:			
Balance, beginning of period	$ 150,000	$ 31,202	$ 229,820
Exchange of common stock and cash for 3,972,363 shares of preferred stock	—	—	(198,618)
Exchange of common stock for 624,037 shares of preferred stock	—	(31,202)	—
Exchange of common stock for 2,000 shares of preferred stock	(100)	—	—
Issuance of preferred stock	—	150,000	—
Balance, end of period	149,900	150,000	31,202
COMMON STOCK:			
Balance, beginning of period	1,696	1,578	1,059
Exercise of stock options and warrants	23	21	20
Issuance of 23,000,000 of common stock	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 36,366,915 shares of common stock for preferred stock	—	—	363
Issuance of 13,553,276 shares of common stock to acquire Gothic notes	—	—	136
Exchange of 4,487,410 shares of common stock for preferred stock	—	45	—
Other	—	1	—
Balance, end of period	1,949	1,696	1,578
PAID-IN CAPITAL:			
Balance, beginning of period	1,035,156	963,584	682,905
Exercise of stock options and warrants	3,787	3,188	1,377
Issuance of common stock	172,270	—	—
Issuance of common stock to acquire Gothic notes	—	—	93,885
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 and other	(8,506)	(4,891)	—
Exchange of 12,987 shares of common stock for preferred stock	100	—	—
Exchange of 36,366,915 shares of common stock for preferred stock	—	—	187,069
Exchange of 4,487,410 shares of common stock for preferred stock	—	31,157	—
Exchange of 7,050,000 shares of treasury stock for preferred stock	—	—	(5,640)
Make-whole payments on common stock issued to RAM Energy, Inc. shareholders	—	(3,336)	—
Compensation related to stock options	356	800	238
Tax benefit from exercise of stock options	2,391	5,384	3,750
Balance, end of period	1,205,554	1,035,156	963,584
ACCUMULATED DEFICIT:			
Balance, beginning of period	(442,974)	(659,286)	(1,093,929)
Net income	40,286	217,406	455,570
Dividends on common stock	(10,690)	—	—
Dividends on preferred stock	(12,707)	(1,094)	(4,645)
Fair value of common stock exchanged in excess of book value of preferred stock	—	—	(8,013)
Cash paid in connection with issuance of common stock for preferred stock	—	—	(8,269)
Balance, end of period	(426,085)	(442,974)	(659,286)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	43,511	(3,901)	196
Foreign currency translation adjustments	—	(3,551)	(4,097)
Transfer of translation adjustments related to sale of Canadian subsidiary	—	7,452	—
Gain/(loss) on hedging activity	(46,972)	43,511	—
Balance, end of period	(3,461)	43,511	(3,901)
TREASURY STOCK—COMMON:			
Balance, beginning of period	(19,982)	(19,945)	(37,595)
Exercised options	—	(37)	—
Exchange of 7,050,000 shares of treasury stock for preferred stock	—	—	24,841
Receipt of 982,562 shares of common stock from previous Gothic note holders in settlement of make-whole provision	—	—	(7,191)
Balance, end of period	(19,982)	(19,982)	(19,945)
TOTAL STOCKHOLDERS' EQUITY	$ 907,875	$ 767,407	$ 313,232

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,		
	2002	2001	2000
		($ in thousands)	
Net income	$ 40,286	$ 217,406	$ 455,570
Other comprehensive income (loss), net of income tax:			
Foreign currency translation adjustments	—	(3,551)	(4,097)
Transfer of translation adjustments related to sale of Canadian subsidiary	—	7,452	—
Cumulative effect of accounting change for financial derivatives	—	(53,573)	—
Change in fair value of derivative instruments	(27,041)	147,210	—
Reclassification of gain on settled contracts	(22,066)	(48,623)	—
Ineffective portion of derivatives qualifying for hedge accounting	2,135	(1,503)	—
Comprehensive income (loss)	$ (6,686)	$ 264,818	$ 451,473

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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.

Inventory

Inventory, which is included in other 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 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, 2002, approximately 73% of our present value (discounted at 10%) of estimated future net revenues of proved reserves was evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers evaluate all properties quarterly. The average composite rates used for depreciation, depletion and amortization were $1.22 (U.S.) per equivalent mcf in 2002, $1.07 ($1.08 in U.S. and $0.90 in Canada) per equivalent mcf in 2001, and $0.75 ($0.76 in U.S. and $0.71 in Canada) per equivalent mcf in 2000.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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. 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. 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.

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. Buildings are depreciated over 31.5 years, drilling rigs are depreciated over 12 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from three to seven years.

Capitalized Interest

During 2002, 2001 and 2000, interest of approximately $5.0 million, $4.7 million and $2.4 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.

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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, 2002 and 2001, outstanding warrants to purchase 0.6 million and 1.1 million shares of common stock at a weighted average exercise price of $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, 2002, 2001 and 2000, outstanding options to purchase 0.6 million, 0.3 million, and 1.1 million shares of common stock at a weighted average exercise price of $11.93, $15.54, and $8.73, 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, 2002, 2001 and 2000 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
		(in thousands, except per share data)	
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% preferred stock	—	2,989	
Common shares assumed issued prior to conversion for 7% 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
For the Year Ended December 31, 2000:			
Basic EPS			
Income available to common stockholders	$ 453,660	128,993	$ 3.52
Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of preferred shares exchanged during the period:			
Common shares assumed issued	—	11,440	
Preferred stock dividends	8,484	—	
Gain on redemption of preferred stock	(6,574)	—	
Assumed conversion of 624,037 shares of 7% preferred stock at beginning of period	—	4,489	
Employee stock options	—	6,642	
Diluted EPS			
Income available to common shareholders	$ 455,570	151,564	$ 3.01

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).

On November 13, 2001, we issued 3.0 million shares of 6.75% 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 shares of the preferred stock and underlying common stock for resale by the holders.

During the year ended December 31, 2000, Chesapeake engaged in a number of unsolicited stock transactions with institutional investors. A total of 43.4 million shares of common stock, plus a cash payment of $8.3 million, were exchanged for 3,972,363 shares of 7% preferred stock. These transactions reduced (i) the number of preferred shares from 4.6 million to 0.6 million, (ii) the liquidation value of the preferred stock from $229.8 million to $31.2 million, and (iii) dividends in arrears by $22.9 million. A gain on redemption of all preferred shares exchanged during 2000 of $6.6 million is reflected in net income available to common shareholders in determining basic earnings per share. All preferred shares acquired in these transactions were canceled and retired and restored to the status of authorized but unissued shares of undesignated preferred stock. The gain represented the excess of (i) the liquidation value of the preferred shares that were retired plus dividends in arrears which had reduced prior EPS over (ii) the market value of the common stock issued and cash paid in exchange for the preferred shares.

Gas Imbalances — Revenue Recognition

Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. 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. A liability is recognized only to the extent that we have an imbalance in excess of the remaining gas reserves on the underlying properties. The net gas imbalance liability at December 31, 2002 and 2001 was not significant.

Hedging

Chesapeake periodically uses commodity price and financial risk management instruments to hedge our exposure to price fluctuations in oil and natural gas transactions and interest rates. Recognized gains and losses on hedge contracts are reported as a component of the related transaction. Results of oil and gas hedging transactions are reflected in oil and gas sales to the extent related to our oil and gas production, 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 cash flow hedges that occur prior to maturity are initially reported in the statement of operations as risk management income (loss). All amounts recorded in this caption are ultimately reversed within the same caption and included in oil and gas sales over the respective contract terms.

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. Special accounting for qualifying hedges allows a derivative’s gains and losses to offset related results of the hedged item in the consolidated statement of operations. 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. For derivative instruments designated as fair value hedges, changes in fair value, to the extent the hedge is effective, are recognized as an increase or decrease to the value of the hedged item until the hedged item is recognized in earnings. 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. Any change in fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in earnings. Changes in fair value of contracts that do not meet the SFAS 133 definition of a cash flow or fair value hedge are also recognized in earnings through risk management income.

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.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and amendments to our revolving bank credit facility. The remaining unamortized debt issue costs at December 31, 2002 and 2001 totaled $21.5 million and $16.6 million, respectively, and are being amortized over the life of the senior notes or revolving credit facility.

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 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 stock option. Compensation expense of $0.4 million and $0.8 million was recognized in 2002 and 2001, respectively as a result of modifications that were made during the years ended December 31, 2001 and 2000. No compensation expense has been recognized for newly issued stock options in 2002, 2001 or 2000 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 2002, 2001 and 2000, respectively: interest rates (zero-coupon U.S. government issues with a remaining life equal to the expected term of the options) of

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

between 2.78% and 4.90%, 4.67%, and 6.32%, dividend yields of between 0% and 1.85%, 0.0%, and 0.0%, and volatility factors of the expected market price of our common stock of between 0.49 and 0.54, 0.58, and 0.73. We used a weighted-average expected life of the options of five years for each of 2002, 2001 and 2000.

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,		
	2002	2001	2000
	($ in thousands, except per share amounts)		
Net Income			
As reported(1)	$ 40,286	$ 217,406	$ 455,570
Less compensation expense, net of tax	8,644	9,063	6,423
Pro forma	$ 31,642	$ 208,343	$ 449,147
Basic Earnings per common share:			
As reported	$ 0.18	$ 1.33	$ 3.52
Less compensation expense, net of tax	0.05	0.06	0.05
Pro forma	$ 0.13	$ 1.27	$ 3.47
Diluted Earnings per common share:			
As reported	$ 0.17	$ 1.25	$ 3.01
Less compensation expense, net of tax	0.05	0.05	0.05
Pro forma	$ 0.12	$ 1.20	$ 2.96

(1) Includes compensation expenses related to FIN 44 of $0.4 million and $0.8 million in 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. Because our stock options vest over four years and additional awards are typically made each year, the above pro forma disclosures are not likely 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 2001 and 2000 to conform to the presentation used for the 2002 consolidated financial statements.

2. Senior Notes

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 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 November 5, 2001, Chesapeake issued $250.0 million principal amount of 8.375% senior notes due 2008, which were exchanged on January 23, 2002 for substantially identical notes registered under the Securities Act of 1933.

On April 6, 2001, we issued $800.0 million principal amount of 8.125% senior notes due 2011, substantially all of which were exchanged on July 12, 2001 for substantially identical notes registered under the Securities Act of 1933. During April 2001, we used a portion of the offering proceeds to purchase $140.7 million principal amount of our 9.625% senior notes and $3.0 million principal amount of the 11.125% senior secured notes of Gothic Production Corporation, a Chesapeake subsidiary. On May 7, 2001, we redeemed all $120.0 million principal amount of our 9.125% senior notes, the remaining $359.3 million principal amount of our 9.625% senior notes and the remaining $199.3 million principal amount of Gothic Production Corporation’s 11.125% senior secured 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. The costs associated with the early extinguishment of debt are reflected as a $46.0 million after-tax extraordinary loss in 2001.

On January 16, 2001, we acquired Gothic Energy Corporation and assumed its note obligations. At that date, there was outstanding $203.3 million principal amount of 11.125% senior secured notes due 2005 which had been issued by Gothic Production Corporation and guaranteed by Gothic Energy Corporation, its parent. In February 2001, we purchased $1.0 million principal amount of these notes tendered pursuant to a change-of-control offer at a purchase price of 101%. In April 2001, we purchased $3.0 million of these notes for total consideration of $3.5 million, including $0.1 million in interest and $0.4 million in premium. On May 7, 2001, we redeemed the remaining notes ($199.3 million principal amount) for total consideration of $222.5 million, including $0.4 million in interest and $22.8 million in redemption premium.

On April 22, 1998, we issued $500.0 million principal amount of 9.625% senior notes due 2005. In April 2001, we purchased $140.7 million of these notes for total consideration of $160.2 million, including a $13.6 million premium and interest of $5.9 million. On May 7, 2001, we redeemed the remaining notes, $359.3 million principal amount, for total consideration of $393.3 million, including $0.6 million of interest and $33.4 million of redemption premium.

On March 17, 1997, we issued $150.0 million principal amount of 7.875% senior notes due 2004. During 2002, Chesapeake purchased and subsequently retired $107.9 million of the 7.875% senior notes, for a total consideration of $112.9 million, including $1.3 million of accrued interest and $3.7 million of redemption premium.

Also 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 April 9, 1996, we issued $120.0 million principal amount of 9.125% senior notes due 2006. On May 7, 2001, we redeemed these notes for total consideration of $126.1 million, including $0.7 million in interest and $5.4 million of redemption premium.

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 Chesapeake Energy Marketing, Inc., a wholly owned subsidiary which is not a guarantor of the senior notes and was a non-guarantor subsidiary for all periods presented. All of our other wholly-owned subsidiaries were guarantor subsidiaries during all periods presented.

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

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	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:					
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 (DEFICIT)					
CURRENT LIABILITIES:					
Accounts payable	$ 82,083	$ 71,316	$ —	$ (67,398)	$ 86,001
Accrued interest	—	—	35,025	—	35,025
Accrued liabilities	46,231	1,960	8,326	(52)	56,465
Short-term derivative instruments	33,697	—	—	—	33,697
Revenues and royalties due others	33,776	—	—	20,588	54,364
Total Current Liabilities	195,787	73,276	43,351	(46,862)	265,552
LONG-TERM DEBT	—	—	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)	—
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	66	1	1,939	(57)	1,949
Other	327,444	30,187	905,936	(357,641)	905,926
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

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CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2001
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents, including restricted cash	$ (7,905)	$ 19,714	$ 113,151	$ —	$ 124,960
Accounts receivable	78,950	30,380	2,715	(18,338)	93,707
Short-term derivative receivable	34,543	—	—	—	34,543
Short-term derivative instruments	97,544	—	—	—	97,544
Inventory and other	10,208	421	—	—	10,629
Total Current Assets	213,340	50,515	115,866	(18,338)	361,383
PROPERTY AND EQUIPMENT:					
Oil and gas properties	3,546,163	—	—	—	3,546,163
Unevaluated leasehold	66,205	—	—	—	66,205
Other property and equipment	53,681	23,537	38,476	—	115,694
Less: accumulated depreciation, depletion and amortization	(1,920,613)	(18,668)	(3,200)	—	(1,942,481)
Net Property and Equipment	1,745,436	4,869	35,276	—	1,785,581
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	—	—	(21,054)	21,054	—
Long-term derivative receivable	18,852	—	—	—	18,852
Deferred income tax asset	(218,596)	(1,376)	287,753	—	67,781
Long-term derivative instruments	6,370	—	—	—	6,370
Long-term investments	—	—	29,849	—	29,849
Other assets	5,589	334	11,050	(21)	16,952
Total Other Assets	(187,785)	(1,042)	307,598	21,033	139,804
TOTAL ASSETS	$ 1,770,991	$ 54,342	$ 458,740	$ 2,695	$ 2,286,768
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 602	$ —	$ —	$ —	$ 602
Accounts payable	76,444	35,600	—	(32,099)	79,945
Accrued interest	—	—	26,316	—	26,316
Accrued liabilities	35,764	1,155	22	57	36,998
Revenues and royalties due others	15,759	—	—	13,761	29,520
Total Current Liabilities	128,569	36,755	26,338	(18,281)	173,381
LONG-TERM DEBT	—	—	1,329,453	—	1,329,453
REVENUES AND ROYALTIES DUE OTHERS	12,696	—	—	—	12,696
OTHER LIABILITIES	3,831	—	—	—	3,831
INTERCOMPANY PAYABLES	1,664,517	19	(1,664,458)	(78)	—
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	66	1	1,686	(57)	1,696
Other	(38,688)	17,567	765,721	21,111	765,711
Total Stockholders' Equity	(38,622)	17,568	767,407	21,054	767,407
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,770,991	$ 54,342	$ 458,740	$ 2,695	$ 2,286,768

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Year Ended December 31, 2002:					
REVENUES:					
Oil and gas sales	$ 655,454	$ —	$ —	$ —	$ 655,454
Risk management income (loss)	(87,267)	—	(751)	—	(88,018)
Oil and gas marketing sales	—	548,388	—	(378,073)	170,315
Total Revenues	568,187	548,388	(751)	(378,073)	737,751
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	(4,040)	—	190,907
OTHER INCOME (EXPENSE):					
Interest and other income	1,580	597	120,046	(114,883)	7,340
Interest expense	(111,943)	(10)	(114,210)	114,883	(111,280)
Loss on investment in Seven Seas	—	—	(17,201)	—	(17,201)
Loss on repurchases of debt	—	—	(2,626)	—	(2,626)
Equity in net earnings of subsidiaries	—	—	51,104	(51,104)	—
Total Other Income (Expense)	(110,363)	587	37,113	(51,104)	(123,767)
INCOME (LOSS) 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 (LOSS)	$ 50,257	$ 847	$ 40,286	$ (51,104)	$ 40,286

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Year Ended December 31, 2001:					
REVENUES:					
Oil and gas sales	$ 735,529	$ —	$ —	$ —	$ 735,529
Risk management income	84,789	—	—	—	84,789
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

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
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)
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)	—
	(109,240)	471	266,822	(239,968)	(81,915)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	411,556	3,440	263,337	(239,968)	438,365
INCOME TAX EXPENSE	165,481	1,376	8,102	—	174,959
INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	246,075	2,064	255,235	(239,968)	263,406
EXTRAORDINARY ITEM:					
Loss on early extinguishment of debt, net of applicable income tax	(8,171)	—	(37,829)	—	(46,000)
NET INCOME (LOSS)	$ 237,904	$ 2,064	$ 217,406	$ (239,968)	$ 217,406

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Year Ended December 31, 2000:					
REVENUES:					
Oil and gas sales	$ 469,823	$ 347	$ —	$ —	$ 470,170
Oil and gas marketing sales	—	361,023	—	(203,241)	157,782
Total Revenues	469,823	361,370	—	(203,241)	627,952
OPERATING COSTS:					
Production expenses	50,024	61	—	—	50,085
Production taxes	24,821	19	—	—	24,840
General and administrative	11,635	1,218	324	—	13,177
Oil and gas marketing expenses	—	355,550	—	(203,241)	152,309
Oil and gas depreciation, depletion and amortization	101,190	101	—	—	101,291
Depreciation and amortization of other assets	4,082	80	3,319	—	7,481
Total Operating Costs	191,752	357,029	3,643	(203,241)	349,183
INCOME (LOSS) FROM OPERATIONS	278,071	4,341	(3,643)	—	278,769
OTHER INCOME (EXPENSE):					
Interest and other income	2,736	883	87,910	(87,880)	3,649
Interest expense	(90,170)	(35)	(83,931)	87,880	(86,256)
Equity in net earnings of subsidiaries	—	—	190,234	(190,234)	—
	(87,434)	848	194,213	(190,234)	(82,607)
INCOME (LOSS) BEFORE INCOME TAXES	190,637	5,189	190,570	(190,234)	196,162
INCOME TAX EXPENSE	5,592	—	(265,000)	—	(259,408)
NET INCOME (LOSS)	$ 185,045	$ 5,189	$ 455,570	$ (190,234)	$ 455,570

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CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	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)
Deposit for ONEOK acquisition	(15,000)	—	—	—	(15,000)
Proceeds from sale of non-oil and gas assets	1,559	—	4,215	—	5,774
Additions to other property and equipment	(12,927)	(3,860)	(20,323)	—	(37,110)
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 issuance costs	—	—	446,638	—	446,638
Cash paid for issuance of senior notes	—	—	(7,211)	—	(7,211)
Proceeds from issuance of common stock, net of issuance costs	—	—	164,104	—	164,104
Additions to deferred charges	(2,902)	—	(421)	—	(3,323)
Cash paid to repurchase senior notes	—	—	(107,863)	—	(107,863)
Cash paid for redemption premium of senior notes	—	—	(3,734)	—	(3,734)
Cash dividends paid on preferred stock and common stock	—	—	(15,164)	—	(15,164)
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

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	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)
Proceeds from sale of non-oil and gas assets	3,204	—	—	—	3,204
Additions to other property and equipment	(26,212)	(292)	(12,494)	—	(38,998)
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	—	—	1,036,342	—	1,036,342
Cash paid for issuance of senior notes	—	—	(8,067)	—	(8,067)
Additions to deferred charges	(5,984)	—	(627)	—	(6,611)
Cash paid to redeem senior notes	—	—	(906,021)	—	(906,021)
Cash received from issuance of preferred stock, net of issuance costs	—	—	145,086	—	145,086
Cash paid for purchase of preferred stock, net of issuance costs	—	—	(10)	—	(10)
Cash paid on make whole provision	—	—	(3,336)	—	(3,336)
Cash dividends paid on preferred stock	—	—	(1,092)	—	(1,092)
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 CASH FLOWS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Year Ended December 31, 2000:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 320,002	$ (9,627)	$ 194,499	$ (190,234)	$ 314,640
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(267,674)	1,515	—	—	(266,159)
Proceeds from sale of non-oil and gas assets	782	16	271	—	1,069
Other investments	(8,019)	—	(2,000)	—	(10,019)
Investment in Gothic Energy Corporation	—	(33,076)	(3,617)	—	(36,693)
Other additions	(2,540)	(2,740)	(8,147)	—	(13,427)
Cash (used in) provided by investing activities	(277,451)	(34,285)	(13,493)	—	(325,229)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	244,000	—	—	—	244,000
Payments on long-term borrowings	(262,500)	—	—	—	(262,500)
Additions to deferred charges	(1,913)	—	(2,894)	—	(4,807)
Cash paid for redemption of preferred stock	—	—	(8,269)	—	(8,269)
Cash received on make whole provision	—	6,109	974	—	7,083
Cash dividends paid on preferred stock	—	—	(4,645)	—	(4,645)
Exercise of stock options	—	—	1,398	—	1,398
Intercompany advances, net	(34,521)	24,594	(180,307)	190,234	—
Cash provided by (used in) financing activities	(54,934)	30,703	(193,743)	190,234	(27,740)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(329)	—	—	—	(329)
Net increase (decrease) in cash and cash equivalents	(12,712)	(13,209)	(12,737)	—	(38,658)
Cash, beginning of period	(7,156)	20,409	25,405	—	38,658
Cash, end of period	$ (19,868)	$ 7,200	$ 12,668	$ —	$ —

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

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
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:					
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)
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)
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
For the Year Ended December 31, 2000:					
Net income	$ 185,045	$ 5,189	$ 455,570	$ (190,234)	$ 455,570
Other comprehensive income (loss)—net of income tax:					
Foreign currency translation adjustments	(4,097)	—	—	—	(4,097)
Equity in net other comprehensive income (loss) of subsidiaries	—	—	(4,097)	4,097	—
Comprehensive income	$ 180,948	$ 5,189	$ 451,473	$ (186,137)	$ 451,473

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

3. Notes Payable and Long-Term Debt

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

	December 31,	
	2002	2001
	($ in thousands)	
7.875% Senior Notes due 2004	$ 42,137	$ 150,000
8.5% Senior Notes due 2012	142,665	142,665
8.125% Senior Notes due 2011	800,000	800,000
8.375% Senior Notes due 2008	250,000	250,000
9.0% Senior Notes due 2012	300,000	—
7.75% Senior Notes due 2015	150,000	—
Note payable	—	602
Discount of senior notes	(15,482)	(13,212)
Discount for interest rate swap and swaption	(18,122)	—
Total notes payable and long-term debt	1,651,198	1,330,055
Less—current maturities	—	(602)
Notes payable and long-term debt, net of current maturities	$ 1,651,198	$ 1,329,453

We have a $250 million revolving bank credit facility (with a committed borrowing base of $250 million) which matures in June 2005. As of December 31, 2002, we had no outstanding borrowings under this facility and utilized $25.4 million of the facility for various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either the reference rate of Union Bank of California, N.A., or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to total facility usage. The unused portion of the facility is subject to an annual commitment fee of 0.50%. 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, create liens, and make acquisitions. The credit facility agreement requires us to maintain a current ratio (as defined) of at least 1 to 1 and a fixed charge coverage ratio (as defined) of at least 2.5 to 1. At December 31, 2002, our current ratio was 2.5 to 1 and our fixed charge coverage ratio was 2.9 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $5.0 million.

The aggregate scheduled maturities of notes payable and long-term debt for the five fiscal years ending December 31, 2007 and thereafter were as follows as of December 31, 2002 ($ in thousands):

2003	$ —
2004	42,137
2005	—
2006	—
2007	—
After 2007	1,642,665
	$ 1,684,802

4. Contingencies and Commitments

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

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

Chesapeake is currently involved in various other routine 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.

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 July 1, 2002. The term of each agreement is automatically extended for one additional year on each June 30 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 June 30, 2003. The employment agreements with the chief executive officer and chief operating officer provide that in the event of a change in control, under some circumstances, each is 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.

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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 is not aware of any potential material environmental issues or claims.

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

Chesapeake has entered into various operating leases for office space and equipment. Future minimum lease payments required as of December 31, 2002 related to these operating leases are as follows ($ in thousands):

2003	$	824
2004		705
2005		433
2006		166
2007		159
After 2007		517
Total	$	2,804

Rent expense, including short-term rentals, for the years ended December 31, 2002, 2001 and 2000 was $7.7 million, $6.4 million and $4.4 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,		
	2002	2001	2000
	($ in thousands)		
Current	$ (1,822)	$ 3,565	$ 1,800
Deferred:			
United States	28,676	167,658	(266,800)
Foreign	—	3,736	5,592
Total	$ 26,854	$ 174,959	$ (259,408)

The effective income tax expense (benefit) differed from the computed "expected" federal income tax expense (benefit) on earnings before income taxes and extraordinary items for the following reasons:

	Years Ended December 31,		
	2002	2001	2000
	($ in thousands)		
Computed "expected" federal income tax provision	$ 23,499	$ 153,428	$ 68,657
Foreign taxes in excess of U.S. statutory rates	—	391	302
Tax percentage depletion	(137)	(195)	(191)
Change in valuation allowance	—	2,441	(329,516)
State income taxes and other	3,492	18,894	1,340
	$ 26,854	$ 174,959	$ (259,408)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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, 2002	Years Ended December 31, 2001
	($ in thousands)	
Deferred tax liabilities:		
Acquisition, exploration and development costs and related depreciation, depletion and amortization	$ (265,837)(1)	$ (171,506)
Derivative assets and other	— (1)	(58,713)
Deferred tax liabilities	$ (265,837)	$ (230,219)
Deferred tax assets:		
Acquisition, exploration and development costs and related depreciation, depletion and amortization	$ —	$ —
Net operating loss carryforwards	256,547 (1)	295,612
Derivative liabilities and other	18,837 (1)	—
Percentage depletion carryforwards	3,063 (1)	2,212
Alternative minimum tax credits	11 (1)	2,617
Deferred tax assets	$ 278,458	$ 300,441
Net deferred tax asset (liability)	$ 12,621	$ 70,222
Less: Valuation allowance	(2,441)	(2,441)
Total deferred tax asset (liability)	$ 10,180	$ 67,781
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 8,109	$ —
Non-current deferred income tax asset	2,071	67,781
Non-current deferred income tax liability	—	—
	$ 10,180	$ 67,781

(1) Activity includes a net liability of $61.9 million related to acquisitions, a benefit of $31.3 million related to derivative instruments, a liability of $0.8 million related to AMT refunds, and a benefit of $2.4 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. In the fourth quarter of 2000, we eliminated our existing valuation allowance which resulted in the recognition of a $265.0 million income tax benefit. This resulted in an increase to 2000 net income of $265.0 million, or $1.75 per diluted share. Based upon results of operations for the year ended December 31, 2000 and anticipated improvement in Chesapeake's outlook for sustained profitability, we believed that it was more likely than not that we would generate sufficient future taxable income to realize the tax benefits associated with our NOL carryforwards prior to their expiration. 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. Our expectation remains unchanged as of December 31, 2002.

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. As of December 31, 2001, we classified $48.9 million of deferred tax assets related to NOLs as current which was offset by the current deferred tax liability attributable to the current portion of derivative assets.

At December 31, 2002, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $653.3 million. Additionally, we had $299.8 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $7.9 million of percentage depletion carryforwards. The NOL carryforwards expire from 2010 through 2022. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs. A summary of our NOLs follows:

	NOL	AMT NOL
	($ in thousands)	
Expiration Date:		
December 31, 2010	$ 6,698	$ —
December 31, 2011	1,298	363
December 31, 2012	222,782	1,175
December 31, 2018	149,687	49,346
December 31, 2019	229,420	217,545
December 31, 2020	5,156	4,900
December 31, 2021	12,700	11,424
December 31, 2022	25,542	15,042
Total	$ 653,283	$ 299,795

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. Of the $653.3 million NOLs and $299.8 million AMT NOLs, $346.4 million and $82.8 million, respectively, are limited under Section 382. Therefore, $306.9 million of the NOLs and $217.0 million of the AMT NOLs are not subject to the limitation. The utilization of $346.4 million of the NOLs and the utilization of $82.8 million of the AMT NOLs subject to the Section 382 limitation are limited to approximately $40.5 million and $14.9 million, respectively, each taxable year. Although no assurances can be made, we do not believe that an additional ownership change has occurred as of December 31, 2002. Equity transactions after the date hereof by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

6. Related Party Transactions

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. As of December 31, 2002, we had accrued accounts receivable from our CEO and COO of $1.0 million and $1.0 million, respectively, representing their December 2002 joint interest billings which were billed on January 15, 2003 and paid on January 16, 2003. Under their employment agreements, the CEO and COO are permitted to participate in all, or none, of the wells spudded by or on behalf of Chesapeake during each calendar quarter, but they are not allowed to only participate 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 2002, 2001 and 2000, we paid legal fees of $600,000, $391,000, and $439,000, respectively, for legal services provided by a law firm of which a director is a member.

7. Employee Benefit Plans

We maintain the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, a 401(k) profit sharing plan. Eligible employees may make voluntary contributions to the plan which Chesapeake matches up to 15% of the employee's annual compensation with Chesapeake's common stock purchased in the open-market. The amount of employee contribution is limited as specified in the plan. We may, at our discretion, make additional contributions to the plan. We contributed $2.9 million, $2.0 million and $1.5 million to the plan during 2002, 2001 and 2000, respectively.

In January 2003, Chesapeake established two nonqualified deferred compensation plans, as defined by the Internal Revenue Service. Participation by employees is limited to those having annual base compensation of at least $100,000. Additionally, the 401(k) Make-Up Plan has a five year service requirement. Any assets placed in trust by Chesapeake to fund future obligations of these plans are subject to the claims of creditors in the event of insolvency or bankruptcy.

Under the 401(k) Make-Up Plan, once eligible employees' contributions to Chesapeake's 401(k) plan have reached the Internal Revenue Service imposed maximum, they may defer compensation up to a total of 60% of their salary and 100% of performance bonus in the aggregate for the 401(k), 401(k) Make-Up Plan and the Deferred Compensation Plan. Chesapeake matches eligible employee contributions up to 15% of the employee's annual compensation with Chesapeake common stock. Under the Deferred Compensation Plan, eligible employees and non-employee directors may defer receipt of their compensation to some future date. Chesapeake has no requirement to make a matching contribution to the Deferred Compensation Plan.

