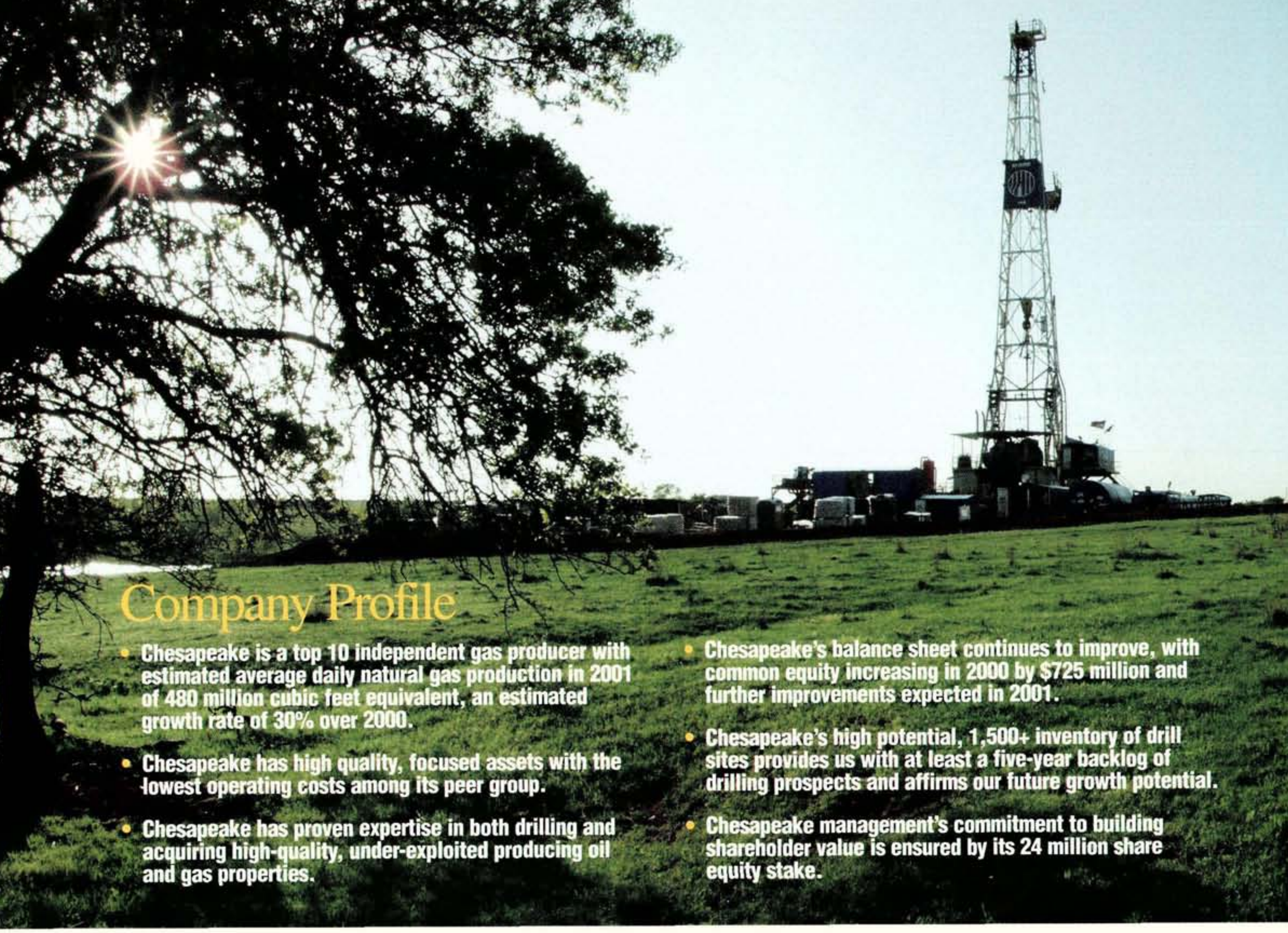
Chesapeake

Natural Gas.
Natural Advantages.

2000 Annual Report



Company Profile

- Chesapeake is a top 10 independent gas producer with estimated average daily natural gas production in 2001 of 480 million cubic feet equivalent, an estimated growth rate of 30% over 2000.
- Chesapeake has high quality, focused assets with the lowest operating costs among its peer group.
- Chesapeake has proven expertise in both drilling and acquiring high-quality, under-exploited producing oil and gas properties.
- Chesapeake's balance sheet continues to improve, with common equity increasing in 2000 by $725 million and further improvements expected in 2001.
- Chesapeake's high potential, 1,500+ inventory of drill sites provides us with at least a five-year backlog of drilling prospects and affirms our future growth potential.
- Chesapeake management's commitment to building shareholder value is ensured by its 24 million share equity stake.