8. Major Customers and Segment Information

Sales to individual customers constituting 10% or more of total oil and gas sales were as follows:

Year Ended December 31,	Customer	Amount	Percent of Oil and Gas Sales
		($ in thousands)	
2002	Continental Natural Gas	$ 90,161	14%
2002	Duke Energy Field Services	$ 71,373	11%
2002	Reliant Energy Field Services	$ 68,737	10%
2001	Continental Natural Gas	$ 102,286	14%
2001	Reliant Energy Field Services	$ 87,628	12%
2001	Aquila Southwest Pipeline Corporation	$ 71,868	10%
2000	Aquila Southwest Pipeline Corporation	$ 54,931	12%

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., which is our marketing segment, is the only non-guarantor subsidiary for all periods presented. The geographic distribution of our revenue, operating income and long-lived assets is summarized below:

	United States	Canada	Combined
		($ in thousands)	
2002:			
Revenue	$ 737,751	$ —	$ 737,751
Operating income	190,907	—	190,907
Long-lived assets	2,438,220	—	2,438,220
2001:			
Revenue	$ 937,123	$ 31,928	$ 969,051
Operating income	500,231	20,049	520,280
Long-lived assets	1,857,604	—	1,857,604
2000:			
Revenue	$ 594,126	$ 33,826	$ 627,952
Operating income	259,828	18,941	278,769
Long-lived assets	934,129	109,548	1,043,677

9. Stockholders' Equity and Stock-Based Compensation

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

In January 2001, we acquired Gothic Energy Corporation in a stock merger. We issued 4.0 million 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, 2002, 0.6 million shares of Chesapeake common stock may be purchased upon the exercise of such warrants and options at an average price of $14.27 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).

On March 30, 2001, we issued 1.1 million 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.

On November 13, 2001, we issued 3.0 million 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, 2002, 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, 2002, 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 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.

During 2000, we entered into a number of unsolicited transactions whereby we issued 43.4 million shares of our common stock, plus a cash payment of $8.3 million, in exchange for 3,972,363 shares of our 7% preferred stock. This reduced the liquidation amount of preferred stock outstanding by $198.6 million to $31.2 million and reduced the amount of preferred dividends in arrears by $22.9 million.

During 2000, Chesapeake Energy Marketing, Inc. purchased 99.8% of Gothic Energy Corporation's $104 million 14.125% Series B senior secured discount notes for total consideration of $80.8 million, comprised of $17.2 million in cash and $63.6 million of our common stock (8,875,775 shares valued at $7.16 per share), as adjusted for make-whole provisions. Chesapeake Energy Marketing, Inc. received $6.1 million in cash and $7.2 million of our common stock (982,562 shares) from the sellers of Gothic notes pursuant to make-whole provisions included in the purchase agreements.

In 2000, we purchased $31.6 million of the $235 million of 11.125% senior secured notes issued by Gothic Production Corporation for total consideration of $34.8 million consisting of $11.5 million in cash and $23.3 million of our common stock (3,694,939 shares valued at $6.30 per share), as adjusted for make-whole provisions. Through the make-whole provisions, we received cash of $1.0 million.

Stock-Based Compensation Plans

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 and sold may not exceed 50,000 shares. This plan was not required to be approved by our shareholders.

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 stock option 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 stock option 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 stock option 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 stock option 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 stock option 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.

Chesapeake's 1992 Incentive Stock Option Plan terminated on December 16, 1994. Until then, we granted incentive stock options to purchase our common stock under the plan to employees. 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 became exercisable at dates determined by the stock option committee of the board of directors. This plan was approved by our shareholders.

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

	Years Ended December 31,					
	2002		2001		2000	
	Options	Weighted-Avg Exercise Price	Options	Weighted-Avg Exercise Price	Options	Weighted-Avg Exercise Price
Outstanding Beginning of Period	23,232,655	$ 3.96	18,399,162	$ 2.83	12,858,429	$ 1.76
Granted	4,170,700	5.38	7,422,300	6.18	8,143,280	4.08
Exercised	(2,519,429)	1.83	(2,264,374)	1.83	(2,177,644)	1.21
Canceled/Forfeited	(307,151)	5.30	(324,433)	5.68	(424,903)	2.47
Outstanding End of Period	24,576,775	$ 4.40	23,232,655	$ 3.96	18,399,162	$ 2.83
Exercisable End of Period	11,014,775	$ 3.55	7,495,255	$ 2.88	5,422,884	$ 2.61
Shares Authorized for Future Grants	7,602,339		3,836,856		588,435	
Fair Value of Options Granted During the Period	$ 2.31		$ 3.34		$ 2.63	

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following table summarizes information about stock options outstanding at December 31, 2002:

	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-$0.94	1,781,203	4.95	$ 0.87	1,209,787	$ 0.84
1.00-1.13	3,195,191	5.76	1.13	3,195,191	1.13
1.33-2.25	2,456,273	5.50	2.22	1,343,609	2.20
2.43-4.00	2,632,337	6.93	3.90	1,378,911	3.81
4.06-5.20	3,717,437	9.52	5.19	28,935	4.34
5.35-5.56	2,798,879	7.87	5.56	1,347,993	5.56
5.60-6.10	198,813	7.52	5.78	94,753	5.69
6.11-6.11	6,848,669	8.74	6.11	1,694,705	6.11
6.13-14.25	847,973	6.95	7.48	620,891	7.59
30.62-30.63	100,000	3.12	30.63	100,000	30.63
$0.56-$30.63	24,576,775	7.48	$ 4.40	11,014,775	$ 3.55

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 2002, 2001 and 2000, we recognized a tax benefit of $2.4 million, $5.4 million and $3.8 million, which was 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

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

effectiveness for accounting purposes, 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, we receive a fixed price for the hedged commodity and pay a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a “cap” limiting the counterparty’s exposure.
- Basis protection swaps are arrangements that guarantee a price differential of oil and 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.

From time to time, we close certain swap and cap-swap transactions designed to hedge a portion of our oil and natural gas production by entering into a counter-swap instrument. Under the counter-swap we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. To the extent the counter-swap, which does not qualify for hedge accounting under SFAS 133, is designed to lock the value of an existing SFAS 133 cash flow hedge, the net value of the swap and the counter-swap is frozen and shown as a derivative receivable or payable in the consolidated balance sheets. At the same time, the original swap is designated as a non-qualifying cash flow hedge under SFAS 133. The net receivable or payable is frozen until the related month of production and is then recognized as an increase or decrease to revenues. Changes in fair value occurring after the original swap has been designated as a non-qualifying cash flow hedge under SFAS 133 are included in results of operations. To the extent the counter-swap is designed to lock the value of a non-qualifying cash flow hedge under SFAS 133, the value of the counter-swap is shown as a derivative asset or liability in the consolidated balance sheet and referred to below as a fixed-price counter-swap. Any changes in the fair value of the counter-swap are included in results of operations.

Pursuant to SFAS 133, our cap-swaps, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. Therefore, changes in the fair value of these instruments that occur prior to their maturity, together with any changes in fair value of cash flow hedges resulting from ineffectiveness, are reported in the consolidated statements of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive SFAS 133 cash flow hedge accounting treatment. All amounts initially recorded in this caption related to commodity derivatives are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

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

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

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

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

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

Risk management income (loss) related to our oil and gas derivatives is comprised of the following:

	December 31,	
	2002	2001
	($ in thousands)	
Risk management income (loss):		
Change in fair value of derivatives not qualifying for hedge accounting	$ (23,979)	$ 106,825
Reclassification of gain on settled contracts	(59,729)	(24,540)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(3,559)	2,504
Total	$ (87,267)	$ 84,789

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Interest Rate Hedging

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

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

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

At the inception of the interest rate swap agreement, a portion of the interest rate swap was to convert $129.0 million of the 7.875% senior notes from fixed rate debt to variable rate debt. Under SFAS 133, a hedge of interest rate risk in a recognized fixed rate liability can be designated as a fair value hedge under which the mark-to-market value of the swap is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease in the carrying value of the debt. During the Current Period, $107.9 million face value, of the 7.875% senior notes were purchased and subsequently retired. In connection with the repurchase of the 7.875% senior notes, interest rate swap hedging gains of $1.7 million were recognized in the Current Period, and reduced the loss on repurchases of debt.

In July 2002, we closed the above interest rate swap for a gain of $7.5 million. As of December 31, 2002, the remaining balance to be amortized as a reduction to interest expense was $2.6 million. During 2002, $3.2 million was recognized as a reduction to interest expense.

In June 2002, we entered into an additional interest rate swap. The terms of this swap agreement are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
July 2002 – July 2004	$100,000,000	4.000%	U.S. six-month LIBOR in arrears

In July 2002, we closed this interest rate swap for a gain of $1.1 million. As of December 31, 2002, the remaining balance to amortize as a reduction to interest expense was $0.9 million. During 2002, $0.2 million was recognized as a reduction to interest expense.

In April 2002, we entered into a swaption agreement in order to monetize the embedded call option in the remaining $142.7 million of our 8.5% senior notes. We received $7.8 million from the counterparty at the time we entered into this agreement. The terms of the swaption are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
March 2004 – March 2012	$142,665,000	8.500%	U.S. six-month LIBOR plus 75 basis points

Under the terms of the swaption agreement, the counterparty will have the option to initiate an interest rate swap on March 11, 2004 pursuant to the terms shown above. If the counterparty chooses to initiate the interest rate swap, the payments under the swap will coincide with the semi-annual interest payments on our 8.5% senior notes which are paid on September 15 and March 15 of each year. On each payment date, if the fixed rate exceeds the floating rate, we will pay the counterparty and if the floating rate exceeds the fixed rate, the counterparty will pay us accordingly. If the counterparty does not choose to initiate the interest rate swap, the swaption agreement will expire and no future obligations will exist for either party.

Under SFAS 133, a fair value hedge relationship exists between the embedded call option in the debt and the swaption agreement. Accordingly, the mark-to-market value of the swaption is recorded on the consolidated balance sheet as an asset or liability with a corresponding increase or decrease to the debt's carrying value. Any change in the fair value of the swaption resulting from ineffectiveness is recorded currently in the consolidated statements of operations as risk management income (loss).

We have recorded a decrease in the carrying value of the debt of $18.8 million during 2002 related to the swaption as of December 31, 2002. Of this amount, $22.3 million represents a decline in the fair value of the swaption, offset by a loss of $3.5 million from estimated ineffectiveness of the swaption as determined under SFAS 133. See Note 3 for the adjustments made to the carrying value of the debt at December 31, 2002. Results of the interest rate swap, if initiated, will be reflected as adjustments to interest expense in the corresponding months covered by the swaption agreement.

Risk management income (loss) related to our fair value hedges is comprised of the following ($ in thousands):

	2002
	($ in thousands)
Risk management income (loss):	
Change in fair value of derivatives not qualifying for fair value hedge accounting	$ 4,593
Reclassification of gain on settled contracts to interest expense	(1,844)
Ineffective portion of derivatives qualifying for fair value hedge accounting	(3,500)
Total	$ (751)

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 (including current maturities), fixed-rate debt using primarily quoted market prices. Our carrying amount for such debt at December 31, 2002 and 2001 was $1,669.3 million and $1,330.1 million, respectively, compared to approximate fair values of $1,744.7 million and $1,343.0 million, respectively. The carrying amount for our 6.75% convertible preferred stock at December 31, 2002 was $149.9 million, with a fair value of $181.5 million.

Concentration of Credit Risk

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

December 31, 2002	U.S.
	($ 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

December 31, 2001	U.S.
	($ in thousands)
Oil and gas properties:	
Proved	$ 3,546,163
Unproved	66,205
Total	3,612,368
Less accumulated depreciation, depletion and amortization	(1,902,587)
Net capitalized costs	$ 1,709,781

Unproved properties not subject to amortization at December 31, 2002 and 2001 consisted mainly of lease acquisition costs. We capitalized approximately $5.0 million, $4.7 million and $2.4 million of interest during 2002, 2001 and 2000, 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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, 2002	U.S.	Canada	Combined
		($ in thousands)	
Development and leasehold costs	$ 296,426	$ —	$ 296,426
Exploration costs	89,422	—	89,422
Acquisition costs:			
Proved	316,583	—	316,583
Unproved	14,000	—	14,000
Deferred tax adjustments	62,398	—	62,398
Sales of oil and gas properties	(839)	—	(839)
Capitalized internal costs	16,981	—	16,981
Total	$ 794,971	$ —	$ 794,971

Year Ended December 31, 2001	U.S.	Canada(a)	Combined
		($ in thousands)	
Development and leasehold costs	$ 335,024	$ 11,090	$ 346,114
Exploration costs	47,937	8	47,945
Acquisition costs:			
Proved	669,201	—	669,201
Unproved	35,132	—	35,132
Deferred tax adjustments	36,309	—	36,309
Sales of oil and gas properties	(1,138)	(150,306)	(151,444)
Capitalized internal costs	12,914	—	12,914
Total	$ 1,135,379	$ (139,208)	$ 996,171

Year Ended December 31, 2000	U.S.	Canada	Combined
		($ in thousands)	
Development and leasehold costs	$ 135,049	$ 13,559	$ 148,608
Exploration costs	24,648	10	24,658
Acquisition costs:			
Proved	75,285	—	75,285
Unproved	3,625	—	3,625
Sales of oil and gas properties	(1,529)	—	(1,529)
Capitalized internal costs	10,194	—	10,194
Total	$ 247,272	$ 13,569	$ 260,841

(a) 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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 2002, 2001 and 2000. 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, 2002	U.S.	Canada	Combined
		($ in thousands)	
Oil and gas sales	$ 655,454	$ —	$ 655,454
Production expenses	(98,191)	—	(98,191)
Production taxes	(30,101)	—	(30,101)
Depletion and depreciation	(221,189)	—	(221,189)
Imputed income tax provision (a)	(122,389)	—	(122,389)
Results of operations from oil and gas producing activities	$ 183,584	$ —	$ 183,584

Year Ended December 31, 2001	U.S.	Canada	Combined
		($ in thousands)	
Oil and gas sales	$ 703,601	$ 31,928	$ 735,529
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)	(173,153)	(9,612)	(182,765)
Results of operations from oil and gas producing activities	$ 259,729	$ 11,749	$ 271,478

Year Ended December 31, 2000	U.S.	Canada	Combined
		($ in thousands)	
Oil and gas sales	$ 436,344	$ 33,826	$ 470,170
Production expenses	(46,280)	(3,805)	(50,085)
Production taxes	(24,840)	—	(24,840)
Depletion and depreciation	(92,708)	(8,583)	(101,291)
Imputed income tax provision (a)	(103,556)	(9,647)	(113,203)
Results of operations from oil and gas producing activities	$ 168,960	$ 11,791	$ 180,751

(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.

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, 2002, Lee Keeling and Associates, Ryder Scott 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

- As of December 31, 2001, Ryder Scott, Lee Keeling and Associates, Williamson and our internal reservoir engineers evaluated 26%, 24%, 22% and 28%, respectively, of the combined discounted future net revenues from our estimated proved reserves.
- As of December 31, 2000, Williamson, Ryder Scott, Lee Keeling and Associates and our internal reservoir engineers evaluated 31%, 25%, 16% 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. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods.

Presented below is a summary of changes in estimated reserves of Chesapeake for 2002, 2001 and 2000:

December 31, 2002

	U.S.			Canada			Combined		
	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2001

	U.S.			Canada			Combined		
	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
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

December 31, 2000

	U.S.			Canada			Combined		
	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
Proved reserves, beginning of period	24,795	878,584	1,027,353	—	178,242	178,242	24,795	1,056,826	1,205,595
Extensions, discoveries and other additions	3,599	157,719	179,313	—	20,772	20,772	3,599	178,491	200,085
Revisions of previous estimates	(3,210)	25,652	6,392	—	(27,973)	(27,973)	(3,210)	(2,321)	(21,581)
Production	(3,068)	(103,694)	(122,102)	—	(12,077)	(12,077)	(3,068)	(115,771)	(134,179)
Sale of reserves-in-place	(136)	(2,155)	(2,971)	—	—	—	(136)	(2,155)	(2,971)
Purchase of reserves-in-place	1,817	96,963	107,864	—	—	—	1,817	96,963	107,864
Proved reserves, end of period	23,797	1,053,069	1,195,849	—	158,964	158,964	23,797	1,212,033	1,354,813
Proved developed reserves:									
Beginning of period	17,750	627,120	733,620	—	136,203	136,203	17,750	763,323	869,823
End of period	15,445	739,775	832,445	—	118,688	118,688	15,445	858,463	951,133

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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

During 2000, Chesapeake acquired 108 bcfe of proved reserves for consideration of $75 million (primarily in two separate transactions of greater than $10.0 million each). Also during 2000, we recorded downward revisions to our U.S. oil reserves of 3.2 million barrels and upward revisions to our U.S. natural gas reserves of 25.7 bcf. The downward revisions to our U.S. oil reserves were related to lower estimates primarily in the Knox, Permian and Williston areas. The upward revisions to our U.S. gas reserves were due primarily to additional reserves added as a result of the significant increase in natural gas prices as of December 31, 2000, which had the effect of extending the economic life of our properties. These upward revisions were partially offset by the elimination of proved undeveloped locations primarily in the Knox, Independence and Sahara fields, as well as lower estimates in various areas located primarily in the Mid-Continent area. During 2000, we also had negative revisions to our Canadian gas reserves of 28 bcf. This decrease was primarily due to the increase in crown royalties resulting from higher natural gas prices at December 31, 2000, as well as lower estimates on various properties in the Helmet field.

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. 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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:

December 31, 2002

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

December 31, 2001

	U.S.	Canada	Combined
		($ in thousands)	
Future cash inflows(b)	$ 4,586,743	$ —	$ 4,586,743
Future production costs	(1,169,199)	—	(1,169,199)
Future development costs	(450,181)	—	(450,181)
Future income tax provision	(484,474)	—	(484,474)
Net future cash flows	2,482,889	—	2,482,889
Less effect of a 10% discount factor	(1,021,916)	—	(1,021,916)
Standardized measure of discounted future net cash flows	$ 1,460,973	$ —	$ 1,460,973
Discounted (at 10%) future net cash flows before income taxes	$ 1,646,667	$ —	$ 1,646,667

December 31, 2000

	U.S.	Canada	Combined
		($ in thousands)	
Future cash inflows(c)	$ 11,336,112	$ 1,540,158	$ 12,876,270
Future production costs	(1,778,325)	(79,427)	(1,857,752)
Future development costs	(294,359)	(21,185)	(315,544)
Future income tax provision	(3,247,701)	(447,887)	(3,695,588)
Net future cash flows	6,015,727	991,659	7,007,386
Less effect of a 10% discount factor	(2,440,407)	(503,718)	(2,944,125)
Standardized measure of discounted future net cash flows	$ 3,575,320	$ 487,941	$ 4,063,261
Discounted (at 10%) future net cash flows before income taxes	$ 5,365,228	$ 680,800	$ 6,046,028

(a) Calculated using weighted average prices of $30.18 per barrel of oil and $4.28 per mcf of gas.
(b) Calculated using weighted average prices of $18.82 per barrel of oil and $2.51 per mcf of gas.
(c) Calculated using weighted average prices of $26.41 per barrel of oil and $10.12 per mcf of gas.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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, 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	(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	$ 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	(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	$ 1,460,973	$ —	$ 1,460,973

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2000

	U.S.	Canada	Combined
		($ in thousands)	
Standardized measure, beginning of period	$ 908,898	$ 97,714	$ 1,006,612
Sales of oil and gas produced, net of production costs	(365,224)	(30,021)	(395,245)
Net changes in prices and production costs	2,750,651	573,654	3,324,305
Extensions and discoveries, net of production and development costs	878,128	87,647	965,775
Changes in future development costs	2,167	3,233	5,400
Development costs incurred during the period that reduced future development costs	38,112	6,415	44,527
Revisions of previous quantity estimates	25,818	(113,473)	(87,655)
Purchase of reserves-in-place	494,483	—	494,483
Sales of reserves-in-place	(3,113)	—	(3,113)
Accretion of discount	99,175	9,775	108,950
Net change in income taxes	(1,707,060)	(192,825)	(1,899,885)
Changes in production rates and other	453,285	45,822	499,107
Standardized measure, end of period	$ 3,575,320	$ 487,941	$ 4,063,261

12. Acquisitions and Divestitures

Acquisitions. During 2002, 2001 and 2000, we acquired working interests in proved oil and gas properties for total consideration of $379.0 million, $705.5 million and $75.3 million, respectively. All of the acquisitions were accounted for using the purchase method and, accordingly, results of operations of these acquired entities and oil and gas properties have been included in Chesapeake's results of operations from the respective effective dates of acquisition.

Acquisition of Gothic Energy Corporation. We completed the acquisition of Gothic Energy Corporation on January 16, 2001 by merging a wholly-owned subsidiary into Gothic. We issued a total of 4.0 million common shares in the merger. Gothic shareholders (other than Chesapeake) received 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, 2002, 0.6 million shares of Chesapeake common stock may be purchased upon the exercise of such warrants and options at an average price of $14.27 per share. In 2000, Chesapeake purchased substantially all of Gothic's 14.125% senior secured discount notes for total consideration of $80.8 million in cash and Chesapeake common stock. We also purchased $31.6 million principal amount of 11.125% senior secured notes due 2005 issued by Gothic's operating subsidiary for total consideration of $34.8 million in cash and Chesapeake common stock. Subsequent to the acquisition, we redeemed all remaining Gothic 14.125% discount notes for total consideration of $243,000. In February 2001, we purchased $1.0 million principal amount of Gothic senior secured notes tendered pursuant to a change-of-control offer at a purchase price of 101%. During April and May 2001, we purchased or redeemed the remaining $202.3 million of Gothic 11.125% senior secured notes for total consideration of $225.9 million. On May 14, 2001, Gothic Energy Corporation and Gothic Production Corporation became guarantor subsidiaries of Chesapeake's senior notes.

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

The acquisition of Gothic was accounted for using the purchase method as of January 1, 2001 because we had effective control as of that date, and the results of operations of Gothic have been included since that date.

The following unaudited pro forma information has been prepared assuming Gothic had been acquired as of the beginning of the period presented. The pro forma information is presented for information purposes only and is not necessarily indicative of what would have occurred if the acquisition had been made as of that date. In addition, the pro forma information is not intended to be a projection of future results and does not reflect any efficiencies that may have resulted from the integration of Gothic.

Pro Forma Information
(unaudited)
($ in thousands, except per share data)

	2000
Revenues	$ 711,017
Income before income taxes	196,740
Net income	458,350
Earnings per common share-basic	3.27
Earnings per common share-assuming dilution	2.83

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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

13. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2002 and 2001 are as follows ($ in thousands except per share data):

	Quarters Ended			
	March 31, 2002	June 30, 2002	September 30, 2002	December 31, 2002
Total Revenues	$ 89,836	$ 194,313	$ 198,182	$ 255,420
Gross profit(a)	(19,970)	62,690	59,439	88,748
Net income	(27,586)	25,033	16,600	26,239
Net earnings per common share:				
Basic:				
Income (loss) before extraordinary item	(0.18)	0.14	0.08	0.14
Extraordinary item	—	—	—	—
Net Income (loss)	(0.18)	0.14	0.08	0.14
Diluted:				
Income (loss) before extraordinary item	(0.18)	0.13	0.08	0.13
Extraordinary item	—	—	—	—
Net Income (loss)	(0.18)	0.13	0.08	0.13

	Quarters Ended			
	March 31, 2001	June 30, 2001	September 30, 2001	December 31, 2001
Total Revenues	$ 277,384	$ 275,681	$ 238,911	$ 177,075
Gross profit(a)	146,696	165,315	132,374	75,895
Net income	70,288	39,485(b)	65,008	42,625(c)
Net earnings per common share:				
Basic:				
Income before extraordinary item	0.44	0.52	0.40	0.25
Extraordinary item	—	(0.28)	—	—
Net Income	0.44	0.24	0.40	0.25
Diluted:				
Income before extraordinary item	0.41	0.50	0.38	0.23
Extraordinary item	—	(0.27)	—	—
Net Income	0.41	0.23	0.38	0.23

(a) Total revenue less total operating costs.
(b) Net of an extraordinary loss on extinguishment of debt of $46.0 million, net of income taxes.
(c) Includes pretax gain on sale of Canadian subsidiary of $27.0 million and pretax impairments of investments in securities of $10.1 million.

14. Recent Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board, or FASB, issued Statement of Financial Accounting Standards or SFAS Nos. 141 and 142. SFAS 141, *Business Combinations*, requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. SFAS 142, *Goodwill and Other Intangible Assets*, changes the accounting for goodwill from an amortization method to an impairment-only approach and was effective in January 2002. We have adopted these new standards, which have not had a significant effect on our results of operations or our financial position.

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS 143 is effective for fiscal years beginning after June 15, 2002 and establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-term assets (mainly plugging and abandonment costs for depleted wells) in the period in which the liability is incurred (at the time the wells are drilled). Accordingly, we adopted this standard in the first quarter of 2003. We expect the effect on our financial condition and results of operations at adoption will include an increase in liabilities of approximately $39 million and a cumulative effect for the change in accounting principle as a charge against earnings of approximately $10 million (net of income taxes). Subsequent to adoption, we do not expect this standard to have a material impact on our financial position or results of operations.

In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS 144 was effective January 1, 2002. This statement supersedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of*, and amends Accounting Principles Board Opinion, or APB, No. 30 for the accounting and reporting of discontinued operations, as it relates to long-lived assets. Our adoption of SFAS 144 did not affect our financial position or results of operations.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. SFAS 145 is effective for fiscal years beginning after May 15, 2002. We have adopted this standard early and it did not have a significant effect on our results of operations or our financial position.

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 do not expect the adoption of this standard to have any impact on our financial position or results of operations.

On December 31, 2002, the FASB issued SFAS No.148, *Accounting for Stock-Based Compensation – Transition and Disclosure – An Amendment of SFAS 123.* The standard provides additional transition guidance for companies that elect to voluntarily adopt the accounting provisions of SFAS 123, *Accounting for Stock-Based Compensation*. SFAS 148 does not change the provisions of SFAS 123 that permit entities to continue to apply the intrinsic value method of APB 25, *Accounting for Stock Issued to Employees*. As we continue to follow APB 25, our accounting for stock-based compensation will not change as a result of SFAS 148. SFAS 148 does require certain new disclosures in both annual and interim financial statements. The required annual disclosures are effective immediately and have been included in Note 1 of our consolidated financial statements included in Item 8. The new interim disclosure provisions will be effective in the first quarter of 2003.

In November 2002 the FASB issued FASB Interpretation No., 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.

On January 17, 2003, the FASB issued FIN 46, *Consolidation of Variable Interest Entities, An Interpretation of ARB 51*. The primary objectives of FIN 46 are to provide guidance on how to identify entities for which control is achieved through means other than through voting rights (variable interest entities or VIEs) and how to determine when and which business enterprise should consolidate the VIE. This new model for consolidation applies to an entity in which either (1) the equity investors do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties. We do not expect the adoption of this standard to have any impact on our financial position or results of operations.

15. Subsequent Events

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

On February 24, 2003, we announced that we had entered into an agreement to acquire El Paso Corporation's Anadarko Basin assets in western Oklahoma and the Texas Panhandle for $500 million. We expect to close the El Paso acquisition in March 2003.

On February 24, 2003, we announced that we had entered into an agreement to acquire Vintage Petroleum, Inc.'s assets in the Bray field in southern Oklahoma for $30 million. We expect to close the Vintage acquisition in March 2003.

On February 24, 2003, we announced a proposed private placement of $300 million in aggregate principal amount of senior notes, a proposed public offering of 20,000,000 shares of common stock pursuant to our existing shelf registration statement and a proposed private placement of $200 million of convertible preferred stock. There is no assurance these proposed offerings will be completed or, if they are completed, that they will be completed for the amount contemplated.

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, 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(b)	$ —	$ —	$ 2,441
December 31, 2000:					
Allowance for doubtful accounts	$ 3,218	$ 256	$ —	$ 2,389	$ 1,085
Valuation allowance for deferred tax assets	$ 442,016	$ —	$ —	$ 442,016(a)	$ —

(a) In the fourth quarter of 2000, we eliminated the valuation allowance for deferred tax assets. The reversal was based upon recent results of operations and anticipated improvements in Chesapeake's outlook for sustained profitability. During 2000, we revised our estimate of the 1999 U.S. net deferred tax asset and related valuation allowance from $442 million to $330 million as a result of further evaluation of the income tax basis of several acquisitions.

(b) At 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 have recorded a valuation allowance equal to such amount.

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

Not applicable.

PART III

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

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2003.

ITEM 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2003.

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

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2003.

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

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2003.

ITEM 14. ***Controls and Procedures***

Within the 90-day period prior to the filing of this report, the company carried out an evaluation, under the supervision and with the participation of the company’s management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the company’s disclosure controls and procedures (as defined in Rule 13a-14(c) under the Securities Exchange Act of 1934). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the company’s disclosure controls and procedures are effective in timely alerting them to material information relating to the company (including its consolidated subsidiaries) required to be included in the company’s periodic SEC filings. There have been no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

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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
2.1*	—Purchase and Sale Agreement by and between El Paso Production Company and Noric, L.P. as Seller and Chesapeake EP Corporation as Buyer dated February 21, 2003.
3.1	—Chesapeake's Restated Certificate of Incorporation together with the Certificate of Designation for the 6.75% Cumulative Convertible Preferred Stock of Chesapeake and the Certificate of Designation for the Series A Junior Participating Preferred Stock of Chesapeake. Incorporated herein by reference as Exhibit 3.1 to Chesapeake's registration statement on Form S-3 filed July 22, 2002.
3.1.1	—Certificate of Elimination filed November 4, 2002 with the Secretary of State of the State of Oklahoma. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake's registration statement on Form S-4 filed January 10, 2003.
3.2	—Chesapeake's Bylaws. Incorporated herein by reference to Exhibit 3.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001.
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

Exhibit Number	Description
	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).
4.1.1*	—Twelfth Supplemental Indenture dated as of February 14, 2003 to Indenture dated as of March 15, 1997 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 7.875% Senior Notes due 2004.
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 Supplemental 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 Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.2.3 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 4.2.1 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 4.2.2 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).
4.2.1*	—Twelfth Supplemental Indenture dated as of February 14, 2003 to Indenture dated as of March 15, 1997 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 8.5% Senior Notes due 2012.
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

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Exhibit Number	Description
	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).
4.3.1*	—Seventh Supplemental Indenture dated as of February 14, 2003 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 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).
4.4.1*	—Fourth Supplemental Indenture dated as of February 14, 2003 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).
4.5.1*	—First Supplemental Indenture dated as of February 14, 2003 to 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 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).
4.6.1*	—First Supplemental Indenture dated as of February 14, 2003 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	—$225,000,000 Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, BNP Paribas and Toronto Dominion (Texas), Inc., as

Exhibit Number	Description
	Co-Documentation Agents and other lenders party thereto. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001. Consent and waiver letter dated September 10, 2001 and consent and waiver letter dated October 5, 2001. Incorporated herein by reference to Exhibits 4.6.1 and 4.6.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001, respectively. Consent and waiver letter dated November 2, 2001. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's registration statement on Form S-4 (No. 333-74584). First Amendment dated March 8, 2002 with respect to Second Amended and Restated Credit Agreement. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2001. Consent and waiver letter dated April 15, 2002. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2002. Second Amendment dated June 4, 2002 with respect to Second Amended and Restated Credit Agreement. Incorporated by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2002. Consent and waiver letter dated August 2, 2002. Incorporated herein by reference to Exhibit 4.6.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Third Amendment dated September 20, 2002, with respect to the Second Amended and Restated Credit Agreement. Incorporated herein by reference to Exhibit 4.6.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2002. Fourth Amendment dated November 4, 2002, with respect to the Second Amended and Restated Credit Agreement. Incorporated herein by reference to Exhibit 4.6.4 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2002. Consent and waiver letter dated December 11, 2002 with respect to the Second Amended and Restated Credit Agreement. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's registration statement on Form S-4 (No. 333-102446).
4.9	—Warrant Agreement dated as of September 9, 1997 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent, and Supplement to Warrant Agreement dated as of January 16, 2001. Incorporated herein by reference to Exhibit 4.9 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
4.10	—Registration Rights Agreement dated as of September 9, 1997 among Gothic Energy Corporation, two of its subsidiaries, Oppenheimer & Co., Inc., Banc One Capital Corporation and Paribas Corporation. Incorporated herein by reference to Exhibit 4.10 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
4.11	—Warrant Agreement dated as of January 23, 1998 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent. Incorporated herein by reference to Exhibit 4.11 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
4.12	—Common Stock Registration Rights Agreement dated as of January 23, 1998 among Gothic Energy Corporation and purchasers of its senior redeemable preferred stock. Incorporated herein by reference to Exhibit 4.12 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
4.14	—Warrant Agreement dated as of April 21, 1998 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent, and Supplement to Warrant Agreement dated as of January 16, 2001. Incorporated herein by reference to Exhibit 4.14 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
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.

Exhibit Number	Description
10.1.1†	—Chesapeake's 1992 Incentive Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.1 to Chesapeake's registration statement on Form S-4 (No. 33-93718).
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.
10.1.15†*	—Chesapeake Energy Corporation 401(k) Make-Up Plan.
10.1.16†*	—Chesapeake Energy Corporation Deferred Compensation Plan.
10.2.1†	—Second Amended and Restated Employment Agreement dated as of July 1, 2001, between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 4.7 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001.

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Exhibit Number	Description
10.2.2†	—Second Amended and Restated Employment Agreement dated as of July 1, 2001, between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 4.8 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001.
10.2.3†	—Amended and Restated Employment Agreement dated as of August 1, 2000 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Chesapeake's registration statement on Form S-1 (No. 333-45872).
10.2.8†	—Employment Agreement dated as of July 1, 2000 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 June 30, 2000.
10.2.9†	—Employment Agreement dated as of July 1, 2000 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 June 30, 2000.
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
23.1*	—Consent of PricewaterhouseCoopers LLP
23.2*	—Consent of Williamson Petroleum Consultants, Inc.
23.3*	—Consent of Ryder Scott Company L.P.
23.4*	—Consent of Lee Keeling and Associates, Inc.
23.5*	—Consent of Netherland, Sewell and Associates, Inc.
99.1*	—Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.2*	—Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification 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.

(b) Reports on Form 8-K

During the quarter ended December 31, 2002, Chesapeake filed the following current reports on Form 8-K:

On October 3, 2002, we filed a current report on Form 8-K furnishing under Item 9 that we had issued a press release announcing the third quarter 2002 earnings release date and conference call.

On November 5, 2002, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release announcing third quarter 2002 earnings. We furnished under Item 9 updates to our operational and financial guidance for the fourth quarter of 2002 and full year 2003.

On December 5, 2002, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 4, 2002, in accordance with SEC rule 135C, announcing a private offering of senior notes.

On December 5, 2002, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 4, 2002 announcing an agreement to acquire $300 million of Mid-Continent gas reserves from ONEOK, Inc.

On December 5, 2002, we filed a current report on Form 8-K, furnishing under Item 9 that we issued a press release on December 4, 2002 announcing our updated 2003 forecast.

On December 6, 2002, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 5, 2002 announcing an offering of common stock.

On December 13, 2002, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 13, 2002 announcing the pricing of our public offering of common stock.

On December 16, 2002, we filed a current report on Form 8-K, reporting under Item 5 that we entered into an underwriting agreement with Credit Suisse First Boston Corporation, Morgan Stanley & Co. Incorporated, Salomon Smith Barney Inc., Bear, Stearns & Co. Inc., Lehman Brothers Inc. and Johnson Rice and Company L.L.C. in connection with the issuance and sale of 20,000,000 shares of our common stock, plus an additional 3,000,000 shares of common stock pursuant to the underwriters' over-allotment option. In addition, we filed the underwriting agreement under Item 7.

On December 16, 2002, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 16, 2002 announcing the pricing of $150 million of 7.75% senior notes due 2015.

On December 20, 2002, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on December 20, 2002 announcing the declaration of quarterly common and preferred stock dividends.

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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: February 26, 2003

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

Name	Title	Date
/S/ AUBREY K. MCCLENDON **Aubrey K. McClendon**	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	
/S/ TOM L. WARD **Tom L. Ward**	President, Chief Operating Officer and Director (Principal Executive Officer)	
/S/ MARCUS C. ROWLAND **Marcus C. Rowland**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	
/S/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President—Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	
EDGAR F. HEIZER, JR. **Edgar F. Heizer, Jr.**	Director	
/S/ BREENE M. KERR **Breene M. Kerr**	Director	
/S/ SHANNON T. SELF **Shannon T. Self**	Director	
/S/ FREDERICK B. WHITTEMORE **Frederick B. Whittemore**	Director	
/S/ CHARLES T. MAXWELL **Charles T. Maxwell**	Director	

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 annual 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   (a) designed such disclosure controls and procedures 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 annual report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, 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 in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 26, 2003

By: /S/ AUBREY K. MCCLENDON

Aubrey K. McClendon
Chairman and Chief Executive Officer

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CERTIFICATION

I, Marcus C. Rowland certify that:

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

2. Based on my knowledge, this annual 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   (a) designed such disclosure controls and procedures 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 annual report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, 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 in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 26, 2003

By: /S/ MARCUS C. ROWLAND

Marcus C. Rowland
Executive Vice President and Chief Financial Officer

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INDEX TO EXHIBITS

Exhibit Number	Description
2.1*	—Purchase and Sale Agreement By and Between El Paso Production Company and Noric, L.P. as Seller and Chesapeake EP Corporation as Buyer dated February 21, 2003.
3.1	—Chesapeake's Restated Certificate of Incorporation together with the Certificate of Designation for the 6.75% Cumulative Convertible Preferred Stock of Chesapeake and the Certificate of Designation for the Series A Junior Participating Preferred Stock of Chesapeake. Incorporated herein by reference to Exhibit 3.1 to Chesapeake's registration statement on Form S-3 filed July 22, 2002.
3.1.1	—Certificate of Elimination filed November 4, 2002 with the Secretary of State of the State of Oklahoma. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake's registration statement on Form S-4 filed January 10, 2003.
3.2	—Chesapeake's Bylaws. Incorporated herein by reference to Exhibit 3.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001.
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).
4.1.1*	—Twelfth Supplemental Indenture dated as of February 14, 2003 to Indenture dated as of March 15, 1997 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 7.875% Senior Notes due 2004.
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

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Exhibit Number	Description
	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 Supplemental 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 Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.2.3 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 4.2.1 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 4.2.2 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).
4.2.1*	—Twelfth Supplemental Indenture dated as of February 14, 2003 to Indenture dated as of March 15, 1997 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 8.5% Senior Notes due 2012.
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).
4.3.1*	—Seventh Supplemental Indenture dated as of February 14, 2003 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 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

Exhibit Number	Description
	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).
4.4.1*	—Fourth Supplemental Indenture dated as of February 14, 2003 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).
4.5.1*	—First Supplemental Indenture dated as of February 14, 2003 to 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 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).
4.6.1*	—First Supplemental Indenture dated as of February 14, 2003 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	—$225,000,000 Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, BNP Paribas and Toronto Dominion (Texas), Inc., as Co-Documentation Agents and other lenders party thereto. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001. Consent and waiver letter dated September 10, 2001 and consent and waiver letter dated October 5, 2001. Incorporated herein by reference to Exhibits 4.6.1 and 4.6.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001, respectively. Consent and waiver letter dated November 2, 2001. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's registration statement on Form S-4 (No. 333-74584). First Amendment dated March 8, 2002 with respect to Second Amended and Restated Credit Agreement. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2001. Consent and waiver letter dated April 15, 2002. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2002. Second Amendment dated June 4, 2002 with respect to Second Amended and Restated Credit Agreement. Incorporated by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2002. Consent and waiver letter dated August 2, 2002. Incorporated herein by reference to Exhibit 4.6.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Third Amendment dated September 20, 2002, with respect to the Second Amended and Restated Credit Agreement. Incorporated herein by reference to Exhibit 4.6.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2002. Fourth Amendment dated

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Exhibit Number	Description
	November 4, 2002, with respect to the Second Amended and Restated Credit Agreement. Incorporated herein by reference to Exhibit 4.6.4 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2002. Consent and waiver letter dated December 11, 2002 with respect to the Second Amended and Restated Credit Agreement. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's registration statement on Form S-4 (No. 333-102446).
4.9	—Warrant Agreement dated as of September 9, 1997 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent, and Supplement to Warrant Agreement dated as of January 16, 2001. Incorporated herein by reference to Exhibit 4.9 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
4.10	—Registration Rights Agreement dated as of September 9, 1997 among Gothic Energy Corporation, two of its subsidiaries, Oppenheimer & Co., Inc., Banc One Capital Corporation and Paribas Corporation. Incorporated herein by reference to Exhibit 4.10 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
4.11	—Warrant Agreement dated as of January 23, 1998 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent. Incorporated herein by reference to Exhibit 4.11 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
4.12	—Common Stock Registration Rights Agreement dated as of January 23, 1998 among Gothic Energy Corporation and purchasers of its senior redeemable preferred stock. Incorporated herein by reference to Exhibit 4.12 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
4.14	—Warrant Agreement dated as of April 21, 1998 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent, and Supplement to Warrant Agreement dated as of January 16, 2001. Incorporated herein by reference to Exhibit 4.14 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
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 1992 Incentive Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.1 to Chesapeake's registration statement on Form S-4 (No. 33-93718).
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.

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Exhibit Number	Description
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.
10.1.15†*	—Chesapeake Energy Corporation 401(k) Make-Up Plan.
10.1.16†*	—Chesapeake Energy Corporation Deferred Compensation Plan
10.2.1†	—Second Amended and Restated Employment Agreement dated as of July 1, 2001, between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 4.7 to Chesapeake’s quarterly report on Form 10-Q for the quarter ended September 30, 2001.
10.2.2†	—Second Amended and Restated Employment Agreement dated as of July 1, 2001, between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 4.8 to Chesapeake’s quarterly report on Form 10-Q for the quarter ended September 30, 2001.
10.2.3†	—Amended and Restated Employment Agreement dated as of August 1, 2000 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Chesapeake’s registration statement on Form S-1 (No. 333-45872).
10.2.8†	—Employment Agreement dated as of July 1, 2000 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 June 30, 2000.
10.2.9†	—Employment Agreement dated as of July 1, 2000 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 June 30, 2000.
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.

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Exhibit Number	Description
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
23.1*	—Consent of PricewaterhouseCoopers LLP
23.2*	—Consent of Williamson Petroleum Consultants, Inc.
23.3*	—Consent of Ryder Scott Company L.P.
23.4*	—Consent of Lee Keeling and Associates, Inc.
23.5*	—Consent of Netherland, Sewell and Associates, Inc.
99.1*	—Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.2*	—Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification 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.

PURCHASE AND SALE AGREEMENT

By And Between

EL PASO PRODUCTION COMPANY

and

NORIC, L.P.

AS SELLER

and

CHESAPEAKE EP CORPORATION

AS BUYER

PROPERTY PACKAGE

Mid Continent / Weatherford / Oklahoma & Texas

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PURCHASE AND SALE AGREEMENT

This Purchase and Sale Agreement (this "Agreement") is entered into this 21st day of February, 2003, by and between EL PASO PRODUCTION COMPANY, a Delaware corporation and NORIC, L.P. a Delaware limited partnership (collectively "Seller") and CHESAPEAKE EP CORPORATION, an Oklahoma corporation, ("Buyer"). Buyer and Seller are collectively referred to herein as the "Parties" and sometimes individually referred to as a "Party."

RECITALS:

A. Seller desires to sell to Buyer certain oil, gas and mineral properties and other assets on the terms and conditions set forth in this Agreement.

B. Buyer desires to purchase from Seller such assets on the terms and conditions set forth in this Agreement.

WITNESSETH:

In consideration of the mutual agreements contained in this Agreement, Buyer and Seller agree as follows:

1. SALE AND PURCHASE OF THE ASSETS.

1.1 Acquired Assets. Subject to the terms and conditions of this Agreement, Seller agrees to sell, convey and deliver to Buyer and Buyer agrees to purchase and acquire from Seller all of Seller's or Seller's affiliate's right, title and interest in and to the following (collectively, the "Assets"):

(A) (i) All of the mineral interests, leasehold interests, royalty interests, overriding royalty interests, payments out of production, reversionary rights, and contractual rights to production in and to the leases, subleases, assignments and other instruments described in Exhibit 1.1(A)-1 (collectively, "Leases"); (ii) those wells described in Exhibit 1.1(A)-2 (the "Wells"); (iii) all easements, rights of way, and other rights, privileges, benefits and powers with respect to the use and occupation of the surface of, and the subsurface depths under, the land covered by the Leases; (iv) any pooled or unitized acreage located in whole or in part within each Lease, including all Oil and Gas production from the pool or unit allocated to any such Lease and all interests in any wells within the unit or pool associated with such Lease (the "Units"), regardless of whether such unit or pool production comes from wells located within or without the Leases;

(B) All of the oil and gas and associated hydrocarbons ("Oil and Gas") in and under or otherwise attributable that are covered by the Leases and the Units or produced from the Wells;

(C) To the extent assignable and applicable to the Assets, all licenses, servitudes, gas purchase and sale contracts (including interests and rights, if any, with respect to any prepayments, take-or-pay, buydown and buyout agreements) to the extent that the same pertain or relate to periods after the Effective Time, as hereinafter defined, crude purchase and sale agreements, farmin agreements, farmout agreements, bottom hole agreements, acreage contribution agreements, operating agreements, unit agreements, processing agreements, options, leases of equipment or facilities, joint venture agreements, pooling agreements, transportation agreements, gathering and compression agreements, rights-of-way and other contracts, agreements and rights, which are owned by Seller, in whole or in part, and are appurtenant to the Leases including but not limited to those described on Exhibit 1.1(C) (collectively, the "Contracts");

(D) All of the real, personal and mixed property and facilities located in or on the Leases used solely in the operation thereof which are owned by Seller, in whole or in part, including, without limitation, well equipment, vehicles, field offices, casing; tanks; crude oil, natural gas, condensate or products in storage severed after the Effective Time; tubing; compressors; pumps; motors; fixtures; machinery and other equipment; pipelines; field processing equipment; inventory and all other improvements used in the operation thereof described on Exhibit 1.1(D) (the "Related Assets");

(E) To the extent assignable, all governmental permits, licenses and authorizations, as well as any applications for the same, related to the Leases or the use thereof; and

(F) All of Seller's files, records and data relating to the items described in subsections (A), (B), (C), (D) and (E) above, including, without limitation, title records (title curative documents); surveys, maps and drawings; contracts; correspondence; geological records and information; production records, electric logs, core data, pressure data, decline curves, graphical production curves and all related matters and construction documents except (i) to the extent the transfer, delivery or copying of such records may be restricted by contract with a third party; (ii) all documents and instruments of Seller that may be protected by the attorney-client privilege; (iii) all accounting and Tax files, books, records, Tax returns and Tax work papers related to such items; and (iv) all of Seller's proprietary geophysical and seismic records, data and information (for which Seller agrees to grant Buyer a license on Seller's license form to the extent, in Seller's reasonable opinion, it is entitled to provide such a license without cost to Seller or liability to a third party) (collectively, the "Records").

1.2 Excluded Assets. Notwithstanding the foregoing, the Assets shall not include, and there is excepted, reserved and excluded from the purchase and sale contemplated herein those items listed in Exhibit 1.2 (the "Excluded Assets").

1.3 Assumed Liabilities. On the Closing Date, Buyer shall assume and agree to timely and fully pay, perform and otherwise discharge, without recourse to Seller or its affiliates, all of the liabilities and obligations of Seller and its affiliates, successors, assigns or representatives, direct or indirect, known or unknown, asserted or unasserted, absolute or contingent, accrued or unaccrued, which relate, directly or indirectly, to the Assets, whether such liabilities and obligations accrue before, on or after the Effective Time (collectively, the "Assumed Liabilities"). Notwithstanding the foregoing, Assumed Liabilities shall not include, and there is excepted, reserved and excluded from such liabilities assumed by Buyer, the liabilities and obligations for which Seller indemnifies Buyer against pursuant to Section 14.1 and interest and penalties on suspense funds under Section 4.5, liabilities arising out of employment issues related to Seller's employees, liabilities arising out of Seller's shareholder matters, any hedging obligations burdening the production from the Assets and any matters subject to post-closing adjustments under Section 4.

2. PURCHASE PRICE.

2.1 Purchase Price. The purchase price for the Assets is Five Hundred Million Dollars ($500,000,000.00) (the "Purchase Price"), subject to the adjustments provided for in this Agreement. The Purchase Price shall be paid as follows: Buyer shall pay to Seller a deposit ("Deposit") of five percent (5%) of the Purchase Price upon execution of this Agreement and shall pay the balance of the Purchase Price at Closing. The Deposit shall be refundable to Buyer in the event the contemplated sale of the Assets fails to close unless the failure to close is due to the default of Buyer.

2.2 Adjustments to the Purchase Price. For purposes of determining the Post-Closing Adjustments provided for in Section 4, appropriate adjustments to the Purchase Price shall be made as follows:

(A) The Purchase Price shall be adjusted upward by:

(i) any amount determined to be due Seller pursuant to Section 4.2;

(ii) Taxes paid by Seller attributable to the period after April 1, 2003 ("Effective Time") which are apportioned to Buyer pursuant to Section 4.3.

(iii) an amount equal to the costs, expenses and other expenditures (whether capitalized or expensed) paid by Seller in accordance with this Agreement that are attributable to the Assets for the period from 9:00 a.m. (Central Time) on April 1, 2003 (the "Effective Time") to the Closing Date;

(iv) all amounts owed to Seller by third parties with respect to any Imbalances existing at the Effective Time, such amounts to be determined for Imbalances by multiplying the Imbalance volume by $1.50 per mcf for Well Imbalances and $3.00 per mcf for pipeline imbalances;

(v) an amount equal to the amount of proceeds derived from the sale of Oil and Gas, actually received by Buyer and directly attributable to the Wells which are, in accordance with generally accepted accounting procedures, attributable to the period of time prior to the Effective Time.

(vi) interest on the Base Purchase Price in an amount equal to the lesser of (A) the prime rate of Chase Manhattan Bank plus two percent (2%) or (B) the maximum legal rate (the "Interest"), with such Interest accruing from the scheduled Closing Date set forth in Section 3.1 until the actual Closing Date to the extent that the conditions set forth in Article 11 have been satisfied or waived and Buyer refuses or otherwise fails to proceed to Closing on or before the scheduled Closing Date set forth in Section 3.1, other than as a result of Seller's breach of this Agreement; and

(vii) any other amount agreed upon in writing by Seller and Buyer.

(B) The Purchase Price shall be adjusted downward by:

(i) an amount equal to the amount of proceeds derived from the sale of Oil and Gas, actually received by Seller and directly attributable to the Wells which are, in accordance with generally accepted accounting procedures, attributable to the period of time from and after the Effective Time;

(ii) an amount equal to all expenditures, liabilities and costs (whether capitalized or expensed) relating to the Assets (other than Taxes related to the Assets) that are unpaid as of the Closing Date and assessed for or attributable to periods of time prior to the Effective Time;

(iii) all amounts owed by Seller to third parties with respect to any Imbalances existing as of the Effective Time, such amounts to be determined for Imbalances by multiplying the Imbalance volume by $1.50 per mcf for well imbalances and $3.00 per mcf for pipeline imbalances;

(iv) Exercised Preferential Rights as determined pursuant to Section 9.3 and Casualty Losses as determined pursuant to Section 15.1; and

(v) Taxes attributable to the period beginning on the Closing Date and ending on the Effective Time which are apportioned to Seller pursuant to Section 4.3.

(vi) any other amount agreed upon in writing by Seller and Buyer.

The term "Imbalance" means any Oil and Gas production and pipeline imbalance existing as of the Effective Time with respect to any of the Assets, together with any related rights or obligations as to future cash and/or gas or product balancing, as a result of, in the case of production imbalances, Seller having taken and sold for Seller's account cumulative production which is greater or less than Seller's share in cumulative production.

(C) Seller shall have the right to collect any receivable, refund or other amounts associated with periods prior to the Effective Time to the extent Seller has not received credit for such amounts from Buyer. To the extent that Buyer collects any such receivable, refund or other amounts, then Buyer shall promptly remit any such amounts to Seller.

2.3 Allocation. The Purchase Price shall be allocated to the Assets as set forth in Exhibit 2.3. Seller and Buyer covenant and agree that the values allocated to various portions of the Assets, which are set forth on Exhibit 2.3 (singularly with respect to each item, the "Allocated Value" and collectively, the "Allocated Values"), shall be binding on Seller and Buyer and shall be used for the purposes of adjusting the Purchase Price pursuant to Sections 9.3 (relating to Preferential Rights) and 15.1 (relating to Casualty Losses) and is not intended as a measure of value for any other purpose.

2.4 Allocation For Tax Purposes. For the purpose of making the requisite filings under Section 1060 of Internal Revenue Code of 1986, as amended, (the "Code") and the regulations thereunder, Seller and Buyer shall make a good faith effort, within one hundred-twenty (120) days following the Closing Date, to agree to allocate, the Purchase Price (as adjusted by Section 2.2) and all obligations assumed by Buyer pursuant to Section 1.3 among the Assets. Seller and Buyer each agree to report the federal, state and local income and other Tax consequences of the transactions contemplated herein, and in particular to report the information required by Section 1060(b) of the Code, and to jointly prepare Form 8594 (Asset Acquisition Statement under Section 1060) in a manner consistent with such allocation and shall not take any position inconsistent therewith upon examination of any Tax return, in any refund claim, in any litigation, investigation or otherwise. Seller and Buyer agree that each shall furnish the other a copy of Form 8594 (Asset Acquisition Statement under Section 1060) proposed to be filed with the Internal Revenue Service by such Party or any affiliate thereof within ten (10) days prior to the filing of such form with the Internal Revenue Service.

3. CLOSING.

3.1 Closing. Subject to the conditions precedent set forth in Articles 11 and 12 and any termination pursuant to Article 13 or Section 15.1, the sale and purchase of the Assets ("Closing") shall be held on the later of March 12, 2003 or the first business day after Seller's receipt of releases of all mortgage and financing instruments burdening the Assets, provided that if such releases are not obtained by April 30, 2003, the Parties shall on that date close as to all Assets not burdened by such instruments and delay closing on the Assets burdened by such instruments for a time to be mutually agreed upon ("Closing Date"). The Closing will take place at the offices of Seller at Nine Greenway Plaza, Houston, Texas 77046.

3.2 Delivery by Seller. At Closing, Seller shall deliver to Buyer:

(A) An Assignment and Bill of Sale or other appropriate conveyances substantially in the forms attached hereto as Exhibit 3.2(A), effecting the sale, transfer, conveyance and assignment of the Assets; and

(B) a Certification of Non-Foreign Status substantially in the form attached hereto as Exhibit 3.2(B)i and Exhibit 3.2(B)ii.

(C) Executed Letters in lieu of Transfer Orders.

(D) Change of Operator Forms required to be filed with the Oklahoma Corporation Commission or Texas Railroad Commission.

3.3 Delivery by Buyer. At Closing, Buyer shall deliver to Seller per Seller's wiring instructions with separate payments to Noric and to El Paso Production Company (based upon the valuations set out on Exhibit 2.3) or Seller's designee the Purchase Price less the Deposit by wire transfer in immediately available funds.

3.4 Further Cooperation. At the Closing and thereafter as may be necessary, Seller and Buyer shall execute and deliver such other instruments and documents and take such other actions as may be reasonably necessary to evidence and effectuate the transactions contemplated by this Agreement.

4. ACCOUNTING ADJUSTMENTS.

4.1 Adjustments shall be made to the Purchase Price in accordance with Section 2.2.

4.2 Strapping and Gauging. Seller has caused the Oil and Gas in the storage facilities located on, or utilized in connection with, the Leases to be measured, gauged or strapped as of the Effective Time. Seller has caused the production meter charts (or if such do not exist, the sales meter charts) on the pipelines transporting Oil and Gas from the Leases to be read as of such time. The Oil and Gas in such storage facilities above the pipeline connection or through the meters on the pipelines prior to the Effective Time shall belong to Seller, and the Oil and Gas placed in such storage facilities from and after the Effective Time and production upstream of the aforesaid meters shall belong to Buyer and become part of the Assets.

4.3 Tax Matters.

4.3(A) Apportionment of Tax Liability. For purposes of this Agreement, "Tax" or "Taxes" shall mean all ad valorem, property, production, excise, net proceeds, severance and all other taxes and similar obligations assessed against the Assets or based upon or measured by the ownership of the Assets or the production of hydrocarbons or the receipt of proceeds therefrom, other than income taxes. All Taxes based on or attributable to the ownership of, or based on production of hydrocarbons shall be deemed attributable to the period during which such Taxes are assessed. With respect to the Assets, all Taxes shall be prorated between Buyer and Seller as of the Effective Time for all taxable periods that include the Effective Time. Accordingly, for the purpose of apportioning the liability for Taxes and the resulting Purchase Price adjustment pursuant to Section 2, (i) Buyer shall be responsible for all Taxes related to the Assets that are attributable to the period of time after the Effective Time and (ii) Seller shall be responsible for all Taxes related to the Assets that are attributable to the period of time on or before the Effective Time.

4.3(B) Apportionment of Taxes/Purchase Price Adjustment. Based on the best current information available as of Post-Closing, the pro-ration of Taxes shall be made between the Parties as an adjustment to the Purchase Price pursuant to Section 2 and that pro-ration shall be deemed to be a final settlement between the Parties with respect to Taxes. Accordingly, after Post-Closing.

4.3(C) Tax Reports and Returns. For the tax period in which the Effective Time occurs, Seller agrees to immediately forward to Buyer any such tax reports and returns received by Seller after Closing and provide Buyer with appropriate information which is necessary for Buyer to file any required tax reports and returns related to the Assets. Buyer agrees to file all tax returns and reports applicable to the Assets that are required to be filed after the Closing, and pay all required Taxes payable with respect to the Assets.

4.3(D) Sales Taxes. Buyer shall be liable for and shall indemnify Seller for any sales and use taxes, conveyance, transfer and recording fees and real estate transfer stamps or taxes that may be imposed on any transfer of the Assets pursuant to this Agreement. If required by applicable law, Seller shall, in accordance with applicable law, calculate and remit any sales of similar taxes that are required to be paid as a result of the transfer of the Assets to Buyer and Buyer shall promptly reimburse Seller therefore. If Seller receives notice that any sales and/or use taxes are due, Seller shall promptly forward such notice to Buyer for handling.

4.4 Post-Closing Adjustments.

(A) Seller shall prepare and deliver to Buyer not later than July 11, 2003 a statement of adjustments to the Purchase Price (the "Post-Closing Adjustment Statement") which shall be based on the actual income and expenses attributable to the Assets. Seller or Buyer, as the case may be, shall be given access to and shall be entitled to review and audit the other Party's records pertaining to the computation of amounts claimed in such Post-Closing Adjustment Statement.

(B) On or before July 28, 2003, Buyer shall deliver to Seller a written statement describing in reasonable detail its objections (if any) to any amounts or items set forth on or omitted from the Post-Closing Adjustment Statement. If Buyer does not raise objections within such period, then the Post-Closing Adjustment Statement shall become final and binding upon the Parties at the end of such period.

(C) If Buyer raises objections, the Parties shall negotiate in good faith to resolve any such objections. If the Parties are unable to resolve any disputed item by August 15, 2003 any such disputed item shall be submitted to a nationally recognized independent accounting firm mutually agreeable to the Parties who shall be instructed to resolve such disputed item within thirty (30) days. The resolution of disputes by the accounting firm so selected shall be set forth in writing and shall be conclusive, binding and non-appealable upon the Parties and the Post-Closing Adjustment Statement shall become final and binding upon the Parties on the date of such resolution. The fees and expenses of such accounting firm shall be paid one-half by Buyer and one-half by Seller.

(D) After the Post Closing Adjustment Statement has become final and binding on the Parties, Seller or Buyer, as the case may be, shall pay to the other such sums as are due to settle accounts between the Parties due to final adjustments to the Purchase Price.

4.5 Suspended Funds. No later than June 30, 2003, Seller shall provide to Buyer a computer readable listing showing all proceeds from production attributable to the Leases which are currently held in suspense and shall transfer to Buyer all of those suspended proceeds without deducting any receivables, provided that Buyer agrees to use its best efforts to recoup and remit to Seller such receivables out of proceeds attributable to such accounts receivable, if any, after recoupment of amounts such party may owe Buyer. BUYER SHALL BE RESPONSIBLE FOR PROPER DISTRIBUTION OF ALL THE SUSPENDED PROCEEDS, TO THE EXTENT TURNED OVER TO IT BY SELLER, TO THE PARTIES LAWFULLY ENTITLED TO THEM AND ANY CLAIMS RELATED THERETO EXCEPT FOR ANY STATUTORY INTEREST AND PENALTIES DUE THEREON WHICH SHALL BE SELLER'S RESPONSIBILITY, AND BUYER HEREBY AGREES TO INDEMNIFY, DEFEND AND HOLD HARMLESS SELLER FROM AND AGAINST ANY AND ALL LOSSES AS DEFINED BELOW ARISING OUT OF OR RELATING TO THOSE SUSPENDED PROCEEDS.

4.6 Audit Adjustments. Seller retains all rights to adjustments resulting from any operating agreement and other audit claims asserted against third party operators on transactions occurring prior to the Effective Time (which includes Buyer, if applicable). Any credit received by Buyer pertaining to such an audit claim shall be paid to Seller within thirty (30) days after receipt.

4.7 Tax Refunds. Refunds of Taxes paid or payable with respect to or attributable to the Assets shall be promptly paid as follows (or to the extent payable but not paid due to offset against other Taxes shall be promptly paid by the Party receiving the benefit of the offset as follows): (i) to Seller if attributable to Taxes with respect to any Tax year or portion thereof ending on or before the Effective Time; and (ii) to Buyer if attributable to Taxes with respect to any Tax year or portion thereof beginning from and after the Effective Time.