Table of Contents

Chesapeake's New Logo

To most of our shareholders our 2000 Annual Report introduces Chesapeake's new logo "Natural Gas, Natural Advantages" for the first time. These words convey the simple but powerful twin components of our image and message – natural gas and Chesapeake enjoy many natural advantages over other fuels and other companies.

One other thought about our Annual Report covers over the years – we hope you'll notice our basic message doesn't change very much. On our first six annual report covers, we used images involving drilling rigs to convey our message that Chesapeake was one of the top growth-through-the-drillbit companies in the industry. In 1998, we strategically shifted away from our reliance on growing exclusively through higher-risk drilling and from our desire to find both oil and natural gas to today's strategy focused on developing natural gas reserves through balanced drilling and acquisitions.

Chesapeake
Natural Gas.
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Selected Financial Data

	Year Ended December 31,				Six Months Ended December 31,		Year Ended June 30,
	2000	**1999**	**1998**	**1997**	**1997**	**1996**	**1997**
Operations Data				*Unaudited*		*Unaudited*	
(***$ in thousands, except per share data***)							
Oil and gas sales	**$ 470,170**	$ 280,445	$ 256,887	$ 198,410	$ 95,657	$ 90,167	$ 192,920
Oil and gas marketing sales	**157,782**	74,501	121,059	104,394	58,241	30,019	76,172
Total revenues	**627,952**	354,946	377,946	302,804	153,898	120,186	269,092
Production expenses	**50,085**	46,298	51,202	14,737	7,560	4,268	11,445
Production taxes	**24,840**	13,264	8,295	4,590	2,534	1,606	3,662
General and administrative	**13,177**	13,477	19,918	10,910	5,847	3,739	8,802
Oil and gas marketing expenses	**152,309**	71,533	119,008	103,819	58,227	29,548	75,140
Oil and gas depreciation, depletion and amortization	**101,291**	95,044	146,644	127,429	60,408	36,243	103,264
Depreciation and amortization of other assets	**7,481**	7,810	8,076	4,360	2,414	1,836	3,782
Impairment of oil and gas properties	**—**	—	826,000	346,000	110,000	—	236,000
Impairment of other assets	**—**	—	55,000	—	—	—	—
Total operating costs	**349,183**	247,426	1,234,143	611,845	246,990	77,240	442,095
Income (loss) from operations	**278,769**	107,520	(856,197)	(309,041)	(93,092)	42,946	(173,003)
Other income (expense):							
Interest and other income	**3,649**	8,562	3,926	87,673	78,966	2,516	11,223
Interest expense	**(86,256)**	(81,052)	(68,249)	(29,782)	(17,448)	(6,216)	(18,550)
Total other income (expense)	**(82,607)**	(72,490)	(64,323)	57,891	61,518	(3,700)	(7,327)
Income (loss) before income taxes and extraordinary item	**196,162**	35,030	(920,520)	(251,150)	(31,574)	39,246	(180,330)
Provision (benefit) for income taxes	**(259,408)**	1,764	—	(17,898)	—	14,325	(3,573)
Income (loss) before extraordinary item	**455,570**	33,266	(920,520)	(233,252)	(31,574)	24,921	(176,757)
Extraordinary item:							
Loss on early extinguishment of debt, net of applicable income taxes	**—**	—	(13,334)	(177)	—	(6,443)	(6,620)
Net income (loss)	**455,570**	33,266	(933,854)	(233,429)	(31,574)	18,478	(183,377)
Preferred stock dividends	**(8,484)**	(16,711)	(12,077)	—	—	—	—
Gain on redemption of preferred stock	**6,574**	—	—	—	—	—	—
Net income (loss) available to common shareholders	**$ 453,660**	$ 16,555	$ (945,931)	$ (233,429)	$ (31,574)	$ 18,478	$ (183,377)
Earnings (loss) per common share – basic:							
Income (loss) before extraordinary item	**$ 3.52**	$ 0.17	$ (9.83)	$ (3.30)	$ (0.45)	$ 0.40	$ (2.69)
Extraordinary item	**—**	—	(0.14)	—	—	(0.10)	(0.10)
Net income (loss)	**$ 3.52**	$ 0.17	$ (9.97)	$ (3.30)	$ (0.45)	$ 0.30	$ (2.79)
Earnings (loss) per common share – assuming dilution:							
Income (loss) before extraordinary item	**$ 3.01**	$ 0.16	$ (9.83)	$ (3.30)	$ (0.45)	$ 0.38	$ (2.69)
Extraordinary item	**—**	—	(0.14)	—	—	(0.10)	(0.10)
Net income (loss)	**$ 3.01**	$ 0.16	$ (9.97)	$ (3.30)	$ (0.45)	$ 0.28	$ (2.79)
Other financial data:							
Operating cash flow	**$ 304,934**	$ 137,884	$ 115,200	$ 226,639	$ 141,248	$ 77,325	$ 162,716
Balance sheet data (at end of period):							
Total assets	**$ 1,440,426**	$ 850,533	$ 812,615	$ 952,784	$ 952,784	$ 860,597	$ 949,068
Long-term debt, net of current maturities	**944,845**	964,097	919,076	508,992	508,992	220,149	508,950
Stockholders' equity (deficit)	**313,232**	(217,544)	(248,568)	280,206	280,206	484,062	286,889
Property Data *($ in thousands)*							
Oil reserves (mbbls)	**25,565***	24,795	22,593	18,226	18,226	**	17,373
Gas reserves (mmcf)	**1,502,940***	1,056,826	955,791	339,118	339,118	**	298,766
Reserves in equivalent thousand barrels	**276,055***	200,933	181,891	74,746	74,746	**	67,167
Reserves in equivalent million cubic feet	**1,656,328***	1,205,595	1,091,348	448,474	448,474	**	403,004
Future net revenues discounted at 10%	**$ 7,312,531***	$ 1,089,496	$ 660,991	$ 466,509	$ 466,509	**	$ 437,386
Future net revenues undiscounted	**$13,315,779***	$ 1,891,175	$ 1,208,641	$ 715,098	$ 715,098	**	$ 611,954
Oil price used in reserve report ($ per bbl)	**26.42***	24.72	10.48	17.62	17.62	**	18.38
Gas prices used in reserve report ($ per mcf)	**10.13***	2.25	1.68	2.29	2.29	**	2.12
Oil production (mbbls)	**3,068**	4,147	5,976	3,511	1,857	1,116	2,770
Gas production (mmcf)	**115,771**	108,610	94,421	59,236	27,326	30,095	62,005
Production in equivalent thousand barrels	**22,363**	22,249	21,713	13,384	6,411	6,132	13,104
Production in equivalent million cubic feet	**134,179**	133,492	130,277	80,302	38,468	36,791	78,625
Average oil sale price ($ per bbl)	**26.39**	16.01	12.70	19.39	18.59	21.88	20.93
Average gas sale price ($ per mcf)	**3.36**	1.97	1.92	2.20	2.24	2.18	2.18
Average gas equivalent sale price ($ per mcfe)	**3.50**	2.10	1.97	2.47	2.49	2.45	2.45