4.8 Cooperation. Each Party covenants and agrees to promptly inform the other with respect to amounts owing under Sections 4.4, 4.6 and 4.7 hereof.

5. ACCESS TO ASSETS AND RECORDS.

5.1 General Access. Not later than March 3, 2003, Seller shall:

(A) Give Buyer and its representatives, employees, consultants, independent contractors, attorneys and other advisors reasonable access to the Leases (to the extent same are Seller operated) and other Assets during regular office hours to assist Buyer's preparation to assume operations;

(B) Make available to Buyer all other information with respect to the Assets as Buyer may from time to time reasonably request, unless Seller is prohibited therefrom by any agreement, contract, obligation or duty by which it is bound or by the necessity of any third party approval; provided that, if requested by Buyer, Seller shall use reasonable efforts to obtain the waiver of any such prohibition or the granting of any such approval.

5.2 Seller's Title.

(A) The documents to be executed and delivered by Seller to Buyer transferring the Assets to Buyer shall be substantially in the form set forth in Exhibit 3.2(A). Such documents shall provide that for a period of two (2) years after the Effective Time, Seller shall warrant and defend the Assets unto Buyer against every person lawfully claiming the Assets or any part thereof, by, through or under Seller, but not otherwise. However, all of Seller's interests in the Assets are to be sold AS IS AND WHERE IS AND WITHOUT WARRANTY OF MERCHANTABILITY, CONDITION OR FITNESS FOR A PARTICULAR PURPOSE, EITHER EXPRESS OR IMPLIED.

(B) Buyer acknowledges and agrees that Seller cannot and does not covenant or warrant that Buyer shall become successor operator of all or any portion of the Assets, since the Assets or portions thereof may be subject to unit, pooling, communization, operating or other agreements which control the appointment of a successor operator.

(C) After Closing, Seller shall use best efforts to cause its affiliates to provide documents necessary to vest title to the Assets into Buyer.

5.3 Encumbrances on Title to the Assets, Matters to which the Assets are Subject and Condition of the Assets.

(A) Title and Matters to which the Assets are Subject. As of the date of execution of this Agreement and as of Closing Buyer accepts the Assets and Seller's title to the Assets "as is where is", without examination or inspection and subject to any and all encumbrances on Seller's title, whether such encumbrances are or are not of public record. In addition, Seller accepts the Assets subject to any and all agreements to which the Assets may be subject including but not limited to the following:

(1) The terms and conditions of the Leases, including without limitation lessors' royalties, overriding royalties, net profits interests, carried interests, production payments, reversionary interests and similar burdens;

(2) The division orders and sales contracts;

(3) Preferential Rights and required third party consents;

(4) Materialman's, mechanic's, repairman's, employee's, contractor's, operator's

and other similar liens or charges arising in the ordinary course of business for obligations that are not delinquent or that will be paid and discharged in the ordinary course of business, or if delinquent, that are being contested in good faith by appropriate action of which Buyer is notified in writing before Closing;

(5) All rights to consent by, required notices to, filings with, or other actions by governmental entities in connection with the sale or conveyance of oil and gas leases or interests therein;

(6) Easements, rights-of-way, servitudes, permits, surface leases and other rights in respect of surface operations;

(7) Except for hedging contracts that burden production from the Assets, all operating agreements, unit agreements, unit operating agreements, pooling agreements and pooling designations, gas and crude oil sales and marketing agreements (including gathering, treating, processing, storage, transportation agreements) and all other agreements affecting the Assets whether or not they are of record in Seller's chain of title or are reflected or referenced in Seller's files;

(8) Conventional rights of reassignment prior to release or surrender requiring notice to the holders of the rights;

(9) All rights reserved to or vested in any governmental, statutory or public authority to control or regulate any of the Assets in any manner, and all applicable laws, rules and orders of governmental authority;

(10) All other liens, charges, encumbrances, contracts, agreements, instruments, obligations, defects and irregularities affecting the Assets;

Notwithstanding the foregoing, at and as of Closing, Seller's title shall be free and clear of mortgage and financing encumbrances and undisputed vendor liens.

(B) Environmental Condition of the Assets.

As of the date of execution of this Agreement and as of Closing Buyer accepts the Assets in their present environmental condition, "as is where is", without examination or inspection and subject to any and all adverse environmental conditions.

Buyer acknowledges that the Assets have been used for oil and gas drilling and production operations and possibly for the storage and disposal of waste materials or hazardous substances related to standard oil field operations. Physical changes in or under the Assets or adjacent lands may have occurred as a result of such uses. The

Assets also may contain buried pipelines and other equipment, whether or not of a similar nature, the locations of which may not now be known by Seller or be readily apparent by a physical inspection of the Assets. Buyer understands that Seller does not have the requisite information with which to determine the exact nature or condition of the Assets nor the effect any such use has had on the physical condition of the Assets. Pursuant to the Safe Water Drinking and Toxic Enforcement Act of 1986, Buyer is hereby notified and assumes the risk that detectable amounts of chemicals known to cause cancer, birth defects and other reproductive harm may be found in, on or around the Assets. Buyer shall assume the risk that the Assets may contain waste or contaminants and that adverse physical conditions, including the presence of waste or contaminants, may not have been revealed by Buyer's investigation, if any. All responsibility and liability related to disposal, spills, waste or contamination on or below the Assets shall be transferred from Seller to Buyer.

In addition, Buyer acknowledges that some oil field production equipment located on the Assets may contain asbestos and/or naturally occurring radioactive material ("NORM"). In this regard, Buyer expressly understands that NORM may affix or attach itself to inside of wells, materials and equipment as scale or in other forms, and that wells, materials and equipment located on the Assets described herein may contain NORM and that NORM-containing materials may be buried or have been otherwise disposed of on the Assets. Buyer also expressly understands that special procedures may be required for the removal and disposal of asbestos and NORM from the Assets where they may be found, and that Buyer assumes all liability when such activities are performed.

5.4 Buyer's Activities on the Assets and on Seller's Premises Until Closing.

Buyer waives and releases all claims against Seller, its parent and subsidiary companies, and each of their respective directors, officers, employees, agents and other representatives and their successor and assigns (collectively, the "Seller Group"), for injury to or death of persons, or damage to property, arising in any way from the exercise of rights granted to Buyer with respect to the Assets or the activities of Buyer or its employees, agents or contractors on the Assets or on Seller's premises. BUYER SHALL INDEMNIFY THE SELLER GROUP AGAINST AND HOLD EACH AND ALL OF SAID INDEMNITEES HARMLESS FROM ANY AND ALL LOSSES WHATSOEVER ARISING OUT OF (I) ANY AND ALL STATUTORY OR COMMON LAW LIENS OR OTHER ENCUMBRANCES FOR LABOR OR MATERIALS FURNISHED IN CONNECTION WITH SUCHACTIVITIES AS BUYER MAY CONDUCT WITH RESPECT TO THE ASSETS; AND (II) ANY INJURY TO OR DEATH OF PERSONS OR DAMAGE TO PROPERTY OCCURRING IN, ON OR ABOUT THE ASSETS AS A RESULT OF SUCH EXERCISE OR ACTIVITIES.

6. Section 6 has been intentionally deleted by the Parties.

7. REPRESENTATIONS AND WARRANTIES OF SELLER.

7.1 Seller's Representations and Warranties. Subject to the disclosures set forth in the Exhibits referred to in this Section 7, Seller represents and warrants (which representations and warranties shall not survive the Closing except as expressly provided in Section 14) as follows:

(A) Status of Incorporation. Seller is a corporation duly incorporated, validly existing and in good standing under the laws of the State of Delaware.

(B) Corporate Authority. Seller owns the Assets and has the requisite power and authority to enter into this Agreement, to carry out the transactions contemplated hereby, to transfer the Assets in the manner contemplated by this Agreement, and to undertake all of the obligations of Seller set forth in this Agreement.

(C) Validity of Obligations. This Agreement and any documents or instruments delivered by Seller at the Closing shall constitute legal, valid and binding obligations of Seller, enforceable in accordance with their terms.

(D) AFE's. With respect to the joint, unit or other operating agreements relating to the Assets, to Seller's knowledge, except as set forth in Exhibit 7.1(D), there are no material outstanding calls or payments under authorities for expenditures for payments relating to the Assets which exceed FiftyThousand Dollars ($50,000.00) (net to Seller's interest) and which are due or which Seller has committed to make which have not been made.

(E) Contractual Restrictions. Seller has not entered into any contracts for or received prepayments, take-or-pay arrangements, buydowns, buyouts for Oil and Gas, or storage of the same relating to the Assets which Buyer shall be obligated to honor and make deliveries of Oil and Gas or pay refunds of amounts previously paid under such contracts or arrangements.

(F) Litigation. Except as set forth in Exhibit 7.1(F), there is no suit or action pending, arising out of, or with respect to the ownership, operation or environmental condition of the Assets that would have an adverse affect upon the Assets and for which Buyer has not been indemnified by Seller in accordance with Section 14.

(G) Permits and Consents. To Seller's knowledge, with respect to the Assets Seller or Operator (i) has acquired all material permits, licenses, approvals and consents from appropriate governmental bodies, authorities and agencies to conduct operations on the Assets in compliance with applicable laws, rules, regulations, ordinances and orders; and (ii) is in material compliance with all such permits, licenses, approvals and consents and with applicable Environmental Laws.

(H) Broker's Fees. Seller shall retain the obligation or liability, contingent or otherwise, for brokers' or finders' fees in respect of the matters provided for in this Agreement and Buyer shall have no responsibility therefor.

(I) Taxes. Except as set forth in Exhibit 7.1(I), (i) Seller has filed (with respect to the Assets) all material Tax returns that are due, (ii) all Taxes (with respect to the Assets) shown to be due on such returns have been paid, and (iii) there is no material dispute or claim concerning any Tax liability of the Seller (with respect to the Assets) claimed or raised by any Tax authority in writing. For purposes of this Agreement, the term "Tax" or "Taxes" means any federal, state, local or tribal, income, gross receipts, license, payroll, employment, excise, severance, stamp, occupation, premium, windfall profits, environmental (including taxes under Section 59A of the Code), custom duties, capital stock, franchise, profits, withholding, social security (or similar excises), unemployment, disability, real property, personal property, sales, use, transfer, registration, value added, alternative or add-on minimum, estimated, or other tax of any kind whatsoever, including any interest, penalty or addition thereto, whether disputed or not.

(J) Seller shall use best efforts to obtain releases of all mortgage and financing instruments burdening the Assets during the period prior to April 30, 2003.

7.2 Scope of Representations of Seller.

(A) Information About the Assets. Except as expressly set forth in this Agreement, Seller disclaims all liability and responsibility for any representation, warranty, statements or communications (orally or in writing) to Buyer, including any information contained in any opinion, information or advice that may have been provided to Buyer by any employee, officer, director, agent, consultant, engineer or engineering firm, trustee, representative, investment banker, financial advisor, partner, member, beneficiary, stockholder or contractor of Seller wherever and however made, including those made in any data room or internet site and any supplements or amendments thereto or during any negotiations with respect to this Agreement or any confidentiality agreement previously executed by the Parties with respect to the Asset. EXCEPT AS SET FORTH IN THIS ARTICLE 7 OF THIS AGREEMENT, SELLER MAKES NO WARRANTY OR REPRESENTATION, EXPRESS, STATUTORY OR IMPLIED, AS TO (i) THE ACCURACY, COMPLETENESS OR MATERIALITY OF ANY DATA, INFORMATION OR RECORDS FURNISHED TO BUYER IN CONNECTION WITH THE ASSETS OR OTHERWISE CONSTITUTING A PORTION OF THE ASSETS; (ii) THE PRESENCE, QUALITY AND QUANTITY OF HYDROCARBON RESERVES (IF ANY) ATTRIBUTABLE TO THE ASSETS, INCLUDING WITHOUT LIMITATION SEISMIC DATA AND SELLER'S INTERPRETATION AND OTHER ANALYSIS THEREOF; (iii) THE ABILITY OF THE ASSETS TO PRODUCE HYDROCARBONS, INCLUDING WITHOUT LIMITATION PRODUCTION RATES, DECLINE RATES AND RECOMPLETION OPPORTUNITIES; (iv) IMBALANCE OR PAYOUT ACCOUNT INFORMATION, ALLOWABLES, OR OTHER REGULATORY MATTERS; (v) THE PRESENT OR FUTURE VALUE OF THE ANTICIPATED INCOME, COSTS OR PROFITS, IF ANY, TO BE DERIVED FROM THE ASSETS; (vi) THE ENVIRONMENTAL CONDITION OF THE ASSETS; (vii) ANY PROJECTIONS AS TO EVENTS THAT COULD OR

COULD NOT OCCUR; (viii) THE TAX ATTRIBUTES OF ANY ASSET; (ix) ANY OTHER MATTERS CONTAINED IN OR OMITTED FROM ANY INFORMATION OR MATERIAL FURNISHED TO BUYER BY SELLER OR OTHERWISE CONSTITUTING A PORTION OF THE ASSETS; AND (x) THE COMPLETENESS OR ACCURACY OF THE INFORMATION CONTAINED IN ANY EXHIBIT HERETO. ANY DATA, INFORMATION OR OTHER RECORDS FURNISHED BY SELLER ARE PROVIDED TO BUYER AS A CONVENIENCE AND BUYER'S RELIANCE ON OR USE OF THE SAME IS AT BUYER'S SOLE RISK.

(B) Independent Investigation. Buyer has, or by Closing will have, made its own independent investigation, analysis and evaluation of the transactions contemplated by this Agreement (including Buyer's own estimate and appraisal of the extent and value of Seller's Oil and Gas reserves attributable to the Assets and an independent assessment and appraisal of the environmental risks and liabilities associated with the acquisition of the Assets). Buyer has had access to all information necessary to perform its investigation and has not relied on any representations by Seller other than those expressly set forth in this Agreement.

(C) Waiver of Deceptive Trade Practices Acts. BUYER WAIVES ITS RIGHTS UNDER THE DECEPTIVE TRADE PRACTICES ACT SECTION 17.41 et seq., TEXAS BUSINESS & COMMERCE CODE, A LAW THAT GIVES CONSUMERS SPECIAL RIGHTS, AND UNDER SIMILAR STATUTES ADOPTED IN OTHER STATES, TO THE EXTENT THEY HAVE APPLICABILITY TO THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT. AFTER CONSULTATION WITH AN ATTORNEY OF ITS SELECTION, BUYER CONSENTS TO THIS WAIVER.

8. REPRESENTATIONS AND WARRANTIES OF BUYER.

8.1 Buyer's Representations and Warranties. Buyer represents and warrants (which representations and warranties shall survive the Closing) as follows:

(A) Status of Incorporation. Buyer is a corporation duly incorporated, validly existing and in good standing under the laws of the State of Oklahoma.

(B) Corporate Authority. Buyer has the corporate power and authority to enter into this Agreement, to carry out the transactions contemplated hereby and to undertake all of the obligations of Buyer set out in this Agreement.

(C) Validity of Obligations. The execution, delivery and performance of this Agreement and the performance of the transactions contemplated by this Agreement will not in any respect violate, nor be in conflict with, any provision of Buyer's charter, by-laws or other governing documents, or any agreement or instrument to which Buyer is a party or is bound, or any judgment, decree, order, statute, rule or regulation applicable to Buyer (subject to governmental consents and approvals customarily obtained after the Closing). This Agreement constitutes legal, valid and binding obligations of Buyer, enforceable in accordance with its terms.

(D) Qualification and Bonding. Buyer is in compliance with the bonding and liability insurance requirements in accordance with all applicable state or federal laws or regulations and that it is and henceforth will continue to be qualified to own any federal, Indian or state oil and gas leases that constitute part of the Assets.

(E) Non-Security Acquisition. Buyer intends to acquire the Assets for its own benefit and account and is not acquiring said Assets with the intent of distributing fractional undivided interests thereof such as would be subject to regulation by federal or state securities laws, and that if, in the future, it should sell, transfer or otherwise dispose of said Assets or fractional undivided interests therein, it will do so in compliance with any applicable federal and state securities laws.

(F) Evaluation. Buyer represents that by reason of Buyer's knowledge and experience in the evaluation, acquisition and operation of oil and gas properties, Buyer has evaluated the merits and risks of purchasing the Assets from Seller and has formed an opinion based solely upon Buyer's knowledge and experience and not upon any representations or warranties by Seller.

(G) Financing. Buyer has sufficient cash, available lines of credit or other sources of immediately available funds to enable it to pay the Purchase Price to Seller at the Closing.

(H) Broker's Fees. Buyer has incurred no obligation or liability, contingent or otherwise, for brokers' or finders' fees in respect of the matters provided for in this Agreement, and, if any such obligation or liability exists, it shall remain an obligation of Buyer, and Seller shall have no responsibility therefor.

(I) No Knowledge of Sellers' Breach. Buyer has no knowledge of any breach by Seller of any representation or warranty of Seller, or of any other fact, event, condition or circumstance that would excuse Buyer from the timely performance of its obligations hereunder.

9. CERTAIN AGREEMENTS OF SELLER. Seller agrees and covenants that, unless Buyer shall have otherwise agreed in writing, the following provisions shall apply:

9.1 Maintenance of Assets. From the date of this Agreement until Closing, Seller agrees that, for those Wells which Seller operates, it shall:

(A) Administer and operate the Wells in accordance with the applicable operating agreements.

(B) Not introduce any new methods of management, operation or accounting with respect to any or all of the Assets.

(C) Use commercially reasonable efforts to maintain and keep the Assets in full force and effect; and fulfill all contractual or other covenants, obligations and conditions imposed upon Seller with respect to the Assets, including, but not limited to, payment of royalties, delay rentals, shut-in gas royalties and any and all other required payments.

(D) Except to the extent necessary or advisable to avoid forfeiture or penalties, not enter into agreements to drill new wells or to rework, plug back, deepen, plug or abandon any Well, nor commence any drilling, reworking or completing or other operations on the Leases which requires expenditures exceeding Fifty Thousand Dollars ($50,000.00) (net to Seller's interest) for each operation (except for emergency operations and operations required under presently existing contractual obligations) without obtaining the prior written consent of Buyer (which consent shall not be unreasonably withheld, delayed or conditioned); provided that the terms of this paragraph (D) shall not apply to any expenditures of Seller which will not be charged to Buyer.

(E) Not voluntarily relinquish its position as operator to anyone other than Buyer with respect to any of the Wells or voluntarily abandon any of the Wells other than as required pursuant to the terms of a Lease or by regulation.

(F) Not, without the prior written consent of Buyer (which consent shall not be unreasonably withheld, delayed or conditioned), (i) enter into any agreement or arrangement transferring, selling or encumbering any of the Assets (other than in the ordinary course of business, including ordinary course sales of production, inventory or salvage or with respect to any Assets with a value less than Fifty Thousand Dollars ($50,000) or pursuant to any agreements existing on the date hereof); (ii) grant any preferential or other right to purchase or agree to require the consent of any party not otherwise required to consent to the transfer and assignment of the Assets to Buyer; (iii) enter into any new sales contracts or supply contracts which cannot be cancelled upon sixty (60) days prior notice; or (iv) incur or agree to incur any contractual obligation or liability (absolute or contingent) with respect to the Assets except as otherwise provided herein (including ordinary course sales of production, inventory or salvage or with respect to any Assets with a value less than Fifty Thousand ($50,000) or pursuant to any disclosed AFE's covering the Assets)

(G) To the extent known to Seller, provide Buyer with written notice of (i) any claims, demands, suits or actions made against Seller which materially affect the Assets; or (ii) any proposal from a third party to engage in any material transaction (e.g., a farmout) with respect to the Assets.

(H) Continue to market free of charge Buyer's gas produced from the Assets for the month of April 2003 in a manner not materially inconsistent with past practices provided that: 1) Buyer shall defend, hold harmless and indemnify Seller, its affiliated companies and its and their directors, officers, employees, agents and representatives from and against all cost and liability arising out of the marketing of said gas, save and except for Seller's obligation to pay Buyer the proceeds from such gas sales in a timely manner; and 2) Seller shall not be required to provide any collateral or security in marketing Buyer's gas.

(I) Consult with Seller's designated representative prior to taking any regulatory action to the extent it is practical to do so under the circumstances.

9.2 Consents. Seller shall exercise reasonable commercial efforts to obtain all such permissions, approvals and consents by governmental authorities and others which are reasonably obtainable by Closing and are required to vest title to the Assets in Buyer or as may be otherwise reasonably requested by Buyer. Seller will execute all necessary or appropriate transfer orders (or letters in lieu thereof) designating Buyer as the appropriate party for payment effective as of the Effective Time.

9.3 Preferential Rights.

(A) Seller agrees that it will (i) use reasonable efforts, consistent with industry practices in transactions of this type, to identify all preferential rights to purchase ("Preferential Rights") applicable to the transaction contemplated hereby, and the names and addresses of such parties holding the same, and (ii) request, from the parties so identified (and in accordance with the documents creating such rights), execution of waivers of Preferential Rights.

(B) If the holder of a Preferential Right exercises such right, Seller shall tender to such party the required interest in the affected Asset at a price equal to the Allocated Value (reduced appropriately, as determined by mutual agreement of Buyer and Seller, if less than the entire Asset must be tendered), and to the extent that such Preferential Right is exercised and such interest in such Asset is actually sold to the party so exercising such right, such interest in the Asset will be deemed an Excluded Asset and shall be excluded from the transaction contemplated hereby and the Purchase Price will be adjusted downward by the amount actually paid to Seller by the party exercising the Preferential Right.

(C) If, on the Closing Date, the holder of a Preferential Right has not indicated whether or not it will exercise such Preferential Right and the time period within which the holder of the Preferential Right must exercise its right has not lapsed, then the Parties shall proceed with Closing on those Assets affected by the Preferential Right and Buyer shall assume the responsibility for conveying the Assets to the holder of the Preferential Right should the holder timely exercise its Preferential Right. BUYER AGREES TO INDEMNIFY, DEFEND AND HOLD HARMLESS SELLER FROM AND AGAINST ANY AND ALL LOSSES ARISING OUT OF OR RELATING TO BUYER'S FAILURE TO COMPLY WITH THE TERMS OF SUCH PREFERENTIAL RIGHTS.

9.4 Hart-Scott-Rodino. The parties agree that this Agreement and the subject transaction do not require filings or approvals under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the "HSR Act") and the rules and regulations of the Federal Trade Commission thereunder.

9.5 Records and Contracts. Seller shall have the right to make and retain copies of the Records and Contracts as Seller may desire prior to the delivery of the Records and Contracts to Buyer. Buyer, for a period of five (5) years after the Closing Date, shall make available to Seller (at the location of such Records and Contracts in Buyer's organization) access to such Records and Contracts as Buyer may have in its possession (or to which it may have access) upon written request of Seller, during normal business hours; provided, however, that Buyer shall not be liable to Seller for the loss of any Records or Contracts by reason of clerical error or inadvertent loss or destruction of Records or Contracts. Seller, for a period of five (5) years after the Closing Date, shall make available to Buyer (at the location of such records in Seller's organization) access to records described in Section 1.1(F)(iii) (the "Excluded Records") as Seller may have in its possession (or to which it may have access) upon written request of Buyer, during normal business hours; provided, however, that Seller shall not be liable to Buyer for the loss of any Excluded Records by reason of clerical error or inadvertent loss or destruction of Excluded Records.

10. CERTAIN AGREEMENTS OF BUYER. Buyer agrees and covenants that unless Seller shall have consented otherwise in writing, the following provisions shall apply:

10.1 Plugging Obligation. Buyer shall perform and assume all liability for the necessary and proper plugging and abandonment of all Wells.

10.2 Plugging Bond. Buyer shall post, prior to Closing, the necessary bonds or letters of credit as required by the state in which the Leases are located for the plugging of all Wells, and provide Seller with a copy of same, and provide proof satisfactory to Seller that the applicable state has accepted such bonds or letters of credit as sufficient assurance to cover the plugging of all Wells and related matters. Further, Buyer shall provide to Seller copies of the approval by any applicable regulatory agencies concerning change of operatorship of the Wells.

10.3 Seller's Logos. Commencing no later than thirty (30) days after Closing, Buyer shall promptly cover or cause to be covered by decals or new signage any names and marks used by Seller, and all variations and derivatives thereof and logos relating thereto, from the Assets and shall not thereafter make any use whatsoever of such names, marks and logos.

10.4 Like-Kind Exchanges. Buyer shall cooperate fully, as and to the extent reasonably requested by Seller, in connection with the transactions contemplated herein to make such modifications as may be necessary to qualify such transactions, in whole or in part, as a "like-kind" exchange pursuant to Section 1031 of the Code.

11. CONDITIONS PRECEDENT TO OBLIGATIONS OF BUYER. All obligations of Buyer under this Agreement are, at Buyer's election, subject to the fulfillment, prior to or at the Closing, of each of the following conditions:

11.1 No Litigation. At the Closing, no suit, action or other proceeding shall be pending before any court or governmental agency which attempts to prevent the occurrence of the transactions contemplated by this Agreement.

11.2 Representations and Warranties. All representations and warranties of Seller contained in this Agreement shall be true in all material aspects as of the Closing as if such representations and warranties were made as of the Closing Date (except for those representations or warranties that are expressly made only as of another specific date, which representations and warranties shall be true in all material respects as of such other date) and Seller shall have performed and satisfied in all material respects all covenants and fulfilled all conditions required by this Agreement to be performed and satisfied by Seller at or prior to the Closing.

12. CONDITIONS PRECEDENT TO THE OBLIGATIONS OF SELLER. All obligations of Seller under this Agreement are, at Seller's election, subject to the fulfillment, prior to or at the Closing, of each of the following conditions:

12.1 No Litigation. At the Closing, no suit, action or other proceeding shall be pending before any court or governmental agency which attempts to prevent the occurrence of the transactions contemplated by this Agreement.

12.2 Representations and Warranties. All representations and warranties of Buyer contained in this Agreement shall be true in all material aspects as of the Closing, as if such representations and warranties were made as of the Closing Date (except for those representations or warranties that are expressly made only as of another specific date, which representations and warranties shall be true in all material respects as of such other date) and Buyer shall have performed and satisfied in all material respects all covenants and fulfilled all conditions required by this Agreement to be performed and satisfied by Buyer at or prior to the Closing.

13. TERMINATION.

13.1 Causes of Termination. This Agreement and the transactions contemplated herein may be terminated:

(A) At any time by mutual consent of the Parties.

(B) By either Party if the Closing shall not have occurred by April 30, 2003, despite the good faith reasonable efforts of the Parties, and if the Party desiring to terminate is not in breach of this Agreement.

(C) By either Party in the event of a Casualty Loss pursuant to Section 15.1(B).

(D) By Buyer if, on the Closing Date, any of the conditions set forth in Article 11 hereof shall not have been satisfied or waived.

(E) By Seller if, on the Closing Date, any of the conditions set forth in Article 12 hereof shall not have been satisfied or waived.

13.2 Effect of Termination. In the event of the termination of this Agreement pursuant to the provisions of this Article 13 or elsewhere in this Agreement, this Agreement shall become void and have no further force and effect and, except for the indemnities provided for in Section 5.4, any breach of this Agreement prior to such termination and any continuing confidentiality requirement, neither Party shall have any further right, duty or liability to the other hereunder. Upon termination, Buyer agrees to use its best efforts to return to Seller or destroy, all materials, documents and copies thereof provided, obtained or discovered in the course of any due diligence investigations.

14. INDEMNIFICATION.

14.1 INDEMNIFICATION BY SELLER. UPON CLOSING, SELLER SHALL, TO THE FULLEST EXTENT PERMITTED BY LAW, RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS BUYER, ITS PARENT AND SUBSIDIARY COMPANIES, AND EACH OF THEIR RESPECTIVE DIRECTORS, OFFICERS, EMPLOYEES, AGENTS AND OTHER REPRESENTATIVES (THE "BUYER GROUP") FROM AND AGAINST THE FOLLOWING:

(A) MISREPRESENTATIONS. ALL CLAIMS, DEMANDS, LIABILITIES, JUDGMENTS, LOSSES AND REASONABLE COSTS, EXPENSES AND ATTORNEYS' FEES (INDIVIDUALLY A "LOSS" AND COLLECTIVELY, THE "LOSSES") ARISING FROM THE BREACH BY SELLER OF ANY REPRESENTATION OR WARRANTY SET FORTH IN THIS AGREEMENT THAT SURVIVES CLOSING;

(B) BREACH OF COVENANTS. ALL LOSSES ARISING FROM THE BREACH BY SELLER OF ANY COVENANT SET FORTH IN THIS AGREEMENT; AND

(C) OWNERSHIP AND OPERATION. THAT PORTION OF ALL LOSSES ATTRIBUTABLE TO PERIODS PRIOR TO CLOSING AND ARISING FROM SELLER'S OWNERSHIP AND OPERATION OF THE ASSETS ASSOCIATED WITH THE FOLLOWING MATTERS:

(i) DAMAGES TO PERSONS OR PROPERTY;

(ii) THE VIOLATION BY SELLER OF ANY LAW OR REGULATION OR THE TERMS OF ANY AGREEMENT BINDING UPON SELLER;

(iii) CLAIMS OF SELLER'S CO-OWNERS, PARTNERS, JOINT VENTURERS AND OTHER PARTICIPANTS IN THE WELLS AND OR ASSETS;

(iv) THE INCORRECT PAYMENT OF ROYALTIES UNDER THE LEASES.

(D) THAT PORTION OF ALL LOSSES ATTRIBUTABLE TO PERIODS PRIOR TO THE EFFECTIVE TIME RESULTING FROM (i) LITIGATION, or (ii) OR TAXES.

(E) Notwithstanding the above, the following limitations shall apply to Seller's indemnification obligations:

(i) Seller shall not be obligated to indemnify Buyer Group for any Loss unless Buyer has delivered a written notice of such Loss within the Survival Period (as defined below) applicable to such Loss. Any Loss for which Seller does not receive written notice before the end of the Survival Period shall be deemed to be an Assumed Liability.

(1) The "Survival Period" applicable to Losses shall mean:

(i) With regard to a breach of representations and warranties relating to Taxes, for a period ending ninety (90) days following the expiration of the statute of limitations applicable to the underlying Tax matter giving rise to that claim.

(ii) With regard to breach of representations and warranties made in Sections 7.1(D)[AFEs] for a period ending on May 7, 2003.

(iii) With regard to breach of representations and warranties made in Sections 7.1(F)[Litigation], 7.1(G)[Permits and Consents], 7.1(H)[Broker's Fees] and 7.1(E) [Contractual Restriction], a period ending eighteen months after Closing.

(iv) All other Representations and Warranties of Seller shall not survive Closing.

(2) With regard to a breach of covenants and matters covered by 14.1(D), an indefinite period following the Closing; and

(3) With regard to the matters covered by Section 14.1(C)(i) through (iii) for a period of eighteen months after Closing.

(4) With regard to the matters covered by Section 14.1(C)(iv) for a period not to exceed the earlier of four years after the Effective Time or the applicable statute of limitations.

(ii) The indemnification obligations of Seller pursuant to this Agreement shall be limited to actual Losses and shall not include incidental, consequential, indirect, punitive, or exemplary Losses or damages to the extent such types of Losses pertain to periods after the Effective Time;

(iii) Seller's aggregate liabilities and obligations under this Article 14 shall not exceed twenty percent (20%) of the Purchase Price;

(iv) Seller shall have no liability or obligation for any Losses, unless and until the aggregate Losses for which Buyer is entitled to recover under this Agreement excluding losses covered by Section 14.1(D) [Litigation for which this subsection (iv) shall not apply] exceeds two percent (2%) of the Base Purchase Price (the "Threshold Amount"); provided, however, once such amount exceeds the Threshold Amount, the Buyer Group will be entitled to recover all amounts to which they are entitled in excess of the Threshold Amount;

(v) Seller's indemnification obligations shall not cover any liabilities, duties and obligations relating to properly plugging and abandoning wells, removal of all pipelines, equipment, and platforms and related facilities now or hereafter located on the Assets, and cleaning up, restoring and Remediation of the Assets in accordance with the Environmental Laws and the relevant Leases, including but not limited to liabilities, duties and obligations (including but not limited to the payment of fines, penalties, monetary sanctions or other amounts payable for failure to comply with the requirements of applicable Environmental Laws) related to any violation of any Environmental Laws or the presence, disposal, release or threatened release of any hazardous substance or hazardous waste from the Assets into the atmosphere or into or upon land or any water course or body of water, including groundwater, whether or not attributable to Seller's activities or the activities of third parties;

(vi) Buyer acknowledges and agrees that the indemnification provisions in this Article 14 and the termination rights in Article 13 shall be the exclusive remedies of Buyer with respect to the transactions contemplated by this Agreement.

14.2 INDEMNIFICATION BY BUYER. UPON CLOSING, BUYER SHALL TO THE FULLEST EXTENT PERMITTED BY LAW, RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS SELLER GROUP FROM AND AGAINST THE FOLLOWING:

(A) MISREPRESENTATIONS. ALL LOSSES ARISING FROM THE BREACH BY BUYER OF ANY REPRESENTATION OR WARRANTY SET FORTH IN THIS AGREEMENT THAT SURVIVES CLOSING;

(B) BREACH OF COVENANTS. ALL LOSSES ARISING FROM THE BREACH BY BUYER OF ANY COVENANT SET FORTH IN THIS AGREEMENT;

(C) OWNERSHIP AND OPERATION. ALL LOSSES ARISING FROM THE ASSUMED LIABILITIES, AND THE OWNERSHIP OR OPERATION OF THE ASSETS BY BUYER FROM AND AFTER CLOSING.

(D) THAT PORTION OF ALL LOSSES ATTRIBUTABLE TO PERIODS AFTER THE EFFECTIVE TIME RESULTING FROM LITIGATION.

14.3 PHYSICAL INSPECTION. BUYER INDEMNIFIES AND AGREES TO RELEASE, DEFEND, INDEMNIFY AND HOLD HARMLESS THE SELLER GROUP FROM AND AGAINST ANY AND ALL LOSSES ARISING FROM BUYER'S INSPECTING AND OBSERVING THE ASSETS, INCLUDING (A) LOSSES FOR PERSONAL INJURIES TO OR DEATH OF EMPLOYEES OF THE BUYER, ITS CONTRACTORS, AGENTS, CONSULTANTS AND REPRESENTATIVES, AND DAMAGE TO THE PROPERTY OF BUYER OR OTHERS ACTING ON BEHALF OF BUYER; AND (B) LOSSES FOR PERSONAL INJURIES TO OR DEATH OF EMPLOYEES OF THE SELLER GROUP OR THIRD PARTIES, AND DAMAGE TO THE PROPERTY OF THE SELLER GROUP OR THIRD PARTIES. THE FOREGOING INDEMNITY INCLUDES, AND THE PARTIES INTEND IT TO INCLUDE, AN INDEMNIFICATION OF THE SELLER GROUP FROM AND AGAINST LOSSES ARISING OUT OF OR RESULTING, IN WHOLE OR PART, FROM THE CONDITION OF THE ASSETS OR THE SELLER GROUP'S SOLE, JOINT, COMPARATIVE, OR CONCURRENT NEGLIGENCE, STRICT LIABILITY OR FAULT.

14.4 Notification. As soon as reasonably practical after obtaining knowledge thereof, the indemnified Party shall notify the indemnifying Party of any claim or demand which the indemnified Party has determined has given or could give rise to a claim for indemnification under this Article 14. Such notice shall specify the agreement, representation or warranty with respect to which the claim is made, the facts giving rise to the claim and the alleged basis for the claim, and the amount (to the extent then determinable) of liability for which indemnity is asserted. In the event any action, suit or proceeding is brought with respect to which a Party may be liable under this Article 14, the defense of the action, suit or proceeding (including all settlement negotiations and arbitration, trial, appeal, or other proceeding) shall be at the discretion of and conducted by the indemnifying Party. If an indemnified Party shall settle any such action, suit or proceeding without the written consent of the indemnifying Party (which consent shall not be unreasonably withheld), the right of the indemnified Party to make any claim against the indemnifying Party on account of such settlement shall be deemed conclusively denied. An indemnified Party shall have the right to be represented by its own counsel at its own expense in any such action, suit or proceeding, and if an indemnified Party is named as the defendant in any action, suit or proceeding, it shall be entitled to have its own counsel and defend such action, suit or proceeding with respect to itself at its own expense. Subject to the foregoing provisions of this Article 14, neither Party shall, without the other Party's written consent, settle, compromise, confess judgment or permit judgment by default in any action, suit or proceeding if such action would create or attach any liability or obligation to the other Party. The Parties agree to make available to each other, and to their respective counsel and accountants, all information and documents reasonably available to them which relate to any action, suit or proceeding, and the Parties agree to render to each other such assistance as they may reasonably require of each other in order to ensure the proper and adequate defense of any such action, suit or proceeding.

15. MISCELLANEOUS.

15.1 Casualty Loss.

(A) An event of casualty means volcanic eruptions, acts of God, terrorist action, fire, explosion, earthquake, wind storm, flood, drought, condemnation, the exercise of any right of eminent domain, confiscation and seizure (a "Casualty"). A Casualty does not include depletion due to normal production and depreciation or failure of equipment or casing.

(B) If, prior to Closing, a Casualty occurs (or Casualties occur) which results in a reduction in the value of the Assets in excess of twenty-five percent (25%) of the Base Purchase Price ("Casualty Loss"), Buyer or Seller may elect to terminate this Agreement. If this Agreement is not so terminated, then this Agreement shall remain in full force and effect notwithstanding any such Casualty Loss, and, upon agreement of the Parties, (i) Seller may retain such Asset and such Asset shall be the subject of an adjustment to the Base Purchase Price in the same manner set forth in Section 5.5 hereof, or (ii) at the Closing, Seller shall pay to Buyer all sums paid to Seller by reason of such Casualty Loss; provided, however, that the Base Purchase Price shall not be adjusted by reason of such payment, and Seller shall assign, transfer and set over unto Buyer all of the right, title and interest of Seller in and to such Asset and any unpaid awards or other payments arising out of such Casualty Loss.

(C) For purposes of determining the diminution in value of an Asset as a result of a Casualty Loss, the Parties shall use the Allocations set out on Exhibit 2.3.

15.2 Confidentiality.

(A) Prior to Closing and until all matters relating to the Final Settlement Date including all adjustments to the Base Purchase Price are finalized between the parties, to the extent not already public, Buyer shall exercise all due diligence in safeguarding and maintaining secure all engineering, geological and geophysical data, seismic data, reports and maps, the results and findings of Buyer with regard to its due diligence associated with the Assets (including without limitation with regard to due diligence associated with environmental and title matters) and other data relating to the Assets (collectively, the "Confidential Information"). Buyer acknowledges that all Confidential Information shall be treated as confidential and shall not be disclosed to third parties without the prior written consent of Seller.

(B) In the event of termination of this Agreement for any reason, Buyer shall not use or knowingly permit others to use such Confidential Information in a manner detrimental to Seller, and will not disclose any such Confidential Information to any person, firm, corporation, association or other entity for any reason or purpose whatsoever, except to Seller or to a governmental agency pursuant to a valid subpoena or other order or pursuant to applicable governmental regulations, rules or statutes.

(C) The undertaking of confidentiality shall not diminish or take precedence over any separate confidentiality agreement between the Parties. Should this Agreement terminate, such separate confidentiality agreement shall remain in full force and effect.

15.3 Competition. Buyer acknowledges that Seller may presently own interests or have leads, prospects, information or ideas on properties or leaseholds adjacent to, adjoining or in the vicinity of the Assets. Seller shall not be prohibited in any way from competing with Buyer or pursuing any activity or business opportunity on property not being transferred to Buyer pursuant to this Agreement.

15.4 Notice. Any notice, request, demand, or consent required or permitted to be given hereunder shall be in writing and delivered in person or by certified letter, with return receipt requested or by prepaid overnight delivery service, or by facsimile addressed to the Party for whom intended at the following addresses:

SELLER:

El Paso Production Company
Nine Greenway Plaza, Suite 2782
Houston, Texas 77046
Attn: Joe Mills
Sr. V.P. Acquisitions
Tel: (832) - 676-6367
Fax: (832) - 676-1192

BUYER:

Chesapeake Energy Corporation
6100 N. Western Ave.
Oklahoma City, OK 73118
Attn: Douglas J. Jacobson
Sr. Vice President
Tel: (405) 879-9233
Fax: (405) 879-9546

With copy to: Chesapeake Energy Corporation
6100 N. Western Ave.
Oklahoma City, OK 73118
Attn: Henry Hood
Tel: (405) 879-4000
Fax: (405) 879-9561

or at such other address as any of the above shall specify by like notice to the other.

15.5 Press Releases and Public Announcements. No Party shall issue any press release or make any public announcement relating to the subject matter of this Agreement prior to the Closing without the prior written approval of the other Party; provided, however, that any Party may make any public disclosure it believes in good faith is required by applicable law or any listing or trading agreement concerning its or its affiliates' publicly-traded securities (in which case the disclosing Party shall use all reasonable efforts to advise the other Party, and give the other Party an opportunity to comment on the proposed disclosure, prior to making the disclosure).

15.6 Personnel. Without Seller's prior written consent, for a period of eighteen (18) months from the Effective Time, Buyer will not directly or indirectly solicit for employment any person who is now employed by Seller or its affiliates involved in the exploration and production business in an executive, management, technical or professional position or otherwise considered by Seller to be a key employee. Attached hereto as Exhibit 15.6 is a listing of employees that Buyer may consider for employment. If Buyer chooses to extend offers to any of Seller's employees, those offers shall be at a base salary or hourly wages at least equal to their base salary or hourly wage level in effect on the Closing Date.

15.7 COMPLIANCE WITH EXPRESS NEGLIGENCE TEST. THE PARTIES AGREE THAT THE INDEMNIFICATION OBLIGATIONS OF THE INDEMNIFYING PARTY SHALL BE WITHOUT REGARD TO THE NEGLIGENCE OR STRICT LIABILITY OF THE INDEMNIFIED PERSON(S), WHETHER THE NEGLIGENCE OR STRICT LIABILITY IS ACTIVE, PASSIVE, JOINT, CONCURRENT OR SOLE.

15.8 Governing Law. This Agreement is governed by and must be construed according to the laws of the State of Texas, excluding any conflicts-of-law rule or principle that might apply the law of another jurisdiction. All disputes related to this Agreement shall be submitted to the jurisdiction of the courts of the State of Texas and venue shall be in the civil district courts of Harris County, Texas.

15.9 Exhibits. The Exhibits attached to this Agreement are incorporated into and made a part of this Agreement.

15.10 Fees, Expenses, Taxes and Recording.

(A) Each Party shall be solely responsible for all costs and expenses incurred by it in connection with this transaction (including, but not limited to fees and expenses of its counsel and accountants) and shall not be entitled to any reimbursements from the other Party, except as otherwise provided in this Agreement.

(B) Buyer shall, at its own cost, immediately record all instruments of conveyance and sale in the appropriate office of the state and county in which the lands covered by such instrument are located. Buyer shall immediately file for and obtain the necessary approval of all federal, Indian, tribal or state government agencies to the assignment of the Assets. The assignment of any state, federal or Indian tribal oil and gas leases shall be filed in the appropriate governmental offices on a form required and in compliance with the applicable rules of the applicable government agencies. Buyer shall supply Seller with a true and accurate photocopy reflecting the recording information of all the recorded and filed assignments within a reasonable period of time after their recording and filing.

15.11 Assignment. This Agreement or any part hereof may not be assigned by either Party without the prior written consent of the other Party; provided, however, upon notice to the other Party, either Party shall have the right to assign all or part of its rights (but none of its obligations) under this Agreement in order to qualify transfer of the Assets as a "like-kind" exchange for federal tax purposes. Subject to the foregoing, this Agreement is binding upon the Parties hereto and their respective successors and assigns.

15.12 Entire Agreement. This Agreement constitutes the entire agreement reached by the Parties with respect to the subject matter hereof, superseding all prior negotiations, discussions, agreements and understandings, whether oral or written, relating to such subject matter, except that the Confidentiality Agreement dated February 12, 2003, between the Parties shall remain in full force and effect in accordance with its terms through and until the Closing.

15.13 Severability. In the event that any one or more covenants, clauses or provisions of this Agreement shall be held invalid or illegal, such invalidity or unenforceability shall not affect any other provisions of this Agreement.

15.14 Captions. The captions in this Agreement are for convenience only and shall not be considered a part of or affect the construction or interpretation of any provision of this Agreement.

15.15 Counterpart Execution. This Agreement may be executed in any number of counterparts, and each such counterpart hereof shall be deemed to be an original, and all of which together shall constitute one and the same instrument.

15.16 Waiver of Certain Damages. Each of the Parties hereby waives and agrees not to seek consequential or punitive damages with respect to any claim, controversy, or dispute arising out of or relating to this Agreement or the breach thereof.

15.17 Amendments and Waivers. This Agreement may not be modified or amended except by an instrument in writing signed by both parties. Any party hereto may, only by an instrument in writing, waive compliance by another party with any term or provision of this Agreement on the part of such other party hereto to be performed or complied with. The waiver by any party hereto of a breach of any term or provision of this Agreement shall not be construed as a waiver of any subsequent breach.

15.18 PARENT GUARENTEE. Chesapeake Energy Corporation, an Oklahoma corporation as of the date of this Agreement as of and after Closing guarantees without reservation of condition all of the obligations of Buyer under this Agreement.

-Signature Page Follows-

Executed as of the day and year first above written.

SELLER:

EL PASO PRODUCTION COMPANY

By: /s/ J.A. Mills

J. A. Mills
Senior Vice President

NORIC, L.P.

By: Palomino, L.L.C.
as its general partner

By: NORIC, L.L.C.
as its sole member

By: /s/ J.A. Mills

J. A. Mills
Attorney-in-Fact

BUYER:

CHESAPEAKE EP CORPORATION

By: /s/ Douglas J. Jacobson

Douglas J. Jacobson
Vice President

GUARANTOR:

CHESAPEAKE ENERGY CORPORATION

By: /s/ Douglas J. Jacobson

Douglas J. Jacobson
Sr. Vice President

==

CHESAPEAKE ENERGY CORPORATION

and

the Subsidiary Guarantors named herein

7-7/8% SENIOR NOTES DUE 2004

TWELFTH SUPPLEMENTAL INDENTURE

DATED AS OF February 14, 2003

THE BANK OF NEW YORK

as successor Trustee to

United States Trust Company of New York

THIS TWELFTH SUPPLEMENTAL INDENTURE, dated as of February 14, 2003, is among Chesapeake Energy Corporation, an Oklahoma corporation (the Company), each of the parties identified under the caption Subsidiary Guarantors on the signature page hereto (the Subsidiary Guarantors) and The Bank of New York, as successor to United States Trust Company of New York, as Trustee.

RECITALS

WHEREAS, the Company, the Subsidiary Guarantors a party thereto and the Trustee entered into an Indenture, dated as of March 15, 1997, as supplemented prior to the date hereof (the Indenture), pursuant to which the Company has originally issued $150,000,000 in principal amount of 7(Y)(R)f(C)% Senior Notes due 2004 (the Notes); and

WHEREAS, Section 9.1(3) of the Indenture provides that the Company, the Subsidiary Guarantors and the Trustee may amend or supplement the Indenture without notice to or consent of any Holder to reflect the addition of any Subsidiary Guarantor, as provided for in the Indenture; and

WHEREAS, the Board of Directors of the Company has designated Chesapeake ORC, L.L.C. as a Restricted Subsidiary of the Company and desires to add such entity as a Subsidiary Guarantor under the Indenture; and

WHEREAS, all acts and things prescribed by the Indenture, by law and by the charter and the bylaws (or comparable constituent documents) of the Company, of the Subsidiary Guarantors and of the Trustee necessary to make this Twelfth Supplemental Indenture a valid instrument legally binding on the Company, the Subsidiary Guarantors and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, to comply with the provisions of the Indenture and in consideration of the above premises, the Company, the Subsidiary Guarantors and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE 1

Section 1.01. This Twelfth Supplemental Indenture is supplemental to the Indenture and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indenture for any and all purposes.

Section 1.02. This Twelfth Supplemental Indenture shall become effective immediately upon its execution and delivery by each of the Company, the Subsidiary Guarantors and the Trustee.

ARTICLE 2

From this date, in accordance with Section 10.3 and by executing this Twelfth Supplemental Indenture, Chesapeake ORC, L.L.C., an Oklahoma limited liability company, is subject to the provisions of the Indenture as a Subsidiary Guarantor to the extent provided for in Article X thereunder.

ARTICLE 3

Section 3.01. Except as specifically modified herein, the Indenture and the Notes are in all respects ratified and confirmed (mutatis mutandis) and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indenture.

Section 3.02. Except as otherwise expressly provided herein, no duties, responsibilities or liabilities are assumed, or shall be construed to be assumed, by the Trustee by reason of this Twelfth Supplemental Indenture. This Twelfth Supplemental Indenture is executed and accepted by the Trustee subject to all the terms and conditions set forth in the Indenture with the same force and effect as if those terms and conditions were repeated at length herein and made applicable to the Trustee with respect hereto.

Section 3.03. The Company hereby notifies the Trustee that Chesapeake ORC, L.L.C. has been designated by the Board of Directors of the Company as a Restricted Subsidiary (as that term is defined in the Indenture).

Section 3.04. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE AND ENFORCE THIS TWELFTH SUPPLEMENTAL INDENTURE.

Section 3.05. The parties may sign any number of copies of this Twelfth Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

[NEXT PAGE IS SIGNATURE PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this Twelfth Supplemental Indenture to be duly executed, all as of the date first written above.

COMPANY:

CHESAPEAKE ENERGY CORPORATION

By /s/ Aubrey K. McClendon

Name: Aubrey K. McClendon

Title: Chief Executive Officer

SUBSIDIARY GUARANTORS:

CHESAPEAKE BETA CORP.
CHESAPEAKE DELTA CORP.
CHESAPEAKE ENERGY LOUISIANA CORPORATION
CHESAPEAKE OPERATING, INC.
NOMAC DRILLING CORPORATION
CARMEN ACQUISITION, L.L.C.
CHESAPEAKE ACQUISITION, L.L.C.
CHESAPEAKE ENO ACQUISITION, L.L.C.
CHESAPEAKE FOCUS, L.L.C.
CHESAPEAKE KNAN ACQUISITION, L.L.C.
CHESAPEAKE MOUNTAIN FRONT, L.L.C.
CHESAPEAKE ORC, L.L.C.
CHESAPEAKE ROYALTY, L.L.C.
GOTHIC ENERGY, L.L.C.
GOTHIC PRODUCTION, L.L.C.
SAP ACQUISITION, L.L.C.
THE AMES COMPANY, L.L.C.

By /s/ Aubrey K. McClendon

Name: Aubrey K. McClendon

Title: Chief Executive Officer

CHESAPEAKE EXPLORATION LIMITED PARTNERSHIP
CHESAPEAKE LOUISIANA, L.P.

CHESAPEAKE PANHANDLE LIMITED
PARTNERSHIP
CHESAPEAKE-STAGHORN ACQUISITION L.P.
CHESAPEAKE SIGMA, L.P.

By: Chesapeake Operating, Inc. as general partner
of each representative entity

By /s/ Aubrey K. McClendon

Name: Aubrey K. McClendon

Title: Chief Executive Officer

TRUSTEE:

THE BANK OF NEW YORK, as
successor to United States
Trust Company of New York,
as Trustee

By /s/ Louis P. Young

Name: Louis P. Young

Title: Vice President

EXHIBIT 4.2.1

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CHESAPEAKE ENERGY CORPORATION

and

the Subsidiary Guarantors named herein

8-1/2% SENIOR NOTES DUE 2012

TWELFTH SUPPLEMENTAL INDENTURE

DATED AS OF February 14, 2003

THE BANK OF NEW YORK

as successor Trustee to

United States Trust Company of New York

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THIS TWELFTH SUPPLEMENTAL INDENTURE, dated as of February 14, 2003, is among Chesapeake Energy Corporation, an Oklahoma corporation (the "Company"), each of the parties identified under the caption "Subsidiary Guarantors" on the signature page hereto (the "Subsidiary Guarantors") and The Bank of New York, as successor to United States Trust Company of New York, as Trustee.

RECITALS

WHEREAS, the Company, the Subsidiary Guarantors a party thereto and the Trustee entered into an Indenture, dated as of March 15, 1997, as supplemented prior to the date hereof (the "Indenture"), pursuant to which the Company has originally issued $150,000,000 in principal amount of 8-1/2% Senior Notes due 2012 (the "Notes"); and

WHEREAS, Section 9.1(3) of the Indenture provides that the Company, the Subsidiary Guarantors and the Trustee may amend or supplement the Indenture without notice to or consent of any Holder to reflect the addition of any Subsidiary Guarantor, as provided for in the Indenture; and

WHEREAS, the Board of Directors of the Company has designated Chesapeake ORC, L.L.C. as a Restricted Subsidiary of the Company and desires to add such entity as a Subsidiary Guarantor under the Indenture; and

WHEREAS, all acts and things prescribed by the Indenture, by law and by the charter and the bylaws (or comparable constituent documents) of the Company, of the Subsidiary Guarantors and of the Trustee necessary to make this Twelfth Supplemental Indenture a valid instrument legally binding on the Company, the Subsidiary Guarantors and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, to comply with the provisions of the Indenture and in consideration of the above premises, the Company, the Subsidiary Guarantors and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE 1

Section 1.01. This Twelfth Supplemental Indenture is supplemental to the Indenture and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indenture for any and all purposes.

Section 1.02. This Twelfth Supplemental Indenture shall become effective immediately upon its execution and delivery by each of the Company, the Subsidiary Guarantors and the Trustee.

ARTICLE 2

From this date, in accordance with Section 10.3 and by executing this Twelfth Supplemental Indenture, Chesapeake ORC, L.L.C., an Oklahoma limited liability company, is subject to the provisions of the Indenture as a Subsidiary Guarantor to the extent provided for in Article X thereunder.

ARTICLE 3

Section 3.01. Except as specifically modified herein, the Indenture and the Notes are in all respects ratified and confirmed (mutatis mutandis) and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indenture.

Section 3.02. Except as otherwise expressly provided herein, no duties, responsibilities or liabilities are assumed, or shall be construed to be assumed, by the Trustee by reason of this Twelfth Supplemental Indenture. This Twelfth Supplemental Indenture is executed and accepted by the Trustee subject to all the terms and conditions set forth in the Indenture with the same force and effect as if those terms and conditions were repeated at length herein and made applicable to the Trustee with respect hereto.

Section 3.03. The Company hereby notifies the Trustee that Chesapeake ORC, L.L.C. has been designated by the Board of Directors of the Company as a Restricted Subsidiary (as that term is defined in the Indenture).

Section 3.04. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE AND ENFORCE THIS TWELFTH SUPPLEMENTAL INDENTURE.

Section 3.05. The parties may sign any number of copies of this Twelfth Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

[NEXT PAGE IS SIGNATURE PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this Twelfth Supplemental Indenture to be duly executed, all as of the date first written above.

COMPANY:

CHESAPEAKE ENERGY CORPORATION

By /s/ Aubrey K. McClendon
Name: Aubrey K. McClendon
Title: Chief Executive Officer

SUBSIDIARY GUARANTORS:

CHESAPEAKE BETA CORP.
CHESAPEAKE DELTA CORP.
CHESAPEAKE ENERGY LOUISIANA CORPORATION
CHESAPEAKE OPERATING, INC.
NOMAC DRILLING CORPORATION
CARMEN ACQUISITION, L.L.C.
CHESAPEAKE ACQUISITION, L.L.C.
CHESAPEAKE ENO ACQUISITION, L.L.C.
CHESAPEAKE FOCUS, L.L.C.
CHESAPEAKE KNAN ACQUISITION, L.L.C.
CHESAPEAKE MOUNTAIN FRONT, L.L.C.
CHESAPEAKE ORC, L.L.C.
CHESAPEAKE ROYALTY, L.L.C.
GOTHIC ENERGY, L.L.C.
GOTHIC PRODUCTION, L.L.C.
SAP ACQUISITION, L.L.C.
THE AMES COMPANY, L.L.C.

By /s/ Aubrey K. McClendon
Name: Aubrey K. McClendon
Title: Chief Executive Officer

CHESAPEAKE EXPLORATION LIMITED PARTNERSHIP
CHESAPEAKE LOUISIANA, L.P.
CHESAPEAKE PANHANDLE LIMITED PARTNERSHIP
CHESAPEAKE-STAGHORN ACQUISITION L.P.
CHESAPEAKE SIGMA, L.P.

By: Chesapeake Operating, Inc. as general partner of each representative entity

By /s/ Aubrey K. McClendon
Name: Aubrey K. McClendon
Title: Chief Executive Officer

TRUSTEE:

THE BANK OF NEW YORK, as successor to United States Trust Company of New York, as Trustee

By /s/ Louis P. Young
Name: Louis P. Young
Title: Vice President

EXHIBIT 4.3.1

CHESAPEAKE ENERGY CORPORATION

and

the Subsidiary Guarantors named herein

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8 1/8% SENIOR NOTES DUE 2011

SEVENTH SUPPLEMENTAL INDENTURE

DATED AS OF February 14, 2003

THE BANK OF NEW YORK

as successor Trustee to

United States Trust Company of New York

THIS SEVENTH SUPPLEMENTAL INDENTURE, dated as of February 14, 2003, is among Chesapeake Energy Corporation, an Oklahoma corporation (the "Company"), each of the parties identified under the caption "Subsidiary Guarantors" on the signature page hereto (the "Subsidiary Guarantors") and The Bank of New York, as successor to United States Trust Company of New York, as Trustee.

RECITALS

WHEREAS, the Company, the Subsidiary Guarantors a party thereto and the Trustee entered into an Indenture, dated as of April 6, 2001, as supplemented prior to the date hereof (the "Indenture"), pursuant to which the Company has originally issued $800,000,000 in principal amount of 8 1/8% Senior Notes due 2011 (the "Notes"); and

WHEREAS, Section 9.01(3) of the Indenture provides that the Company, the Subsidiary Guarantors and the Trustee may amend or supplement the Indenture without notice to or consent of any Holder to reflect the addition of any Subsidiary Guarantor, as provided for in the Indenture; and

WHEREAS, the Board of Directors of the Company has designated Chesapeake ORC, L.L.C. as a Restricted Subsidiary of the Company and desires to add such entity as a Subsidiary Guarantor under the Indenture; and

WHEREAS, all acts and things prescribed by the Indenture, by law and by the charter and the bylaws (or comparable constituent documents) of the Company, of the Subsidiary Guarantors and of the Trustee necessary to make this Seventh Supplemental Indenture a valid instrument legally binding on the Company, the Subsidiary Guarantors and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, to comply with the provisions of the Indenture and in consideration of the above premises, the Company, the Subsidiary Guarantors and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE 1

Section 1.01. This Seventh Supplemental Indenture is supplemental to the Indenture and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indenture for any and all purposes.

Section 1.02. This Seventh Supplemental Indenture shall become effective immediately upon its execution and delivery by each of the Company, the Subsidiary Guarantors and the Trustee.

ARTICLE 2

From this date, in accordance with Section 10.03 and by executing this Seventh Supplemental Indenture, Chesapeake ORC, L.L.C., an Oklahoma limited liability company, is subject to the provisions of the Indenture as a Subsidiary Guarantor to the extent provided for in Article Ten thereunder.

ARTICLE 3

Section 3.01. Except as specifically modified herein, the Indenture and the Notes are in all respects ratified and confirmed (mutatis mutandis) and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indenture.

Section 3.02. Except as otherwise expressly provided herein, no duties, responsibilities or liabilities are assumed, or shall be construed to be assumed, by the Trustee by reason of this Seventh Supplemental Indenture. This Seventh Supplemental Indenture is executed and accepted by the Trustee subject to all the terms and conditions set forth in the Indenture with the same force and effect as if those terms and conditions were repeated at length herein and made applicable to the Trustee with respect hereto.

Section 3.03. The Company hereby notifies the Trustee that Chesapeake ORC, L.L.C. has been designated by the Board of Directors of the Company as a Restricted Subsidiary (as that term is defined in the Indenture).

Section 3.04. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE AND ENFORCE THIS SEVENTH SUPPLEMENTAL INDENTURE.

Section 3.05. The parties may sign any number of copies of this Seventh Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

[NEXT PAGE IS SIGNATURE PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this Seventh Supplemental Indenture to be duly executed, all as of the date first written above.

COMPANY:

CHESAPEAKE ENERGY CORPORATION

By /s/ Aubrey K. McClendon

Name: Aubrey K. McClendon

Title: Chief Executive Officer

SUBSIDIARY GUARANTORS:

CHESAPEAKE BETA CORP.
CHESAPEAKE DELTA CORP.
CHESAPEAKE ENERGY LOUISIANA CORPORATION
CHESAPEAKE OPERATING, INC.
NOMAC DRILLING CORPORATION
CARMEN ACQUISITION, L.L.C.
CHESAPEAKE ACQUISITION, L.L.C.
CHESAPEAKE ENO ACQUISITION, L.L.C.
CHESAPEAKE FOCUS, L.L.C.
CHESAPEAKE KNAN ACQUISITION, L.L.C.
CHESAPEAKE MOUNTAIN FRONT, L.L.C.
CHESAPEAKE ORC, L.L.C.
CHESAPEAKE ROYALTY, L.L.C.
GOTHIC ENERGY, L.L.C.
GOTHIC PRODUCTION, L.L.C.
SAP ACQUISITION, L.L.C.
THE AMES COMPANY, L.L.C.

By /s/ Aubrey K. McClendon

Name: Aubrey K. McClendon

Title: Chief Executive Officer

CHESAPEAKE EXPLORATION LIMITED PARTNERSHIP
CHESAPEAKE LOUISIANA, L.P.
CHESAPEAKE PANHANDLE LIMITED PARTNERSHIP
CHESAPEAKE-STAGHORN ACQUISITION L.P.
CHESAPEAKE SIGMA, L.P.