Includes Chesapeake and Gothic Energy Corporation on a combined basis at December 31, 2000. Chesapeake acquired Gothic on January 16, 2001.

*** An independent appraisal of our oil and gas reserves was not performed as of December 31, 1996, because our fiscal year-end at that time was June 30.*

Letter to Shareholders

Dear Shareholders:

Last year was a momentous one for our company in many respects. First and foremost, we generated remarkable financial results – net income of $456 million, operating cash flow of $305 million and a $725 million increase in common equity. In addition, including our recently completed Gothic Energy acquisition, Chesapeake's proved reserves increased 37% to a record level of 1.7 trillion cubic feet of natural gas equivalent, a 436% reserve replacement rate.

Second, our performance in the stock market was among the country's finest – the 8th best performer on the NYSE, up 326% for the year. Since reaching a low of $0.75 in early 1999, Chesapeake's stock price has increased over 1,500%, one of the strongest performances among all publicly traded companies during the past two years.

Third, we have successfully established Chesapeake as one of the top five pure plays in the U.S. natural gas exploration and production business. As we continue to grow our assets and improve our balance sheet, we believe Chesapeake's shareholders will enjoy another exceptional year in 2001.

Our Thoughts on the Natural Gas Business:

Strategy Shift

Chesapeake's strategic shift toward natural gas as our fuel of choice in late 1997 did not occur by accident. To recall the context for this decision, we had just reported an expensive $350 million failure in our efforts to extend Chesapeake's highly successful Deep Giddings Austin Chalk Trend from Texas into Louisiana, where we had hoped to find as much as $5-10 billion of oil and natural gas. Realizing that we

Natural Adva

needed to adjust our business model to accept the limitations of slower future growth while lowering our risk profile, we embarked on the most ambitious corporate makeover the industry has seen during the past 10 years.