By: Chesapeake Operating, Inc. as general partner of each representative entity

By /s/ Aubrey K. McClendon
Name: Aubrey K. McClendon
Title: Chief Executive Officer

TRUSTEE:

THE BANK OF NEW YORK, as successor to United States Trust Company of New York, as Trustee

By /s/ Louis P. Young
Name: Louis P. Young
Title: Vice President

CHESAPEAKE ENERGY CORPORATION

and

the Subsidiary Guarantors named herein

8.375% SENIOR NOTES DUE 2008

FOURTH SUPPLEMENTAL INDENTURE

DATED AS OF February 14, 2003

THE BANK OF NEW YORK

as Trustee

THIS FOURTH SUPPLEMENTAL INDENTURE, dated as of February 14, 2003, is among Chesapeake Energy Corporation, an Oklahoma corporation (the "Company"), each of the parties identified under the caption "Subsidiary Guarantors" on the signature page hereto (the "Subsidiary Guarantors") and The Bank of New York, as Trustee.

RECITALS

WHEREAS, the Company, the Subsidiary Guarantors a party thereto and the Trustee entered into an Indenture, dated as of November 5, 2001, as supplemented prior to the date hereof (the "Indenture"), pursuant to which the Company has originally issued $250,000,000 in principal amount of 8.375% Senior Notes due 2008 (the "Notes"); and

WHEREAS, Section 9.01(3) of the Indenture provides that the Company, the Subsidiary Guarantors and the Trustee may amend or supplement the Indenture without notice to or consent of any Holder to reflect the addition of any Subsidiary Guarantor, as provided for in the Indenture; and

WHEREAS, the Board of Directors of the Company has designated Chesapeake ORC, L.L.C. as a Restricted Subsidiary of the Company and desires to add such entity as a Subsidiary Guarantor under the Indenture; and

WHEREAS, all acts and things prescribed by the Indenture, by law and by the charter and the bylaws (or comparable constituent documents) of the Company, of the Subsidiary Guarantors and of the Trustee necessary to make this Fourth Supplemental Indenture a valid instrument legally binding on the Company, the Subsidiary Guarantors and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, to comply with the provisions of the Indenture and in consideration of the above premises, the Company, the Subsidiary Guarantors and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE 1

Section 1.01. This Fourth Supplemental Indenture is supplemental to the Indenture and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indenture for any and all purposes.

Section 1.02. This Fourth Supplemental Indenture shall become effective immediately upon its execution and delivery by each of the Company, the Subsidiary Guarantors and the Trustee.

ARTICLE 2

From this date, in accordance with Section 10.03 and by executing this Fourth Supplemental Indenture, Chesapeake ORC, L.L.C., an Oklahoma limited liability company, is subject to the provisions of the Indenture as a Subsidiary Guarantor to the extent provided for in Article Ten thereunder.

ARTICLE 3

Section 3.01. Except as specifically modified herein, the Indenture and the Notes are in all respects ratified and confirmed (mutatis mutandis) and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indenture.

Section 3.02. Except as otherwise expressly provided herein, no duties, responsibilities or liabilities are assumed, or shall be construed to be assumed, by the Trustee by reason of this Fourth Supplemental Indenture. This Fourth Supplemental Indenture is executed and accepted by the Trustee subject to all the terms and conditions set forth in the Indenture with the same force and effect as if those terms and conditions were repeated at length herein and made applicable to the Trustee with respect hereto.

Section 3.03. The Company hereby notifies the Trustee that Chesapeake ORC, L.L.C. has been designated by the Board of Directors of the Company as a Restricted Subsidiary (as that term is defined in the Indenture).

Section 3.04. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE AND ENFORCE THIS FOURTH SUPPLEMENTAL INDENTURE.

Section 3.05. The parties may sign any number of copies of this Fourth Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

[NEXT PAGE IS SIGNATURE PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this Fourth Supplemental Indenture to be duly executed, all as of the date first written above.

COMPANY:

CHESAPEAKE ENERGY CORPORATION

By /s/ Aubrey K. McClendon

Name: Aubrey K. McClendon

Title: Chief Executive Officer

SUBSIDIARY GUARANTORS:

CHESAPEAKE BETA CORP.
CHESAPEAKE DELTA CORP.
CHESAPEAKE ENERGY LOUISIANA CORPORATION
CHESAPEAKE OPERATING, INC.
NOMAC DRILLING CORPORATION
CARMEN ACQUISITION, L.L.C.
CHESAPEAKE ACQUISITION, L.L.C.
CHESAPEAKE ENO ACQUISITION, L.L.C.
CHESAPEAKE FOCUS, L.L.C.
CHESAPEAKE KNAN ACQUISITION, L.L.C.
CHESAPEAKE MOUNTAIN FRONT, L.L.C.
CHESAPEAKE ORC, L.L.C.
CHESAPEAKE ROYALTY, L.L.C.
GOTHIC ENERGY, L.L.C.
GOTHIC PRODUCTION, L.L.C.
SAP ACQUISITION, L.L.C.
THE AMES COMPANY, L.L.C.

By /s/ Aubrey K. McClendon

Name: Aubrey K. McClendon

Title: Chief Executive Officer

CHESAPEAKE EXPLORATION LIMITED
PARTNERSHIP
CHESAPEAKE LOUISIANA, L.P.
CHESAPEAKE PANHANDLE LIMITED
PARTNERSHIP
CHESAPEAKE-STAGHORN ACQUISITION L.P.
CHESAPEAKE SIGMA, L.P.

By: Chesapeake Operating, Inc. as general
partner of each representative entity

By /s/ Aubrey K. McClendon

Name: Aubrey K. McClendon

Title: Chief Executive Officer

TRUSTEE:

THE BANK OF NEW YORK, as Trustee

By /s/ Louis P. Young

Name: Louis P. Young

Title: Vice President

EXHIBIT 4.5.1

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CHESAPEAKE ENERGY CORPORATION

and

the Subsidiary Guarantors named herein

9% SENIOR NOTES DUE 2012

FIRST SUPPLEMENTAL INDENTURE

DATED AS OF February 14, 2003

THE BANK OF NEW YORK

as Trustee

==

THIS FIRST SUPPLEMENTAL INDENTURE, dated as of February 14, 2003, is among Chesapeake Energy Corporation, an Oklahoma corporation (the "Company"), each of the parties identified under the caption "Subsidiary Guarantors" on the signature page hereto (the "Subsidiary Guarantors") and The Bank of New York, as Trustee.

RECITALS

WHEREAS, the Company, the Subsidiary Guarantors a party thereto and the Trustee entered into an Indenture, dated as of August 12, 2002 (the "Indenture"), pursuant to which the Company has originally issued $250,000,000 in principal amount of 9% Senior Notes due 2012 (the "Notes"); and

WHEREAS, Section 9.01(3) of the Indenture provides that the Company, the Subsidiary Guarantors and the Trustee may amend or supplement the Indenture without notice to or consent of any Holder to reflect the addition of any Subsidiary Guarantor, as provided for in the Indenture; and

WHEREAS, the Board of Directors of the Company has designated Chesapeake ORC, L.L.C. as a Restricted Subsidiary of the Company and desires to add such entity as a Subsidiary Guarantor under the Indenture; and

WHEREAS, all acts and things prescribed by the Indenture, by law and by the charter and the bylaws (or comparable constituent documents) of the Company, of the Subsidiary Guarantors and of the Trustee necessary to make this First Supplemental Indenture a valid instrument legally binding on the Company, the Subsidiary Guarantors and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, to comply with the provisions of the Indenture and in consideration of the above premises, the Company, the Subsidiary Guarantors and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE 1

Section 1.01. This First Supplemental Indenture is supplemental to the Indenture and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indenture for any and all purposes.

Section 1.02. This First Supplemental Indenture shall become effective immediately upon its execution and delivery by each of the Company, the Subsidiary Guarantors and the Trustee.

ARTICLE 2

From this date, in accordance with Section 10.03 and by executing this First Supplemental Indenture, Chesapeake ORC, L.L.C., an Oklahoma limited liability company, is subject to the provisions of the Indenture as a Subsidiary Guarantor to the extent provided for in Article Ten thereunder.

ARTICLE 3

Section 3.01. Except as specifically modified herein, the Indenture and the Notes are in all respects ratified and confirmed (mutatis mutandis) and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indenture.

Section 3.02. Except as otherwise expressly provided herein, no duties, responsibilities or liabilities are assumed, or shall be construed to be assumed, by the Trustee by reason of this First Supplemental Indenture. This First Supplemental Indenture is executed and accepted by the Trustee subject to all the terms and conditions set forth in the Indenture with the same force and effect as if those terms and conditions were repeated at length herein and made applicable to the Trustee with respect hereto.

Section 3.03. The Company hereby notifies the Trustee that Chesapeake ORC, L.L.C. has been designated by the Board of Directors of the Company as a Restricted Subsidiary (as that term is defined in the Indenture).

Section 3.04. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE AND ENFORCE THIS FIRST SUPPLEMENTAL INDENTURE.

Section 3.05. The parties may sign any number of copies of this First Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

[NEXT PAGE IS SIGNATURE PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this First Supplemental Indenture to be duly executed, all as of the date first written above.

COMPANY:

CHESAPEAKE ENERGY CORPORATION

By /s/ Aubrey K. McClendon
Name: Aubrey K. McClendon
Title: Chief Executive Officer

SUBSIDIARY GUARANTORS:

CHESAPEAKE BETA CORP.
CHESAPEAKE DELTA CORP.
CHESAPEAKE ENERGY LOUISIANA CORPORATION
CHESAPEAKE OPERATING, INC.
NOMAC DRILLING CORPORATION
CARMEN ACQUISITION, L.L.C.
CHESAPEAKE ACQUISITION, L.L.C.
CHESAPEAKE ENO ACQUISITION, L.L.C.
CHESAPEAKE FOCUS, L.L.C.
CHESAPEAKE KNAN ACQUISITION, L.L.C.
CHESAPEAKE MOUNTAIN FRONT, L.L.C.
CHESAPEAKE ORC, L.L.C.
CHESAPEAKE ROYALTY, L.L.C.
GOTHIC ENERGY, L.L.C.
GOTHIC PRODUCTION, L.L.C.
SAP ACQUISITION, L.L.C.
THE AMES COMPANY, L.L.C.

By /s/ Aubrey K. McClendon
Name: Aubrey K. McClendon
Title: Chief Executive Officer

CHESAPEAKE EXPLORATION LIMITED PARTNERSHIP

CHESAPEAKE LOUISIANA, L.P.
CHESAPEAKE PANHANDLE LIMITED PARTNERSHIP
CHESAPEAKE-STAGHORN ACQUISITION L.P.
CHESAPEAKE SIGMA, L.P.

By: Chesapeake Operating, Inc. as general partner of each representative entity

By /s/ Aubrey K. McClendon
Name: Aubrey K. McClendon
Title: Chief Executive Officer

TRUSTEE:

THE BANK OF NEW YORK, as Trustee

By /s/ Louis P. Young
Name: Louis P. Young
Title: Vice President

EXHIBIT 4.6.1

CHESAPEAKE ENERGY CORPORATION

and

the Subsidiary Guarantors named herein

7.75% SENIOR NOTES DUE 2015

FIRST SUPPLEMENTAL INDENTURE

DATED AS OF February 14, 2003

THE BANK OF NEW YORK

as Trustee

THIS FIRST SUPPLEMENTAL INDENTURE, dated as of February 14, 2003, is among Chesapeake Energy Corporation, an Oklahoma corporation (the "Company"), each of the parties identified under the caption "Subsidiary Guarantors" on the signature page hereto (the "Subsidiary Guarantors") and The Bank of New York, as Trustee.

RECITALS

WHEREAS, the Company, the Subsidiary Guarantors a party thereto and the Trustee entered into an Indenture, dated as of December 20, 2002 (the "Indenture"), pursuant to which the Company has originally issued $150,000,000 in principal amount of 7.75% Senior Notes due 2015 (the "Notes"); and

WHEREAS, Section 9.01(3) of the Indenture provides that the Company, the Subsidiary Guarantors and the Trustee may amend or supplement the Indenture without notice to or consent of any Holder to reflect the addition of any Subsidiary Guarantor, as provided for in the Indenture; and

WHEREAS, the Board of Directors of the Company has designated Chesapeake ORC, L.L.C. as a Restricted Subsidiary of the Company and desires to add such entity as a Subsidiary Guarantor under the Indenture; and

WHEREAS, all acts and things prescribed by the Indenture, by law and by the charter and the bylaws (or comparable constituent documents) of the Company, of the Subsidiary Guarantors and of the Trustee necessary to make this First Supplemental Indenture a valid instrument legally binding on the Company, the Subsidiary Guarantors and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, to comply with the provisions of the Indenture and in consideration of the above premises, the Company, the Subsidiary Guarantors and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE 1

Section 1.01. This First Supplemental Indenture is supplemental to the Indenture and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indenture for any and all purposes.

Section 1.02. This First Supplemental Indenture shall become effective immediately upon its execution and delivery by each of the Company, the Subsidiary Guarantors and the Trustee.

ARTICLE 2

From this date, in accordance with Section 10.03 and by executing this First Supplemental Indenture, Chesapeake ORC, L.L.C., an Oklahoma limited liability company, is subject to the provisions of the Indenture as a Subsidiary Guarantor to the extent provided for in Article Ten thereunder.

ARTICLE 3

Section 3.01. Except as specifically modified herein, the Indenture and the Notes are in all respects ratified and confirmed (mutatis mutandis) and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indenture.

Section 3.02. Except as otherwise expressly provided herein, no duties, responsibilities or liabilities are assumed, or shall be construed to be assumed, by the Trustee by reason of this First Supplemental Indenture. This First Supplemental Indenture is executed and accepted by the Trustee subject to all the terms and conditions set forth in the Indenture with the same force and effect as if those terms and conditions were repeated at length herein and made applicable to the Trustee with respect hereto.

Section 3.03. The Company hereby notifies the Trustee that Chesapeake ORC, L.L.C. has been designated by the Board of Directors of the Company as a Restricted Subsidiary (as that term is defined in the Indenture).

Section 3.04. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE AND ENFORCE THIS FIRST SUPPLEMENTAL INDENTURE.

Section 3.05. The parties may sign any number of copies of this First Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

[NEXT PAGE IS SIGNATURE PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this First Supplemental Indenture to be duly executed, all as of the date first written above.

COMPANY:

CHESAPEAKE ENERGY CORPORATION

By /s/ Aubrey K. McClendon

Name: Aubrey K. McClendon

Title: Chief Executive Officer

SUBSIDIARY GUARANTORS:

CHESAPEAKE BETA CORP.
CHESAPEAKE DELTA CORP.
CHESAPEAKE ENERGY LOUISIANA CORPORATION
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SAP ACQUISITION, L.L.C.
THE AMES COMPANY, L.L.C.

By /s/ Aubrey K. McClendon

Name: Aubrey K. McClendon

Title: Chief Executive Officer

CHESAPEAKE EXPLORATION LIMITED PARTNERSHIP

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CHESAPEAKE SIGMA, L.P.

By: Chesapeake Operating, Inc. as general partner of each representative entity

By /s/ Aubrey K. McClendon
Name: Aubrey K. McClendon
Title: Chief Executive Officer

TRUSTEE:

THE BANK OF NEW YORK, as Trustee

By /s/ Louis P. Young
Name: Louis P. Young
Title: Vice President

Exhibit 10.1.14

CHESAPEAKE ENERGY CORPORATION

2003 STOCK AWARD PLAN FOR NON-EMPLOYEE DIRECTORS

1. Purposes of the Plan. This Plan is established by the Company to aid in attracting and retaining persons of outstanding competence to serve on the Board of Directors who are not employed by the Company. The Plan is intended to enable such persons to acquire or increase ownership interests in the Company on a basis that will encourage them to use their best efforts to promote the growth and profitability of the Company. Consistent with these objectives, the Plan provides for the award of Shares to Non-Employee Directors on the terms and subject to the conditions set forth in the Plan.

2. Establishment. The Plan is effective as of January 3, 2003.

3. Definitions. As used herein, the following definitions shall apply:

(a) "Applicable Laws" means the requirements of state corporate laws, United States federal and state securities laws, the Code, and any stock exchange or quotation system on which the Common Stock is listed or quoted.

(b) "Board" means the Board of Directors of the Company.

(c) "Code" means the Internal Revenue Code of 1986, as amended.

(d) "Common Stock" means the Company's common stock.

(e) "Company" means Chesapeake Energy Corporation, an Oklahoma corporation, and any successor to the Company.

(f) "Director" means a member of the Board.

(g) "Non-Employee Director" means a Director who, as of the date first elected or appointed to the Board, is not an officer or otherwise employed by the Company or any of its subsidiaries.

(h) "Paragraph" means a paragraph of the Plan.

(i) "Participant" means a Non-Employee Director who has been awarded Shares under the Plan.

(j) "Plan" means the Chesapeake Energy Corporation 2003 Stock Award Plan for Non-Employee Directors, as may be amended from time to time.

(k) "Share" means a share of the Common Stock, as adjusted in accordance with Paragraph 7.

(l) "Shareholder Approval" means approval by the holders of a majority of the outstanding shares of Common Stock, present or represented and entitled to vote at a meeting called for such purposes.

4. Stock Subject to the Plan. Subject to the provisions of Paragraph 7, the maximum aggregate number of Shares that may be awarded under the Plan is 50,000 Shares.

5. Administration of the Plan. The Plan shall be administered by the Board. Subject to the provisions of the Plan, the Board shall have the authority to prescribe, amend and rescind rules and regulations relating to the Plan and to construe and interpret the terms of the Plan and awards made pursuant to the Plan. All decisions, determinations and interpretations of the Board shall be final and binding on all Participants.

6. Award of Shares.

(a) Each individual who becomes a Non-Employee Director after the effective date of the Plan shall be awarded 10,000 Shares on his or her first day of service as a Non-Employee Director.

(b) In consideration for the Shares awarded under the Plan, each Participant shall pay the Company an amount equal to the aggregate par value of the Shares awarded (the "Share Consideration"). The Share Consideration shall be payable in cash, provided the Company shall withhold the Share Consideration from the first payment of director fees to be made by the Company to the Participant as a Non-Employee Director if the Share Consideration has not been earlier paid. A Participant must pay the amount of taxes required by law as a result of an award of Shares under the Plan.

(c) Upon receipt of the Share Consideration and subject to Paragraph 9, the Company shall issue the Participant a stock certificate evidencing the Shares awarded to the Participant under the Plan.

7. Adjustments Upon Changes in Capitalization. Subject to any required action by the shareholders of the Company, the number and type of Shares which have been authorized for issuance under the Plan but as to which no Shares have yet been awarded, shall be proportionately adjusted for any increase or decrease in the number or type of issued Shares resulting from a stock split, reverse stock split, stock dividend, combination or reclassification of the Common Stock, or any other increase or decrease in the number of issued shares of Common Stock effected without receipt of consideration by the Company. The conversion of any convertible securities of the Company shall not be deemed to have been "effected without receipt of consideration." Such adjustment shall be made by the Board, whose determination in that respect shall be final, binding and conclusive.

8. Amendment and Termination of the Plan. The Board may suspend or terminate the Plan at any time. In addition, the Board may, from time to time, amend the Plan in any manner, but may not adopt any amendment without Shareholder Approval if in the opinion of counsel to the Company, Shareholder Approval is required by any Applicable Laws.

9. Conditions Upon Issuance of Shares.

(a) Legal Compliance. Shares awarded pursuant to the Plan shall not be issued unless the issuance and delivery of such Shares comply with Applicable Laws. The inability of the Company to obtain authority from any regulatory body having jurisdiction, which authority is deemed by the Company's legal counsel to be necessary to the lawful issuance and sale of any Shares hereunder, shall relieve the Company of any liability in respect of the failure to issue such Shares as to which such requisite authority shall not have been obtained

(b) Investment Representations. As a condition to the award of Shares under the Plan, the Board may require a Participant to represent and warrant at the time of the award that the Shares will be held only for investment and without any present intention to sell or distribute such Shares if, in the opinion of legal counsel to the Company, such a representation is necessary or appropriate.

10. Reservation of Shares. The Company shall at all times reserve and keep available such number of authorized and unissued Shares or Shares in its reserve of treasury stock as shall be sufficient to satisfy the requirements of the Plan.

11. Right to Continued Board Membership. Participation in the Plan shall not give any Participant any right to remain on the Board.

12. Construction. The titles and headings of the sections in the Plan are for the convenience of reference only, and in the event of any conflict, the text of the Plan, rather than such titles or headings, shall control.

13. Governing Law. The Plan shall be governed by and construed in accordance with the laws of the State of Oklahoma, except as superseded by applicable federal law.

CHESAPEAKE ENERGY CORPORATION

401(k) MAKE-UP PLAN

CHESAPEAKE ENERGY CORPORATION
401(k) MAKE-UP PLAN

Table of Contents

CHESAPEAKE ENERGY CORPORATION
401(k) MAKE-UP PLAN

ARTICLE I
Establishment and Purpose

1.1 Establishment. Chesapeake Energy Corporation ("Company"), hereby adopts the Chesapeake Energy Corporation 401(k) Make-Up Plan effective January 1, 2003.

1.2 Purpose. The Plan shall provide Eligible Employees the ability to defer payment of compensation earned and/or granted by the Company, its Subsidiaries and/or Affiliated Entities. The Plan is intended to provide such Eligible Employees with a degree of flexibility in their financial planning. The Plan is also intended to provide the opportunity to make contributions which would otherwise be made under the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan ("Qualified Plan") but which cannot be made under the Qualified Plan due to the limitations imposed by (i) Section 401(a)(17) of the Internal Revenue Code of 1986, as amended (the "Code"), which limits the annual compensation that may be taken into account in computing benefits under plans qualified under Sections 401(a) and 501(a) of the Code, and (ii) Sections 401(k) and 402(g) of the Code which limits benefits that may be deferred into a defined contribution plan qualified under Section 401(k) of the Code or which may be contributed by the Company as a "matching contribution" under Section 401(m) of the Code.

1.3 ERISA Status. The Plan is intended to qualify for the exemptions provided under Title I of ERISA for plans that are not tax-qualified and that are maintained primarily to provide deferred compensation for a select group of management or highly compensated employees as defined in Section 201(2) of ERISA.

ARTICLE II
Definitions

2.1 Definitions. For purposes of this Plan, the following definitions shall apply:

(a) "Account" means the record keeping accounts maintained in the name of a Participant to which Deferred Amounts, Company Contributions and any income, earnings or losses thereon are recorded pursuant to the provisions of Article VII.

(b) "Affiliated Entity" means any partnership or limited liability company in which a majority of the partnership or other similar interest thereof is owned or controlled, directly or indirectly, by the Company or one or more of its Subsidiaries or Affiliated Entities or a combination thereof. For purposes hereof, the Company, a Subsidiary or an Affiliated Entity shall be deemed to have a majority ownership interest in a partnership or limited liability company if the Company, such Subsidiary or Affiliated Entity shall be allocated a majority of partnership or limited liability company gains or losses or shall be or control a managing director or a general partner of such partnership or limited liability company.

(c) "Base Salary" means the Participant's annualized gross rate of salary paid before any deductions of any kind whatsoever excluding overtime, bonuses, commissions and other extraordinary compensation.

(d) "Beneficiary" means the person, persons, trust, or other entity designated by a Participant on a beneficiary designation form adopted by the Committee to receive benefits, if any, under this Plan at such Participant's death pursuant to Section 6.3.

(e) "Board" means the Board of Directors of the Company.

(f) "Bonus" means the Participant's cash performance bonus(es) to be paid during each calendar year before any deductions of any kind whatsoever.

(g) "Change of Control" means the occurrence of any of the following:

(i) the acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or14(d)(2) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 20% or more of either (A) the then outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (B) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors (the "Outstanding Company Voting Securities"). For purposes of this paragraph 2.1(g) the following acquisitions by a Person will not constitute a Change of Control: (1) any acquisition directly from the Company; (2) any acquisition by the Company; (3) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company; or (4) any acquisition by any corporation pursuant to a transaction which complies with clauses (A), (B) and (C) of paragraph (iii);

(ii) the individuals who, as of the date hereof, constitute the board of directors (the "Incumbent Board") cease for any reason to constitute at least a majority of the board of directors. Any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareholders, is approved by a vote of at least a majority of the directors then comprising the Incumbent Board will be considered a member of the Incumbent Board as of the date hereof, but any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Incumbent Board will not be deemed a member of the Incumbent Board as of the date hereof;

(iii) the consummation of a reorganization, merger, consolidation or sale or other disposition of all or substantially all of the assets of the Company (a "Business Combination"), unless following such Business Combination: (A) all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 60% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (B) no Person (excluding any corporation resulting from such Business Combination or any employee benefit plan (or related trust) of the Company or such corporation resulting from such Business Combination) beneficially owns, directly or indirectly, 20% or more of, respectively, the then outstanding shares of common stock of the corporation resulting from such Business Combination or the combined voting power of the then outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (C) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or

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

(h) "Code" means the Internal Revenue Code of 1986, as amended from time to time, and any Regulations relating thereto.

(i) "Committee" means the committee appointed by the Board of Directors of the Company to manage and administer the Plan.

(j) "Company Contribution" means, collectively, the Supplemental Matching Contribution and any Discretionary Contributions made by the Company for the benefit of a Participant pursuant to Article V.

(k) "Deferred Amount" means the portion of a Participant's Base Salary and Bonus which the Participant elects to defer pursuant to Article IV. Deferred Amounts shall be determined by reference to the Plan Year in which the Base Salary is earned and the Bonus would otherwise have been paid.

(l) "Disability" means either a physical or mental disability as a result of which, at least 180 days after commencement of such disability, the Participant is determined, by a physician selected by the Company and acceptable to the Participant or the Participant's legal representative, to be totally and permanently disabled.

(m) "Discretionary Contributions" means a discretionary contribution made by the Company to a Participant's Account pursuant to Section 5.4 of the Plan.

(n) "Election" means an affirmative election made by an Eligible Employee on a deferral election form provided by the Committee with respect to which the Eligible Employee may elect Deferred Amounts under this Plan.

(o) "Eligible Employee" means (i) an employee who (A) is designated by the Committee as belonging to a "select group of management or highly compensated employees," as such phrase is defined under ERISA; (B) receives a Base Salary of $100,000 or more during the twelve months immediately preceding the applicable Plan Year; (C) has five or more Years of Service with the Company, a Subsidiary or an Affiliated Entity prior to the Plan Year and (D) is employed by the Company, a Subsidiary or an Affiliated Entity on December 31 preceding the applicable Plan Year; or (ii) an employee who is otherwise determined by the Committee to be eligible to participate in the Plan.

(p) "Employer" shall mean the Company and/or any Subsidiary or Affiliated Entity that employs a Participant.

(q) "ERISA" means the Employee Retirement Income Security Act of 1974, as amended.

(r) "Participant" means an Eligible Employee who has Deferred Amounts and/or Company Contributions credited to an Account under this Plan.

(s) "Plan" means this Chesapeake Energy Corporation 401(k) Make-Up Plan, as amended from time to time.

(t) "Plan Year" means the 12-month period beginning on January 1st and ending on December 31st.

(u) "Qualified Plan" means the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan.

(v) "Qualified Plan Matching Contribution" means the total of all matching contributions made by the Company to the Qualified Plan for the benefit of a Participant under and in accordance with the terms of the Qualified Plan in any Plan Year.

(w) "Retirement Date" means the date a Participant is at least age 55 and has at least 10 Years of Service with the Company, a Subsidiary or an Affiliated Entity.

(x) "Stock" means Chesapeake Energy Corporation common stock.

(y) "Subsidiary" shall have the same meaning set forth in Section 424 of the Code.

(z) "Supplemental Matching Contribution" means the matching contribution made by the Company for the benefit of a Participant pursuant to Article V of the Plan.

(aa) "Trust" shall mean a "grantor trust" as defined in Section 671 of the Code, which may be established by the Company to provide a source of funding for amounts deferred hereunder.

(bb) "Valuation Date" means the close of business on the applicable business day assuming daily valuations of Accounts.

(cc) "Year of Service" means the active employment with the Company, a Subsidiary or an Affiliated Entity for 12 consecutive months.

ARTICLE III
ELIGIBILITY AND PARTICIPATION

The Committee shall provide Eligible Employees selected for participation in this Plan with notice of eligibility and permit such Eligible Employee the opportunity to make an Election pursuant to Article IV. Notice may be given at the time and in the manner as the Committee may determine. All determinations regarding eligibility for participation in the Plan will be made by the Committee. The determinations of the Committee will be final and binding. Eligible Employees who have made an Election under this Plan shall continue as a Participant as long as there is a balance credited to his or her Account.

ARTICLE IV
ELECTIVE DEFERRALS

4.1 Deferrals. Eligible Employees may make elective deferrals with respect to the following sources in accordance with the provisions of this Article IV:

(a) Amount Eligible for Deferral.

(i) Bonus. An Eligible Employee may elect to defer under this Plan and the Chesapeake Energy Corporation Deferred Compensation Plan up to 100% of the Eligible Employee's Bonus that may be awarded by the Company, a Subsidiary or an Affiliated Entity. The amount deferred shall be specified as a percentage of any Bonus which may be awarded to an Eligible Employee in a Plan Year.

(ii) Base Salary. An Eligible Employee may elect to defer under this Plan and the Chesapeake Energy Corporation Deferred Compensation Plan up to 60% of the Eligible Employee's Base Salary as long as such deferral does not reduce such Eligible Employee's Base Salary below an amount necessary to satisfy applicable employment withholding tax obligations, benefit plan contributions, and income tax withholding obligations.

(b) Deferrals. The amount of Base Salary and Bonus deferred by a Participant under this Plan shall be equal to (i) the percentage of Base Salary and Bonus the Participant elects to defer reduced by (ii) the maximum amount the Participant is permitted to contribute to the Qualified Plan pursuant to the terms of the Qualified Plan.

4.2 Timing of Deferral Election. Except as may be permitted by the Code or the regulations adopted thereunder, the Election to defer shall apply to Base Salary earned and Bonus paid during the Plan Year which commences immediately following the year in which the Election is made. Elections must be completed and filed before the December 1 preceding the beginning of the Plan Year when such elections are to be applicable. Elections shall only be applicable to Base Salary which has not been earned, and to Bonus which has not been finally determined and/or awarded. Eligible Employees who are selected to participate in the Plan during a Plan Year will be permitted to participate in the Plan if an Election form is completed and filed at least 30 days prior to the date participation in the Plan is scheduled to commence.

Elections will continue to apply to subsequent Plan Years unless and until the Participant files a revised Election with the Committee by December 1 of the year preceding the Plan Year when the revised election is to be applicable.

ARTICLE V
COMPANY CONTRIBUTIONS

5.1 Purpose. Section 401(a)(17) of the Code limits the amount of compensation that may be taken into account under a tax-qualified Qualified Plan for any year to $200,000, adjusted annually by the Internal Revenue Service for cost of living increases. Section 401(m) of the Code (and the Qualified Plan) limits the amount which may be contributed by the Company as a "matching contribution" to the Qualified Plan. Section 402(g) of the Code limits the amount of deferrals of compensation under a tax-qualified Qualified Plan with a Section 401(k) feature to $12,000 as adjusted annually by the Internal Revenue Service. The purpose of this Article V is to restore to Participants any benefits that would have been available to them under the Qualified Plan had the limitations of Sections 401(a)(17), 401(m) or 402(g) of the Code not been imposed.

5.2 Eligibility for Supplemental Matching Contributions. To be eligible for Supplemental Matching Contributions, an Eligible Employee must (a) be a Participant in the Qualified Plan, (b) have made the maximum contribution allowable under the Qualified Plan and (c) have experienced a reduction in the benefits he would have received from the Qualified Plan as a result of the limitations of Section 401(a)(17) or 402(g) of the Code.

5.3 Calculation of Supplemental Matching Contributions. Each Plan Year, the Company will make a Supplemental Matching Contribution to this Plan on behalf of each Participant in an amount equal to the difference between (i) and (ii) below:

(i) An amount equal to 100% percent of the amount deferred by the Participant pursuant to Section 4.1 for the Plan Year, without giving effect to any reductions required by the limitations imposed by the Code on or under the Qualified Plan but not to exceed a percentage of such Participant's Base Salary and Bonus (the "Company Maximum Match") as determined by the Committee in its discretion for such Plan Year. For purposes of the initial Plan Year, the Company Maximum Match shall be 15%;

LESS

(ii) The amount of the Qualified Plan Matching Contribution actually allocated to the Qualified Plan on the Participant's behalf for the Plan Year.

Provided, the Supplemental Matching Contribution will only be made on behalf of a Participant for any Plan Year if such Participant has made the maximum deferral of compensation as permitted under Section 402(g) to the Qualified Plan and the Company has made the maximum Qualified Plan Matching Contribution to the Qualified Plan as permitted under Section 401(m) of the Code and the Qualified Plan as determined by the Committee in its discretion for such Plan Year.

5.4 Discretionary Contributions. The Committee may also make any contribution it so elects, as either an additional match or such other basis chosen by the Committee, to a Participant in any given Plan Year.

ARTICLE VI
PAYMENT OF BENEFITS

6.1 Payment Upon Termination or Disability.

(a) Timing. Unless otherwise distributed in accordance with the terms of this Plan, payment of a Participant's vested Account shall commence as described below following (i) a Participant's termination of employment for any reason, or (ii) the date the Participant is determined by the Committee to have incurred a Disability.

(b) Installment Payments. If a Participant's vested Account balance is at least $50,000 and the Participant terminates employment or becomes Disabled after attaining the Participant's Retirement Date, the Participant is eligible to elect annual installment payments payable over a period of 1 to 20 years. The first installment shall commence within 30 days of the calendar quarter following the one-year anniversary of the Participant's date of termination or date of Disability with each subsequent annual installment paid in January of each year until all installment payments have been paid. If a Participant qualifies for an installment payment but fails to make an effective designation as to the method of payment, the Participant's Account will be distributed in annual installments over 10 years.

(c) Lump Sum Payment. If a Participant terminates employment for any reason prior to his or her Retirement Date or with an Account balance less than $50,000, payment will be made in the form of a lump sum within 30 days following the month of the Participant's date of termination or Disability. If a Participant terminates employment or becomes Disabled and is eligible to receive installment payments but elects to receive payment in the form of a single lump sum, payment will be made 13 months following the Participant's date of termination or date of Disability.

(d) Changes in Method of Payment. The Committee, in its sole discretion, may permit a different method of payment if a Participant is determined by the Committee to be subject to special circumstances. The method of payment may be changed from time to time by the Participant, but in no event will such change be considered valid if the change occurs within the 12-month period prior to the date payment is scheduled to commence without the approval of the Committee.

6.2 Payment to Beneficiary. If a Participant dies with a balance credited to the Participant's Account the then current vested balance of the Participant's Account shall be paid to the Participant's Beneficiary in a lump sum.

6.3 Beneficiary Designations. A Participant shall designate on a beneficiary designation form provided by the Committee a Beneficiary who, upon the Participant's death, will receive payments that otherwise would have been paid to the Participant under the Plan. All Beneficiary designations must be in writing. Beneficiary designations will be effective only if and when delivered to the Committee during the lifetime of the Participant. A Participant may change a Beneficiary or Beneficiaries by filing a new beneficiary designation form. The latest beneficiary designation form shall apply to the Accounts of the Participant. If a Beneficiary of a Participant predeceases the Participant, the designation of such Beneficiary shall be void. If a Beneficiary to whom benefits under the Plan remain unpaid dies after the Participant and the Participant failed to specify a contingent Beneficiary on the appropriate Beneficiary designation form, the balance of the Participant's Account will be paid to such Beneficiary's estate. If a Participant fails to designate a Beneficiary or if such designation is ineffective, in whole or in part, any payment that otherwise would have been paid to such Participant shall be paid to the Participant's estate.

6.4 Changes in Payment Date.

(a) Emergency. If the Participant experiences an unforeseeable emergency, payment of the Participant's Account, attributable to Deferred Amounts, prior to the Participant's termination date may occur with the approval of the Committee subject to the following conditions:

(i) The minimum emergency withdrawal is the lesser of $25,000 or 100% of the Account balance;

(ii) The Participant must submit a written request to the Committee at least 30 days prior to the date the Participant requests payment. The written notice must state the reason necessitating the early payment and provide documentation that the financial hardship cannot be satisfied by other assets;

(iii) The emergency must result from a severe financial hardship to the Participant resulting from (1) a sudden and unexpected illness or accident of the Participant or of a dependent (as defined in Section 152(a) of the Code) of the Participant, (2) loss of the Participant's property due to casualty, or (3) other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant. The need to send a Participant's child to college or the desire to purchase a home shall not be considered emergencies for purposes of this Subsection 6.4(a);

(iv) The decision whether to allow an emergency withdrawal from the Participant's Account shall be made in the sole and absolute discretion of the Committee; and

(v) In the event a Participant receives an emergency payment, all deferrals elected for such Plan Year shall cease, and the Participant shall not be eligible to participate in the Plan for the balance of the Plan Year and one additional Plan Year.

(b) Nonscheduled Withdrawal. A Participant may request an unscheduled distribution of not less than 25% of the portion of his Account attributable to Deferred Amounts. However, the distribution will be subject to a 10% penalty of the amount requested. In the event a Participant requests a nonscheduled withdrawal, (i) all deferrals under this Plan for such Plan Year shall cease, (ii) the Participant shall not be eligible to participate in the Plan for the balance of the Plan Year and one additional Plan Year, and (iii) the Participant shall forfeit the portion of Company Contributions (vested and unvested) held in the Participant's Account in proportion to the Deferred Amounts distributed to the Participant.

ARTICLE VII
ACCOUNTS AND INVESTMENT

7.1 Establishment of Account. There shall be established and maintained by the Company a separate Account in the name of each Participant who has elected to defer Base Salary and Bonus under the terms of this Plan.

7.2 Balance of Account. The balance of each Participant's Account shall include Deferred Amounts and Company Contributions, plus income and gains credited with respect to the deemed investments selected by the Participant based on the benchmark funds provided by the Committee. Losses from the deemed investments in the benchmark funds shall reduce the Participant's Account balance. The balance of each Participant's Account shall be determined as of each Valuation Date.

7.3 Investment Direction - Deferred Amounts. The Committee may, in its sole discretion, offer more than one benchmark fund as a deemed investment alternative. If the Committee elects to offer more than one deemed investment alternative, on such form as the Committee prescribes, each Participant may select among the different benchmark funds for Deferred Amounts. However, the Committee is not required to accept the deemed investments made by the Participant. No actual investments shall be made by Participants. The deemed investments in benchmark funds are only for the purpose of determining the Company's payment obligation under the Plan. A Participant who has a choice of more than one such benchmark fund may, as frequently as daily, modify his election of benchmark funds through a procedure designated by the Committee. Such modification will be in accordance with rules and procedures adopted by the Committee. The balance of each Participant's Account shall be deemed invested in one or more benchmark funds on each Valuation Date, and income or losses shall accrue on such balance upon such date, from the previous Valuation Date.

7.4 Investment of Company Contributions. Company Contributions will be deemed to be invested solely in Stock. Distributions of the Participant's Account balance attributable to Company Contributions will be made in Stock. A Participant may not elect to diversify the portion of his Account attributable to Company Contributions. On the last day of each calendar quarter the Company shall transfer to the trustee of the Trust cash equal to the amount of the Company Contribution for the quarter. The trustee shall purchase shares of Stock on the open market on the last business day of each calendar quarter. Shares of Stock shall be issued in the name of the trustee of the Trust. During the period that Stock is held by the trustee, cash dividends will not be paid with respect to such Stock and Stock dividends will not be reinvested in the Participant's Account. During the period Stock is held by the Trust, Participants will not have the right to vote such shares of Stock and the Participant will not have any other incidents of ownership or rights as a shareholder with respect to such Stock.

7.5 Vesting.

(a) Deferred Amounts. Subject to the conditions and limitations on payment of benefits under the Plan, a Participant shall always have a fully vested and nonforfeitable beneficial interest in the balance standing to the credit of the Participant's Account attributable to Deferred Amounts and any income, earnings or losses thereon.

(b) Company Contributions. Supplemental Matching Contributions and any income, earnings or losses thereon shall vest at the rate of 25% per year for each Year of Service with the Company from the date of the contribution. Discretionary Contributions shall vest as determined by the Committee upon the grant of a Discretionary Contribution. If a Participant terminates employment prior to vesting, the unvested Company Contributions and any income, earnings or losses thereon shall be forfeited. Forfeited amounts shall be used to offset future contributions by the Company. In the event termination is due to death, Disability or retirement, the Committee may, in its sole and absolute discretion, accelerate vesting. Upon the occurrence of a Change of Control, all Participants shall be deemed to be 100% vested in all Company Contributions credited to their Account.

7.6 Account Statements. The Committee shall provide each Participant with a statement of the status of the Participant's Account under the Plan. The Committee shall provide such statement quarterly or at such other times as the Committee may determine. Account statements shall be in the format prescribed by the Committee.

ARTICLE VIII
ADMINISTRATION

8.1 Administration. The Plan shall be administered, construed and interpreted by the Committee. The Committee shall have the sole authority and discretion to determine eligibility for benefits and to construe the terms of the Plan. The determinations by the Committee as to any disputed questions arising under the Plan, including the eligibility to become a Participant in the Plan and the amounts of benefits under the Plan, and the construction and interpretation by the Committee of any provision of the Plan, shall be final, conclusive and binding upon all persons including Participants, their beneficiaries, the Company, its stockholders and employees and the Employers.

8.2 Indemnification and Exculpation. The members of the Committee and its agents shall be indemnified and held harmless by the Company against and from any and all loss, cost, liability or expense that may be imposed upon or reasonably incurred by them in connection with or resulting from any claim, action, suit or proceeding to which they may be a party or in which they may be involved by reason of any action taken or failure to act under this Plan and against and from any and all amounts paid by them in settlement (with the Company's written approval) or paid by them in satisfaction of a judgment in any such action, suit or proceeding. The foregoing provisions shall not be applicable to any person if the loss, cost, liability or expense is due to such person's gross negligence or willful misconduct.

8.3 Rules of Conduct. The Committee shall adopt rules for the conduct of its business and the administration of this Plan as it considers desirable, provided they do not conflict with the provisions of this Plan.

8.4 Legal, Accounting, Clerical and Other Services. The Committee may authorize one or more of its members or any agent to act on its behalf and may contract for legal, accounting, clerical and other services to carry out this Plan. The Company shall pay all expenses of the Committee.

8.5 Records of Administration. The Committee shall keep or designate another party to keep records reflecting the administration of this Plan which shall be subject to audit by the Company.

8.6 Expenses. The expenses of administering the Plan shall be borne by the Company.

8.7 Liability. No member of the Board or of the Committee shall be liable for any act or action, whether of commission or omission, taken by any other member, or by any officer, agent, or employee of the Company or of any such body, nor, except in circumstances involving his bad faith, for anything done or omitted to be done by himself.

8.8 Claims Review Procedures. The following claim procedures shall apply until such time as a Change of Control has occurred. During the 24-month period following a Change of Control, these procedures shall apply only to the extent the claimant requests their application. After the expiration of the 24-month period following a Change of Control, then, these procedures shall again apply until the occurrence of a subsequent Change of Control.

(a) Denial of Claim. If a claim for benefits is wholly or partially denied, the claimant shall be given notice in writing of the denial within a reasonable time after the receipt of the claim, but not later than 90 days after the receipt of the claim. However, if special circumstances require an extension, written notice of the extension shall be furnished to the claimant before the termination of the 90-day period. In no event shall the extension exceed a period of 90 days after the expiration of the initial 90-day period. The notice of the denial shall contain the following information written in a manner that may be understood by a claimant:

(i) The specific reasons for the denial;

(ii) Specific reference to pertinent Plan provisions on which the denial is based;

(iii) A description of any additional material or information necessary for the claimant to perfect his claim and an explanation of why such material or information is necessary;

(iv) An explanation that a full and fair review by the Committee of the denial may be requested by the claimant or his authorized representative by filing a written request for a review with the Committee within 60 days after the notice of the denial is received; and

(v) If a request for review is filed, the claimant or his authorized representative may review pertinent documents and submit issues and comments in writing within the 60-day period described in Section 8.8(a)(iv).

(b) Decisions After Review. The decision of the Committee with respect to the review of the denial shall be made promptly and in writing, but not later than 60 days after the Committee receives the request for the review. However, if special circumstances require an extension of time, a decision shall be rendered not later than 120 days after the receipt of the request for review. A written notice of the extension shall be furnished to the claimant prior to the expiration of the initial 60-day period. The claimant shall be given a copy of the decision, which shall state, in a manner calculated to be understood by the claimant, the specific reasons for the decision and specific references to the pertinent Plan provisions on which the decision is based.

(c) Other Procedures. Notwithstanding the foregoing, the Committee may, in its discretion, adopt different procedures for different claims without being bound by past actions. Any procedures adopted, however, shall be designed to afford a claimant a full and fair review of his claim and shall comply with applicable regulations under ERISA.

8.9 Finality of Determinations; Exhaustion of Remedies. To the extent permitted by law, decisions reached under the claims procedures set forth in Section 8.8 shall be final and binding on all parties. No legal action for benefits under the Plan shall be brought unless and until the claimant has exhausted his remedies under Section 8.8. In any such legal action, the claimant may only present evidence and theories which the claimant presented during the claims procedure. Any claims which the claimant does not in good faith pursue through the review stage of the procedure shall be treated as having been irrevocably waived. Judicial review of a claimant's denied claim shall be limited to a determination of whether the denial was arbitrary, capricious or an abuse of discretion based on the evidence and theories the claimant presented during the claims procedure. This Section shall have no application during the 24-month period following a Change of Control as to a claim which is first asserted or first denied after the Change of Control and, as to such a claim, the de novo standard of judicial review shall apply. After the expiration of the 24-month period following a Change of Control, then, this Section shall again apply until the occurrence of a subsequent Change of Control.

8.10 Effect of Fiduciary Action. The Plan shall be interpreted by the Committee and all Plan fiduciaries in accordance with the terms of the Plan and their intended meanings. However, the Committee and all Plan fiduciaries shall have the discretion to make any findings of fact needed in the administration of the Plan, and shall have the discretion to interpret or construe ambiguous, unclear or implied (but omitted) terms in any fashion they deem to be appropriate in their sole judgment. Except as stated in Section 8.9, the validity of any such finding of fact, interpretation, construction or decision shall not be given de novo review if challenged in court, by arbitration or in any other forum, and shall be upheld unless clearly arbitrary or capricious. To the extent the Committee or any Plan fiduciary has been granted discretionary authority under the Plan, the Committee's or Plan fiduciary's prior exercise of such authority shall not obligate it to exercise its authority in a like fashion thereafter. If any Plan provision does not accurately reflect its intended meaning, as demonstrated by consistent interpretations or other evidence of intent, or as determined by the Committee in it sole and exclusive judgment, the provision shall be considered ambiguous and shall be interpreted by the Committee and all Plan fiduciaries in a fashion consistent with its intent, as determined by the Committee in its sole discretion. The Committee, without the need for Board's approval, may amend the Plan retroactively to cure any such ambiguity. This Section may not be invoked by any person to require the Plan to be interpreted in a manner which is inconsistent with its interpretation by the Committee or by any Plan fiduciaries. All actions taken and all determinations made in good faith by the Committee or by Plan fiduciaries shall be final and binding upon all persons claiming any interest in or under the Plan. This Section shall not apply to fiduciary or Committee actions or interpretations which take place or are made during the 24-month period following a Change of Control. After the expiration of the 24-month period following a Change of Control, then, this Section shall again apply until the occurrence of a subsequent Change of Control.

ARTICLE IX
GENERAL PROVISIONS

9.1 Effect on Other Plans. Deferred Amounts shall not be considered as part of a Participant's compensation for the purpose of any qualified defined contribution or defined benefit plan maintained by the Company, a Subsidiary or an Affiliated Entity in the Plan Year in which any deferral occurs under this Plan, and such amounts will not be considered under the Company's qualified defined contribution or defined benefit plans in the Plan Year in which payment occurs. However, such amounts may be taken into account under all other employee benefit plans maintained by the Company, a Subsidiary or an Affiliated Entity in the year in which such amounts would have been payable absent the deferral election; provided, such amounts shall not be taken into account if their inclusion would jeopardize the tax-qualified status of the plan to which they relate.

9.2 Conditions of Employment Not Affected by Plan. The establishment and maintenance of the Plan shall not be construed as conferring any legal rights upon any Participant to the continuation of employment with the Company, nor shall the Plan interfere with the rights of the Company to discharge any Participant with or without cause.

9.3 Restrictions on Alienation of Benefits. No right or benefit under this Plan shall be subject to anticipation, alienation, sale, assignment, pledge, encumbrance, or charge, and any attempt to anticipate, alienate, sell, assign, pledge, encumber, or charge the same shall be void. No right or benefit hereunder shall in any manner be liable for or subject to the debts, contracts, liabilities, or torts of the person entitled to such benefit. If any Participant or the Participant's Beneficiary under this Plan should become bankrupt or attempt to anticipate, alienate, sell, assign, pledge, encumber, or charge any right to a benefit hereunder, then, such right or benefit shall cease and terminate.

9.4 Funding. The benefits described in this Plan are obligations of the Employers to pay compensation for services, and shall constitute a liability to the Participants and/or their Beneficiaries in accordance with the terms hereof. All amounts paid under this Plan shall be paid in cash from the general assets of the Employers and shall be subject to the general creditors of the Company and the Employer of the Participant. Benefits shall be reflected on the accounting records of the Employers but shall not be construed to create, or require the creation of, a trust, custodial or escrow account. No Participant shall have any right, title or interest whatever in or to any investment reserves, accounts, funds or assets that the Employer may purchase, establish or accumulate to aid in providing the benefits described in this Plan. Nothing contained in this Plan, and no action taken pursuant to its provisions, shall create or be construed to create a trust or a fiduciary relationship of any kind between an Employer or the Company and a Participant or any other person. Provided, the Company may establish and/or continue the Trust. Neither a Participant nor the Beneficiary of a Participant shall acquire any interest hereunder greater than that of an unsecured creditor of the Company, a Subsidiary or any Affiliated Entity who is the Employer of such Participant.

9.5 Tax Consequences Not Guaranteed. The Company does not warrant that this Plan will have any particular tax consequences for Participants or Beneficiaries and shall not be liable to them if tax consequences they anticipate do not actually occur. The Company shall have no obligation to indemnify a Participant or Beneficiary for lost tax benefits (or other damage or loss) in the event the Plan is amended or terminated as permitted under Section 10.1, accelerated, or because of change in Plan design or funding; e.g., establishment of a "secular trust."

9.6 Construction. Except when otherwise indicated by the context, any masculine terminology when used in the Plan shall also include the feminine gender, and the definition of any term in the singular shall also include the plural.

9.7 Severability. If any provision of the Plan is held invalid or illegal for any reason, any illegality or invalidity shall not affect the remaining provisions of the Plan, and the Plan shall be construed and enforced as if the illegal or invalid provision had never been contained therein. The Company shall have the privilege and opportunity to correct and remedy such questions of illegality or invalidity by amendment.

9.8 Tax Withholding. The Employer may withhold from a payment or accrued benefit or from the Participant's other compensation any federal, state, or local taxes required by law to be withheld with respect to such payment or accrued benefit and such sums as the Employer may reasonably estimate as necessary to cover any taxes for which the Employer may be liable and which may be assessed with regard to Deferred Amounts or payments under this Plan.

9.9 Articles and Section Titles and Headings. The titles and headings at the beginning of each Article and Section shall not be considered in construing the meaning of any provisions in this Plan.

9.10 Governing Law. This Plan is subject to ERISA, but is exempt from most parts of ERISA since it is an unfunded deferred compensation plan maintained for a select group of management or highly compensated employees. In no event shall any references to ERISA in the Plan be construed to mean that the Plan is subject to any particular provisions of ERISA. The Plan shall be governed and construed in accordance with federal law and the laws of the State of Oklahoma, except to the extent such laws are preempted by ERISA.

ARTICLE X
AMENDMENT AND TERMINATION

10.1 Amendment and Termination. The Committee may amend, modify or terminate the Plan at any time and in any manner. No amendment may reduce the then vested Account balance of any Participant. In the event of a termination of the Plan, no further deferrals shall be made under the Plan. Amounts which are then payable or which become payable under the terms of the Plan shall be paid in a lump sum.

10.2 Change of Control. If a Change of Control occurs, the Plan shall terminate at the time of such event and the Participant Accounts shall be distributed in a lump sum unless the Committee elects to continue the Plan.

IN WITNESS WHEREOF, the Company and each Employer have caused this instrument to be executed by their duly authorized officers in a number of copies, each of which shall be deemed an original but all of which shall constitute one and the same instrument, this 3rd day of December, 2002, but effective as of January 1, 2003.

CHESAPEAKE ENERGY CORPORATION, an Oklahoma corporation

By: /s/ Martha A. Burger

Martha A. Burger, Treasurer and Senior Vice President - Human Resources

CHESAPEAKE ENERGY CORPORATION

DEFERRED COMPENSATION PLAN

CHESAPEAKE ENERGY CORPORATION
DEFERRED COMPENSATION PLAN

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CHESAPEAKE ENERGY CORPORATION
DEFERRED COMPENSATION PLAN

ARTICLE I
ESTABLISHMENT AND PURPOSE

1.1 Establishment. Chesapeake Energy Corporation ("Company"), hereby adopts the Chesapeake Energy Corporation Deferred Compensation Plan effective January 1, 2003.

1.2 Purpose. The Plan shall provide Eligible Employees and Directors the ability to defer payment of compensation earned and/or granted by the Company, its Subsidiaries and/or Affiliated Entities. The Plan is intended to provide such Eligible Employees and Directors with a degree of flexibility in their financial planning.

1.3 ERISA Status. The Plan is intended to qualify for the exemptions provided under Title I of ERISA for plans that are not tax-qualified and that are maintained primarily to provide deferred compensation for a select group of management or highly compensated employees as defined in Section 201(2) of ERISA.

ARTICLE II
DEFINITIONS

2.1 Definitions. For purposes of this Plan, the following definitions shall apply:

(a) "Account" means the recordkeeping accounts maintained in the name of a Participant to which Deferred Amounts, Company Discretionary Contributions and any income, earnings or losses thereon are recorded pursuant to the provisions of Article VII.

(b) "Affiliated Entity" means any partnership or limited liability company in which a majority of the partnership or other similar interest thereof is owned or controlled, directly or indirectly, by the Company or one or more of its Subsidiaries or Affiliated Entities or a combination thereof. For purposes hereof, the Company, a Subsidiary or an Affiliated Entity shall be deemed to have a majority ownership interest in a partnership or limited liability company if the Company, such Subsidiary or Affiliated Entity shall be allocated a majority of partnership or limited liability company gains or losses or shall be or control a managing director or a general partner of such partnership or limited liability company.

(c) "Base Salary" means the Participant's annualized gross rate of salary paid before any deductions of any kind whatsoever excluding overtime, bonuses, commissions and other extraordinary compensation.

(d) "Beneficiary" means the person, persons, trust, or other entity designated by a Participant on a beneficiary designation form adopted by the Committee to receive benefits, if any, under this Plan at such Participant's death pursuant to Section 6.4.

(e) "Board" means the Board of Directors of the Company.

(f) "Bonus" means the Participant's cash performance bonus(es) to be paid during each calendar year before any deductions of any kind whatsoever.

(g) "Change of Control" means the occurrence of any of the following:

(i) the acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 20% or more of either (A) the then outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (B) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors (the "Outstanding Company Voting Securities"). For purposes of this paragraph 2.1(g) the following acquisitions by a Person will not constitute a Change of Control: (1) any acquisition directly from the Company; (2) any acquisition by the Company; (3) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company; or (4) any acquisition by any corporation pursuant to a transaction which complies with clauses (A), (B) and (C) of paragraph (iii) below;

(ii) the individuals who, as of the date hereof, constitute the board of directors (the "Incumbent Board") cease for any reason to constitute at least a majority of the board of directors. Any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareholders, is approved by a vote of at least a majority of the directors then comprising the Incumbent Board will be considered a member of the Incumbent Board as of the date hereof, but any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Incumbent Board will not be deemed a member of the Incumbent Board as of the date hereof;

(iii) the consummation of a reorganization, merger, consolidation or sale or other disposition of all or substantially all of the assets of the Company (a "Business Combination"), unless following such Business Combination: (A) all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 60% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (B) no Person (excluding any corporation resulting from such Business Combination or any employee benefit plan (or related trust) of the Company or such corporation resulting from such Business Combination) beneficially owns, directly or indirectly, 20% or more of, respectively, the then outstanding shares of common stock of the corporation resulting from such Business Combination or the combined voting power of the then outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (C) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or

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

(h) "Code" means the Internal Revenue Code of 1986, as amended from time to time, and any Regulations relating thereto.

(i) "Committee" means the committee appointed by the Board of Directors of the Company to manage and administer the Plan.

(j) "Company Discretionary Contributions" means a discretionary contribution made by the Company to a Participant's Account pursuant to Article V of the Plan.

(k) "Deferred Amount" means the portion of a Participant's Base Salary and Bonus which the Participant elects to defer pursuant to Article IV. Deferred Amounts shall also include Director Fees which a Director elects to defer pursuant to Article IV. Deferred Amounts shall be determined by reference to the Plan Year in which the Base Salary or Director Fee is earned and the Plan Year in which the Bonus would otherwise have been paid.

(l) "Director" means a member of the Board of Directors of the Company who is not an employee of the Company.

(m) "Director Fee" means retainer, committee meeting fees or any other form of cash compensation payable by the Company to Directors as a result of their service on the Board.

(n) "Disability" means either a physical or mental disability as a result of which, at least 180 days after commencement of such disability, the Participant is determined, by a physician selected by the Company and acceptable to the Participant or the Participant's legal representative, to be totally and permanently disabled.

(o) "Election" means an affirmative election made by an Eligible Employee or Director on a deferral election form provided by the Committee with respect to which the Eligible Employee or Director may elect Deferred Amounts under this Plan.

(p) "Eligible Employee" means (i) an employee who (A) is designated by the Committee as belonging to a "select group of management or highly compensated employees," as such phrase is defined under ERISA; (B) receives a Base Salary of $100,000 or more during the twelve months immediately preceding the applicable Plan Year; and (C) is employed by the Company, a Subsidiary or an Affiliated Entity on December 31 preceding the applicable Plan Year; or (ii) an employee who is otherwise determined by the Committee to be eligible to participate in the Plan.

(q) "Employer" shall mean the Company and/or any Subsidiary or Affiliated Entity that employs a Participant.

(r) "ERISA" means the Employee Retirement Income Security Act of 1974, as amended.

(s) "Participant" means an Eligible Employee or Director who has Deferred Amounts credited to an Account under this Plan.

(t) "Plan" means this Chesapeake Energy Corporation Deferred Compensation Plan, as amended from time to time.

(u) "Plan Year" means the 12-month period beginning on January 1st and ending on December 31st.

(v) "Retirement Date" means the date a Participant is at least age 55 and performed at least 10 years of service with the Company, a Subsidiary or an Affiliated Entity.

(w) "Stock" means Chesapeake Energy Corporation common stock.

(x) "Subsidiary" shall have the same meaning set forth in Section 424 of the Code.

(y) "Trust" shall mean a "grantor trust" as defined in Section 671 of the Code, which may be established by the Company to provide a source of funding for amounts deferred hereunder.

(z) "Valuation Date" means the close of business on the applicable business day assuming daily valuation of Accounts.

ARTICLE III
ELIGIBILITY AND PARTICIPATION

The Committee shall provide Eligible Employees and Directors selected for participation in this Plan with notice of eligibility and permit such Eligible Employee or Director the opportunity to make an Election pursuant to Article IV. Notice may be given at the time and in the manner as the Committee may determine. All determinations regarding eligibility for participation in the Plan will be made by the Committee. The determinations of the Committee will be final and binding. Eligible Employees and Directors who have made an Election under this Plan shall continue as a Participant as long as there is a balance credited to his or her Account.

ARTICLE IV
ELECTIVE DEFERRALS

4.1 Eligible Employee Elective Deferrals. Eligible Employees may make elective deferrals with respect to the following sources in accordance with the provisions of this Article IV:

(a) Bonus. An Eligible Employee may elect to defer under this Plan and the Chesapeake Energy Corporation 401(k) Make-Up Plan up to 100% of the Eligible Employee's Bonus that may be awarded by the Company, a Subsidiary or an Affiliated Entity. The amount deferred shall be specified as a percentage of any Bonus which may be awarded to an Eligible Employee in a Plan Year.

(b) Base Salary. An Eligible Employee may elect to defer under this Plan and the Chesapeake Energy Corporation 401(k) Make-Up Plan up to 60% of the Eligible Employee's Base Salary as long as such deferral does not reduce such Eligible Employee's Base Salary below an amount necessary to satisfy applicable employment withholding tax obligations, benefit plan contributions, and income tax withholding obligations.

The minimum amount of Base Salary and Bonus that may be deferred under this Plan is $5,000.

4.2 Director Deferrals. A Director may elect to defer up to 100% of the Director Fees otherwise payable by the Company. The amount paid shall be specified as a percentage of the Directors Fees which may be paid in a Plan Year.

4.3 Timing of Deferral Election. Except as may be permitted by the Code or the regulations adopted thereunder, the Election to defer shall apply to Base Salary and Directors Fees earned and Bonus paid during the Plan Year which commences immediately following the year in which the Election is made. Elections must be completed and filed before the December 1 preceding the beginning of the Plan Year when such elections are to be applicable. Elections shall only be applicable to Base Salary which has not been earned, and to Bonus which has not been finally determined and/or awarded. Eligible Employees or Directors who are selected to participate in the Plan during a Plan Year will be permitted to participate in the Plan if an Election form is completed and filed at least 30 days prior to the date participation in the Plan is scheduled to commence. Elections will continue to apply to subsequent Plan Years unless and until the Participant files a revised Election with the Committee by December 1 of the year preceding the Plan Year when the revised Election is to be applicable.