The fundamental goal in our transition was simple: we decided to acquire as many natural gas reserves as we could afford, ultimately acquiring 750 billion cubic feet of natural gas equivalent (bcfe) for $750 million in six months. Although our acquisition pricing was considered aggressive at the time, in retrospect our purchases have proved to be great bargains.

Why Natural Gas vs. Oil?

Heavily influenced by our own experiences on the front lines searching for large new reserves of natural gas, we believed it would be almost impossible for our industry to meaningfully increase the supply of natural gas in the years ahead. We also recognized that a growing economy, stricter environmental regulations and the coming onslaught of gas-fired electrical generation would serve as catalysts for strong natural gas demand growth and, almost certainly, higher natural gas prices.

In addition, we significantly lowered our risk profile by focusing Chesapeake's search for natural gas reserves in our own backyard of the Mid-Continent region (Oklahoma, the Texas Panhandle, and SW Kansas) and by growing through a balanced development program of both drilling and acquisitions.

The Downturn of '98

By mid-1998 we believed our strategic transformation was complete and would provide a strong base for the company to return to industry prominence. Unfortunately, we were a bit early. External factors such as the Asian financial crisis, three of the warmest winters of the 20th century and an oil production miscalculation by OPEC caused oil and natural gas prices to fall to 30-year inflation-adjusted lows by early 1999.

It was a time when the "experts" were all in agreement: oil and natural gas prices would remain low indefinitely, E&P companies were fundamentally flawed businesses (we spent too much, didn't find enough, were too small to matter, were too "old economy", etc), and worst of all – E&P management teams were alleged to have consistently destroyed value over the previous 15 years.

Unlike some of our peers who elected to sell assets (or their companies) at the bottom of this cycle, we were confident that Chesapeake's strategic repositioning had been well-executed and that a cyclical upturn in oil and natural gas prices was inevitable. The rest, as they say, is history. In early 1999 investors could have acquired all of Chesapeake's common stock as the equivalent of a five-year call option on over a trillion cubic feet of natural gas for less than $100 million. Today, the present value of our reserves is over $3.2 billion.

California and the U.S. Energy Crunch

We believe this review of where we've been is not just important for your understanding of why Chesapeake's strategy is working, but it's also critical to understanding almost everything about the energy business today. California's electricity and natural gas shortages, high oil prices worldwide, high natural gas prices, potential electricity shortages this summer in NYC and in the Midwest, and finally, a possible replay of this in 2002 - all of these problems have their roots in the low energy prices and energy policy complacency of the past 15 years.

In a nutshell, when a country embarks on a binge of energy consumption (electricity usage is up 43% since 1985) and fails to invest enough in its energy supply and delivery infrastructures along the way, something has to give. That something is always price.

It's the Producers and their Shareholders' Turn Now

As it turns out, we and other E&P management teams have not done such a poor job of creating value during the past 15 years. It's simply that the value we created through the expensive, risky and time-consuming search for new supplies of energy was transferred to American consumers rather than to our industry's shareholders as a result of excess supplies of oil, natural gas and electricity. The net result of this extended period of low energy prices was a 15-year boom in U.S. and worldwide growth from 1985-2000 (obviously accelerated by enormous technological advancements) that gradually eliminated the excess supply of electricity, natural gas and oil.

As we have all learned over the years, what goes around comes around and the imbalance is now in favor of energy producers. Today, we are in an environment where enormous value is being created by Chesapeake and our industry. This time, however, that value is being retained by our shareholders. Persistently high energy prices and huge value creation in the energy industry will be a fact of American life for at least the next five years.

High Energy Prices Will Be With Us for a While

Most Americans do not understand the time and money needed to make the required energy investments that can increase supply enough to lower energy prices. Simply stated, it has taken us 15 years to get into the current energy crunch and it's going to take a while to get out. This will require massive amounts of capital from investors – capital that in the past 15 years has generally been invested in everything that consumes energy and will now need to be invested in everything that produces and transports energy. Affecting such a change in investing preferences won't be easy, but we believe the market will force it to happen through the twin realizations that higher energy prices are with us for a while and that energy producers' stock prices don't reflect the intrinsic value of the assets they own.