ARTICLE V
COMPANY DISCRETIONARY CONTRIBUTIONS

The Committee may also make any contribution it so elects to a Participant in any given Plan Year.

ARTICLE VI
PAYMENT OF BENEFITS

6.1 Payment Upon Termination or Disability.

(a) Timing. Unless otherwise distributed in accordance with the terms of this Plan, payment of a Participant's vested Account shall commence as described below following (i) a Participant's termination of employment for any reason, or (ii) the date the Participant is determined by the Committee to have incurred a Disability.

(b) Installment Payments. If a Participant's vested Account balance is at least $50,000 and the Participant terminates employment or becomes Disabled after attaining the Participant's Retirement Date, the Participant is eligible to elect annual installment payments payable over a period of 1 to 20 years. The first installment shall commence within 30 days of the calendar quarter following the one-year anniversary of the Participant's date of termination or date of Disability with each subsequent annual installment paid in January of each year until all installment payments have been paid. If a Participant qualifies for an installment payment but fails to make an effective designation as to method of payment, the Participant's Account will be distributed in annual installments over 10 years.

(c) Lump Sum Payment. If a Participant terminates employment for any reason prior to his or her Retirement Date or with an Account balance less than $50,000, payment will be made in the form of a lump sum within 30 days following the month of the Participant's date of termination or Disability. If a Participant terminates employment or becomes Disabled and is eligible to receive installment payments but elects to receive payment in the form of a single lump sum, payment will be made 13 months following the Participant's date of termination or date of Disability. If a Participant is a Director, payment will be made in the form of a lump sum within 30 days following the month of termination of service to the Company.

(d) Changes in Method of Payment. The Committee, in its sole discretion, may permit a different method of payment if a Participant is determined by the Committee to be subject to special circumstances. The method of payment may be changed from time to time by the Participant, but in no event will such change be considered valid if the change occurs within the 12-month period prior to the date payment is scheduled to commence without the approval of the Committee.

6.2 Scheduled In-Service Withdrawal. A Participant may schedule distribution of the Deferred Amounts attributable to a particular Plan Year ("Scheduled In-Service Withdrawal") to commence in January at least two years after the end of the Plan Year in which deferrals were made. Participants must request a Scheduled In-Service Withdrawal on the deferral election form that is submitted for that Plan Year. If a Participant fails to elect a Scheduled In-Service Withdrawal prior to the date deferrals begin for that Plan Year, that Participant will not be eligible to obtain a Scheduled In-Service Withdrawal for deferrals made in such Plan Year.

(a) Payment Method. The Participant may elect either a lump sum payment or, if the distribution requested is at least $25,000, annual installment payments for a period of 2 to 10 years.

(b) Postponement. A Participant may postpone payment of a Scheduled In-Service Withdrawal to a date at least one year later than the previously Scheduled In-Service Withdrawal date by filing a written request with the Committee at least one year prior to the date the Scheduled In-Service Withdrawal is scheduled to begin.

(c) Cancellation. If the Participant terminates employment or is determined by the Committee to have incurred a Disability, payment of the Participant's Account shall be determined with respect to elections made in reference to termination in accordance with Section

6.1, without regard to the otherwise Scheduled In-Service Withdrawal which shall be deemed to be cancelled.

6.3 Payment to Beneficiary. If a Participant dies with a vested balance credited to the Participant's Account, such balance shall be paid to the Participant's Beneficiary in a lump sum.

6.4 Beneficiary Designations. A Participant shall designate on a beneficiary designation form provided by the Committee a Beneficiary who, upon the Participant's death, will receive payments that otherwise would have been paid to the Participant under the Plan. All Beneficiary designations must be in writing. Beneficiary designations will be effective only if and when delivered to the Committee during the lifetime of the Participant. A Participant may change a Beneficiary or Beneficiaries by filing a new beneficiary designation form. The latest beneficiary designation form shall apply to the Account of the Participant. If a Beneficiary of a Participant predeceases the Participant, the designation of such Beneficiary shall be void. If a Beneficiary to whom benefits under the Plan remain unpaid dies after the Participant and the Participant failed to specify a contingent Beneficiary on the appropriate Beneficiary designation form, the balance of the Participant's Account will be paid to such Beneficiary's estate. If a Participant fails to designate a Beneficiary or if such designation is ineffective, in whole or in part, any payment that otherwise would have been paid to such Participant shall be paid to the Participant's estate.

6.5 Changes in Payment Date.

(a) Emergency. If the Participant experiences an unforeseeable emergency, payment of the Participant's Account attributable to Deferred Amounts, prior to the Participant's termination date may occur with the approval of the Committee subject to the following conditions:

(i) The minimum emergency withdrawal is the lesser of $25,000 or 100% of the Account balance;

(ii) The Participant must submit a written request to the Committee at least 30 days prior to the date the Participant requests payment. The written notice must state the reason necessitating the early payment and provide documentation that the financial hardship cannot be satisfied by other assets;

(iii) The emergency must result from a severe financial hardship to the Participant resulting from (1) a sudden and unexpected illness or accident of the Participant or of a dependent (as defined in Section 152(a) of the Code) of the Participant, (2) loss of the Participant's property due to casualty, or (3) other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant. The need to send a Participant's child to college or the desire to purchase a home shall not be considered emergencies for purposes of this Subsection 6.5(a);

(iv) The decision whether to allow an emergency withdrawal from the Participant's Account shall be made in the sole and absolute discretion of the Committee; and

(v) In the event a Participant receives an emergency payment, all deferrals elected for such Plan Year shall cease, and the Participant shall not be eligible to participate in the Plan for the balance of the Plan Year and one additional Plan Year.

(b) Nonscheduled Withdrawal. A Participant may request an unscheduled distribution of not less than 25% of the portion of his Account attributable to Deferred Amounts. However, the distribution will be subject to a 10% penalty of the amount requested. In the event a Participant requests a nonscheduled withdrawal, (i) all deferrals under this Plan for such Plan Year shall cease, (ii) the Participant shall not be eligible to participate in the Plan for the balance of the Plan Year and one additional Plan Year, and (iii) the Participant shall forfeit the portion of Company Discretionary Contributions (vested and unvested) held in the Participant's Account in proportion to the Deferred Amounts distributed to the Participant.

ARTICLE VII
ACCOUNTS AND INVESTMENT

7.1 Establishment of Account. There shall be established and maintained by the Company a separate Account in the name of each Participant who has elected to defer Base Salary or Bonus under the terms of this Plan.

7.2 Balance of Account. The balance of each Participant's Account shall include Deferred Amounts and any Company Discretionary Contributions plus income and gains credited with respect to the deemed investments selected by the Participant based on the benchmark funds provided by the Committee. Losses from the deemed investments shall reduce the Participant's Account balance. The balance of each Participant's Account shall be determined as of each Valuation Date.

7.3 Investment Direction - Deferred Amounts. The Committee may, in its sole discretion, offer more than one benchmark fund as a deemed investment alternative. If the Committee elects to offer more than one deemed investment alternative, on such form as the Committee prescribes, each Participant may select among the different benchmark funds for Deferred Amounts. However, the Committee is not required to accept the deemed investments made by the Participant. No actual investments shall be made by Participants. The deemed investments in benchmark funds are only for the purpose of determining the Company's payment obligation under the Plan. A Participant who has a choice of more than one such benchmark fund may, as frequently as daily, modify his deemed investment election of benchmark funds through a procedure designated by the Committee. Such modification will be in accordance with rules and procedures adopted by the Committee. The balance of each Participant's Account shall be deemed invested in one or more benchmark funds on each Valuation Date, and income or losses shall accrue on such balance upon such date, from the previous Valuation Date.

7.4 Investment of Company Contributions. The Committee will determine how Company Discretionary Contributions will be invested. A Participant may not elect to diversify the portion of his Account attributable to Company Discretionary Contributions. If the Committee determines that a Company Discretionary Contribution will be invested in Stock, on the last day of the applicable calendar quarter the Company shall transfer to the trustee of the Trust cash equal to the amount of the Company Discretionary Contribution for the quarter. The trustee shall purchase shares of Stock on the open market on the last business day of each calendar quarter. Shares of Stock shall be issued in the name of the trustee of the Trust. During the period that Stock is held by the trustee, cash dividends will not be paid with respect to such Stock and Stock dividends will not be reinvested in the Participant's Account. During the period Stock is held by the Trust, Participants will not have the right to vote such shares of Stock and the Participant will not have any other incidents of ownership or rights as a shareholder with respect to such Stock. Distributions of the Participant's Account balance attributable to Company Discretionary Contributions that were initially invested in Stock will be made in Stock.

7.5 Vesting.

(a) Deferred Amounts. Subject to the conditions and limitations on payment of benefits under the Plan, a Participant shall always have a fully vested and nonforfeitable beneficial interest in the balance standing to the credit of the Participant's Account attributable to Deferred Amounts and income, earnings or losses thereon.

(b) Company Discretionary Contributions. Company Discretionary Contributions shall vest as determined by the Committee upon the grant of a Company Discretionary Contribution. If a Participant terminates employment prior to vesting, the unvested Company Discretionary Contributions and any income, earnings or losses thereon shall be forfeited. Forfeited amounts shall be used to offset future contributions by the Company. In the event termination is due to death, Disability or retirement, the Committee may, in its sole and absolute discretion, accelerate vesting. The Committee may also, in its sole and absolute discretion, accelerate vesting upon termination for any reason. Upon the occurrence of a Change of Control, all Participants shall be deemed to be 100% vested in all Company Discretionary Contributions credited to their Account.

7.6 Account Statements. The Committee shall provide each Participant with a statement of the status of the Participant's Account under the Plan. The Committee shall provide such statement quarterly or at such times as the Committee may determine. Account statements shall be in the format prescribed by the Committee.

ARTICLE VIII
ADMINISTRATION

8.1 Administration. The Plan shall be administered, construed and interpreted by the Committee. The Committee shall have the sole authority and discretion to determine eligibility for benefits and to construe the terms of the Plan. The determinations by the Committee as to any disputed questions arising under the Plan, including the eligibility to become a Participant in the Plan and the amounts of benefits under the Plan, and the construction and interpretation by the Committee of any provision of the Plan, shall be final, conclusive and binding upon all persons including Participants, their beneficiaries, the Company, its stockholders and employees and the Employers.

8.2 Indemnification and Exculpation. The members of the Committee and its agents shall be indemnified and held harmless by the Company against and from any and all loss, cost, liability or expense that may be imposed upon or reasonably incurred by them in connection with or resulting from any claim, action, suit or proceeding to which they may be a party or in which they may be involved by reason of any action taken or failure to act under this Plan and against and from any and all amounts paid by them in settlement (with the Company's written approval) or paid by them in satisfaction of a judgment in any such action, suit or proceeding. The foregoing provisions shall not be applicable to any person if the loss, cost, liability or expense is due to such person's gross negligence or willful misconduct.

8.3 Rules of Conduct. The Committee shall adopt rules for the conduct of its business and the administration of this Plan as it considers desirable, provided they do not conflict with the provisions of this Plan.

8.4 Legal, Accounting, Clerical and Other Services. The Committee may authorize one or more of its members or any agent to act on its behalf and may contract for legal, accounting, clerical and other services to carry out this Plan. The Company shall pay all expenses of the Committee.

8.5 Records of Administration. The Committee shall keep or designate another party to keep records reflecting the administration of this Plan which shall be subject to audit by the Company.

8.6 Expenses. The expenses of administering the Plan shall be borne by the Company.

8.7 Liability. No member of the Board or of the Committee shall be liable for any act or action, whether of commission or omission, taken by any other member, or by any officer, agent, or employee of the Company or of any such body, nor, except in circumstances involving his bad faith, for anything done or omitted to be done by himself.

8.8 Claims Review Procedures. The following claim procedures shall apply until such time as a Change of Control has occurred. During the 24-month period following a Change of Control, these procedures shall apply only to the extent the claimant requests their application. After the expiration of the 24-month period following a Change of Control, then, these procedures shall again apply until the occurrence of a subsequent Change of Control.

(a) Denial of Claim. If a claim for benefits is wholly or partially denied, the claimant shall be given notice in writing of the denial within a reasonable time after the receipt of the claim, but not later than 90 days after the receipt of the claim. However, if special circumstances require an extension, written notice of the extension shall be furnished to the claimant before the termination of the 90-day period. In no event shall the extension exceed a period of 90 days after the expiration of the initial 90-day period. The notice of the denial shall contain the following information written in a manner that may be understood by a claimant:

(i) The specific reasons for the denial;

(ii) Specific reference to pertinent Plan provisions on which the denial is based;

(iii) A description of any additional material or information necessary for the claimant to perfect his claim and an explanation of why such material or information is necessary;

(iv) An explanation that a full and fair review by the Committee of the denial may be requested by the claimant or his authorized representative by filing a written request for a review with the Committee within 60 days after the notice of the denial is received; and

(v) If a request for review is filed, the claimant or his authorized representative may review pertinent documents and submit issues and comments in writing within the 60-day period described in Section 8.8(a)(iv).

(b) Decisions After Review. The decision of the Committee with respect to the review of the denial shall be made promptly and in writing, but not later than 60 days after the Committee receives the request for the review. However, if special circumstances require an extension of time, a decision shall be rendered not later than 120 days after the receipt of the request for review. A written notice of the extension shall be furnished to the claimant prior to the expiration of the initial 60-day period. The claimant shall be given a copy of the decision, which shall state, in a manner calculated to be understood by the claimant, the specific reasons for the decision and specific references to the pertinent Plan provisions on which the decision is based.

(c) Other Procedures. Notwithstanding the foregoing, the Committee may, in its discretion, adopt different procedures for different claims without being bound by past actions. Any procedures adopted, however, shall be designed to afford a claimant a full and fair review of his claim and shall comply with applicable regulations under ERISA.

8.9 Finality of Determinations; Exhaustion of Remedies. To the extent permitted by law, decisions reached under the claims procedures set forth in Section 8.8 shall be final and binding on all parties. No legal action for benefits under the Plan shall be brought unless and until the claimant has exhausted his remedies under Section 8.8. In any such legal action, the claimant may only present evidence and theories which the claimant presented during the claims procedure. Any claims which the claimant does not in good faith pursue through the review stage of the procedure shall be treated as having been irrevocably waived. Judicial review of a claimant's denied claim shall be limited to a determination of whether the denial was arbitrary, capricious or an abuse of discretion based on the evidence and theories the claimant presented during the claims procedure. This Section shall have no application during the 24-month period following a Change of Control as to a claim which is first asserted or first denied after the Change of Control and, as to such a claim, the de novo standard of judicial review shall apply. After the expiration of the 24-month period following a Change of Control, then, this Section shall again apply until the occurrence of a subsequent Change of Control.

8.10 Effect of Fiduciary Action. The Plan shall be interpreted by the Committee and all Plan fiduciaries in accordance with the terms of the Plan and their intended meanings. However, the Committee and all Plan fiduciaries shall have the discretion to make any findings of fact needed in the administration of the Plan, and shall have the discretion to interpret or construe ambiguous, unclear or implied (but omitted) terms in any fashion they deem to be appropriate in their sole judgment. Except as stated in Section 8.9, the validity of any such finding of fact, interpretation, construction or decision shall not be given de novo review if challenged in court, by arbitration or in any other forum, and shall be upheld unless clearly arbitrary or capricious. To the extent the Committee or any Plan fiduciary has been granted discretionary authority under the Plan, the Committee's or Plan fiduciary's prior exercise of such authority shall not obligate it to exercise its authority in a like fashion thereafter. If any Plan provision does not accurately reflect its intended meaning, as demonstrated by consistent interpretations or other evidence of intent, or as determined by the Committee in it sole and exclusive judgment, the provision shall be considered ambiguous and shall be interpreted by the Committee and all Plan fiduciaries in a fashion consistent with its intent, as determined by the Committee in its sole discretion. The Committee, without the need for Board's approval, may amend the Plan retroactively to cure any such ambiguity. This Section may not be invoked by any person to require the Plan to be interpreted in a manner which is inconsistent with its interpretation by the Committee or by any Plan fiduciaries. All actions taken and all determinations made in good faith by the Committee or by Plan fiduciaries shall be final and binding upon all persons claiming any interest in or under the Plan. This Section shall not apply to fiduciary or Committee actions or interpretations which take place or are made during the 24-month period following a Change of Control. After the expiration of the 24-month period following a Change of Control, then, this Section shall again apply until the occurrence of a subsequent Change of Control.

ARTICLE IX
GENERAL PROVISIONS

9.1 Effect on Other Plans. Deferred Amounts shall not be considered as part of a Participant's compensation for the purpose of any qualified defined contribution or defined benefit plan maintained by the Company, a Subsidiary or an Affiliated Entity in the Plan Year in which any deferral occurs under this Plan, and such amounts will not be considered under the Company's qualified defined contribution or defined benefit plans in the Plan Year in which payment occurs. However, such amounts may be taken into account under all other employee benefit plans maintained by the Company, a Subsidiary or an Affiliated Entity in the year in which such amounts would have been payable absent the deferral election; provided, such amounts shall not be taken into account if their inclusion would jeopardize the tax-qualified status of the plan to which they relate.

9.2 Conditions of Employment Not Affected by Plan. The establishment and maintenance of the Plan shall not be construed as conferring any legal rights upon any Participant to the continuation of employment with the Company, nor shall the Plan interfere with the rights of the Company to discharge any Participant with or without cause.

9.3 Restrictions on Alienation of Benefits. No right or benefit under this Plan shall be subject to anticipation, alienation, sale, assignment, pledge, encumbrance, or charge, and any attempt to anticipate, alienate, sell, assign, pledge, encumber, or charge the same shall be void. No right or benefit hereunder shall in any manner be liable for or subject to the debts, contracts, liabilities, or torts of the person entitled to such benefit. If any Participant or the Participant's Beneficiary under this Plan should become bankrupt or attempt to anticipate, alienate, sell, assign, pledge, encumber, or charge any right to a benefit hereunder, then, such right or benefit shall cease and terminate.

9.4 Funding. The benefits described in this Plan are obligations of the Employers to pay compensation for services, and shall constitute a liability to the Participants and/or their Beneficiaries in accordance with the terms hereof. All amounts paid under this Plan shall be paid in cash from the general assets of the Employers and shall be subject to the general creditors of the Company and the Employer of the Participant. Benefits shall be reflected on the accounting records of the Employers but shall not be construed to create, or require the creation of, a trust, custodial or escrow account. No Participant shall have any right, title or interest whatever in or to any investment reserves, accounts, funds or assets that the Employer may purchase, establish or accumulate to aid in providing the benefits described in this Plan. Nothing contained in this Plan, and no action taken pursuant to its provisions, shall create or be construed to create a trust or a fiduciary relationship of any kind between an Employer or the Company and a Participant or any other person. Provided, the Company may establish and/or continue the Trust. Neither a Participant nor the Beneficiary of a Participant shall acquire any interest hereunder greater than that of an unsecured creditor of the Company, a Subsidiary or any Affiliated Entity who is the Employer of such Participant.

9.5 Construction. Except when otherwise indicated by the context, any masculine terminology when used in the Plan shall also include the feminine gender, and the definition of any term in the singular shall also include the plural.

9.6 Severability. If any provision of the Plan is held invalid or illegal for any reason, any illegality or invalidity shall not affect the remaining provisions of the Plan, and the Plan shall be construed and enforced as if the illegal or invalid provision had never been contained therein. The Company shall have the privilege and opportunity to correct and remedy such questions of illegality or invalidity by amendment.

9.7 Tax Consequences Not Guaranteed. The Company does not warrant that this Plan will have any particular tax consequences for Participants or Beneficiaries and shall not be liable to them if tax consequences they anticipate do not actually occur. The Company shall have no obligation to indemnify a Participant or Beneficiary for lost tax benefits (or other damage or loss) in the event the Plan is amended or terminated as permitted under Section 10.1, accelerated, or because of change in Plan design or funding; e.g., establishment of a "secular trust."

9.8 Tax Withholding. The Employer may withhold from a payment or accrued benefit or from the Participant's other compensation any federal, state, or local taxes required by law to be withheld with respect to such payment or accrued benefit and such sums as the Employer may reasonably estimate as necessary to cover any taxes for which the Employer may be liable and which may be assessed with regard to Deferred Amounts or payments under this Plan.

9.9 Articles and Section Titles and Headings. The titles and headings at the beginning of each Article and Section shall not be considered in construing the meaning of any provisions in this Plan.

9.10 Governing Law. This Plan is subject to ERISA, but is exempt from most parts of ERISA since it is an unfunded deferred compensation plan maintained for a select group of management or highly compensated employees. In no event shall any references to ERISA in the Plan be construed to mean that the Plan is subject to any particular provisions of ERISA. The Plan shall be governed and construed in accordance with federal law and the laws of the State of Oklahoma, except to the extent such laws are preempted by ERISA.

ARTICLE X
AMENDMENT AND TERMINATION

10.1 Amendment and Termination. The Committee may amend, modify or terminate the Plan at any time and in any manner. No amendment may reduce the then vested Account balance of any Participant. In the event of a termination of the Plan, no further deferrals shall be made under the Plan. Amounts which are then payable or which become payable under the terms of the Plan shall be paid in a lump sum.

10.2 Change of Control. If a Change of Control occurs, the Plan shall terminate at the time of such event and the Participant Accounts will be distributed in a lump sum unless the Committee elects to continue the Plan.

IN WITNESS WHEREOF, the Company and each Employer have caused this instrument to be executed by their duly authorized officers in a number of copies, each of which shall be deemed an original but all of which shall constitute one and the same instrument, this 3rd day of December, 2002, but effective as of January 1, 2003.

CHESAPEAKE ENERGY CORPORATION, an
Oklahoma corporation

By: /s/ Martha A. Burger

Martha A. Burger, Treasurer and Senior Vice
President - Human Resources

Exhibit 12

CHESAPEAKE ENERGY CORPORATION
RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS
(dollars in 000's)

	Year Ended June 30, 1997	Six Months Ended Dec. 31, 1997	Year Ended Dec. 31, 1998	Year Ended Dec. 31, 1999	Year Ended Dec. 31, 2000	Year Ended Dec. 31, 2001	Year Ended Dec. 31, 2002
Income before income taxes and extraordinary item	$ (180,330)	$ (31,574)	$ (920,520)	$ 35,030	$ 196,162	$ 438,365	$ 67,140
Interest	18,550	17,448	68,249	81,052	86,256	98,321	111,280
Amortization of capitalized interest	8,772	4,386	12,240	1,047	1,226	1,784	1,804
Bond discount amortization (a)	-	-	-	-	-	-	-
Loan cost amortization	1,455	794	2,516	3,338	3,669	4,022	4,962
Earnings	$ (151,553)	$ (8,946)	$ (837,515)	$ 120,467	$ 287,313	$ 542,492	$ 185,186
Interest expense	$ 18,550	$ 17,448	$ 68,249	$ 81,052	$ 86,256	$ 98,321	$ 111,280
Capitalized interest	12,935	5,087	6,470	3,356	2,452	4,719	4,976
Bond discount amortization (a)	-	-	-	-	-	-	-
Loan cost amortization	1,455	794	2,516	3,338	3,669	4,022	4,962
Fixed Charges	$ 32,940	$ 23,329	$ 77,235	$ 87,746	$ 92,377	$ 107,062	$ 121,218
Preferred Stock Dividends							
Preferred Dividend Requirements	$ -	$ -	$ 12,077	$ 16,711	$ 8,484	$ 2,050	$ 10,117
Ratio of income before provision for taxes to Net Income (b)	-	-	N/A	1.05	N/A	1.66	1.67
Subtotal - Preferred Dividends	$ -	$ -	$ 12,077	$ 17,597	$ 8,484	$ 3,411	$ 16,861
Combined Fixed Charges and Preferred Dividends	$ 32,940	$ 23,329	$ 89,312	$ 105,343	$ 100,861	$ 110,473	$ 138,079
Ratio of Earnings to Fixed Charges	-	-	-	1.4	3.1	5.1	1.5
Insufficient coverage	$ 184,493	$ 32,275	$ 914,750	$ -	$ -	$ -	$ -
Ratio of Earnings to Combined Fixed Charges and Preferred Dividends	-	-	-	1.1	2.8	4.9	1.3
Insufficient coverage	$ 184,493	$ 32,275	$ 926,827	$ -	$ -	$ -	$ -

(a) Bond discount excluded since its included in interest expense
(b) Represents income (loss) before income taxes and extraordinary item divided by income (loss) before extraordinary item, which adjusts dividends on preferred stock to a pre-tax basis.

EXHIBIT 21

SUBSIDIARIES OF CHESAPEAKE ENERGY CORPORATION

CORPORATIONS AND LIMITED LIABILITY COMPANIES	STATE OF ORGANIZATION
The Ames Company, L.L.C.	Oklahoma
Carmen Acquisition, L.L.C.	Oklahoma
Chesapeake Acquisition, L.L.C.	Oklahoma
Chesapeake Energy Louisiana Corporation	Oklahoma
Chesapeake Energy Marketing, Inc.	Oklahoma
Chesapeake Mountain Front, L.L.C.	Oklahoma
Chesapeake Operating, Inc.	Oklahoma
Chesapeake Royalty, L.L.C.	Oklahoma
Gothic Energy, L.L.C.	Oklahoma
Gothic Production, L.L.C.	Oklahoma
Nomac Drilling Corporation	Oklahoma
Sap Acquisition, L.L.C.	Oklahoma
Chesapeake KNAN Acquisition, L.L.C.	Oklahoma
Chesapeake ENO Acquisition Corp.	Oklahoma
Chesapeake Beta Corp.	Oklahoma
Chesapeake Delta Corp.	Oklahoma
Chesapeake Focus, L.L.C.	Oklahoma
Chesapeake OKC, L.L.C.	Oklahoma
PARTNERSHIPS	
Chesapeake Exploration Limited Partnership	Oklahoma
Chesapeake Louisiana, L.P.	Oklahoma
Chesapeake Panhandle Limited Partnership	Oklahoma
Chesapeake-Staghorn Acquisition L.P.	Oklahoma
Chesapeake Sigma, L.P.	Oklahoma

EXHIBIT 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (File Nos. 33-84256, 33-84258, 33-89282, 33-88196, 333-27525, 333-07255, 333-30324, 333-46129, 333-30478, 333-52666, 333-52668, 333-67734, 333-67736, and 333-67740), Form S-3 (File Nos. 333-41014, 333-61508, 333-76546 and 333-96863) and Form S-4 (File Nos. 333-99289, 333-102445 and 333-102446) of Chesapeake Energy Corporation of our report dated February 24, 2003 relating to the consolidated financial statements and financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
February 26, 2003

EXHIBIT 23.2

CONSENT OF WILLIAMSON PETROLEUM CONSULTANTS, INC.

As independent oil and gas consultants, Williamson Petroleum Consultants, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-84256, 33-84258, 33-89282, 33-88196, 333-27525, 333-07255, 333-30324, 333-46129, 333-30478, 333-52666, 333-52668, 333-67734, 333-67736, and 333-67740), Form S-3 (File Nos. 333-41014, 333-61508, 333-76546 and 333-96863) and Form S-4 (File Nos. 333-99289, 333-102445 and 333-102446) of Chesapeake Energy Corporation of information from our reserve report dated February 21, 2003 entitled "Evaluation of Oil and Gas Reserves to the Interests of Chesapeake Energy Corporation in Certain Major-Value Properties in the United States, Effective December 31, 2002, for Disclosure to the Securities and Exchange Commission, Williamson Project 2.8923" and all references to our firm included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K which was filed with the Securities and Exchange Commission on February 26, 2003.

Williamson Petroleum Consultants, Inc.
Midland, TX
February 26, 2003

EXHIBIT 23.3

CONSENT OF RYDER SCOTT COMPANY PETROLEUM CONSULTANTS L.P.

As independent oil and gas consultants, Ryder Scott Company, L.P. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-84256, 33-84258, 33-89282, 33-88196, 333-27525, 333-07255, 333-30324, 333-46129, 333-30478, 333-52666, 333-52668, 333-67734, 333-67736, and 333-67740), Form S-3 (File Nos. 333-41014, 333-61508, 333-76546 and 333-96863) and Form S-4 (File Nos. 333-99289, 333-102445 and 333-102446) of Chesapeake Energy Corporation of information from our reserve report dated February 25, 2003 entitled "Chesapeake Energy Corporation--Estimated Future Reserves and Income Attributable to Certain Leasehold Interests (SEC Parameters) as of December 31, 2002" and all references to our firm included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K which was filed with the Securities and Exchange Commission on February 26, 2003.

Ryder Scott Company, L.P.
Houston, TX
February 26, 2003

EXHIBIT 23.4

CONSENT OF LEE KEELING AND ASSOCIATES, INC.

As independent oil and gas consultants, Lee Keeling and Associates, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-84256, 33-84258, 33-89282, 33-88196, 333-27525, 333-07255, 333-30324, 333-46129, 333-30478, 333-52666, 333-52668, 333-67734, 333-67736, and 333-67740), Form S-3 (File Nos. 333-41014, 333-61508, 333-76546 and 333-96863) and Form S-4 (File Nos. 333-99289, 333-102445 and 333-102446) of Chesapeake Energy Corporation of information from our reserve report dated February 21, 2003 entitled "Appraisal Oil and Gas Properties Interests Owned by Chesapeake Energy Corporation Selected Properties Constant Prices and Expenses Effective Date January 1, 2003" and all references to our firm included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K which was filed with the Securities and Exchange Commission on February 26, 2003.

Lee Keeling and Associates, Inc.
Tulsa, Oklahoma
February 25, 2003

EXHIBIT 23.5

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent oil and gas consultants, Netherland, Sewell & Associates, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-84256, 33-84258, 33-89282, 33-88196, 333-27525, 333-07255, 333-30324, 333-46129, 333-30478, 333-52666, 333-52668, 333-67734, 333-67736, and 333-67740), Form S-3 (File Nos. 333-41014, 333-61508, 333-76546 and 333-96863) and Form S-4 (File Nos. 333-99289, 333-102445 and 333-102446) of Chesapeake Energy Corporation of information from our reserve report dated on or about March 7, 2003 entitled "Estimate of Reserves and Future Revenue to the Chesapeake Energy Corporation Interest in Certain Oil and Gas Properties located in the United States as of December 31, 2002, Based on Constant Prices and Costs in accordance with Securities and Exchange Commission Guidelines" and all references to our firm included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K which was filed with the Securities and Exchange Commission on or about February 26, 2003.

Netherland, Sewell & Associates, Inc.
Dallas, TX
February 26, 2003

EXHIBIT 99.1

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 year ended December 31, 2002 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 (S) 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: February 26, 2003

EXHIBIT 99.2

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 year ended December 31, 2002 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 (S) 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: February 26, 2003