In addition, for the energy industry to generate greater supplies, more attention will have to be paid to the cost-benefit relationship of environmental regulations. For years, our country's policies of favoring a pristine environment while demanding cheap energy have been on a collision course. A more rational approach is required. We believe that both environmentalists and policymakers will have to realize that natural gas is the only fuel that can quickly deliver much needed new supplies of energy in an environmentally friendly manner.

Natural gas has numerous natural advantages over coal, oil and renewables and we believe that it can continue to trade at a BTU premium to competing fuels. By extension, we believe that over time natural gas producers' stock prices will also be valued at much higher multiples in the market. As this summer rolls on and higher electricity and natural gas prices spread from California throughout the interconnected western U.S. and on to the Midwest and East Coast, we believe investors will increasingly appreciate how well Chesapeake is prepared for this opportunity and is positioned to profit from these trends.

Chesapeake's Primary Objective and Business Strategy

Chesapeake's primary objective is simple: we desire to be the most profitable producer of natural gas in the U.S. on a per-unit-of-production basis in order to generate the industry's highest returns to shareholders. Of the more than 200 publicly traded producers listed on U.S. stock exchanges, Chesapeake is already among the 10 most profitable by this important measure. As we continue to grow our asset base and further improve our capital structure, we will continue advancing toward our goal of being the best in the industry at exploring for, developing, acquiring and producing onshore natural gas.

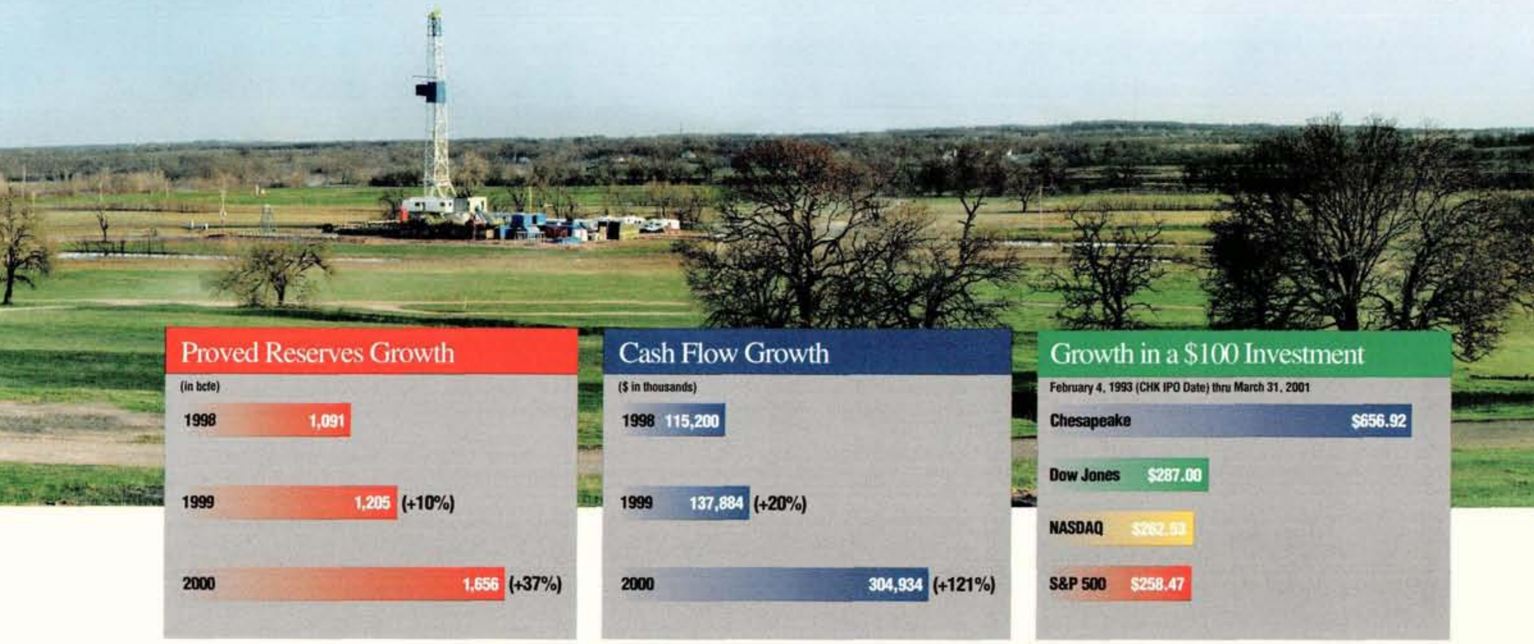
Chesapeake's strategy for achieving its goal is also straightforward: using our extensive geological and operational expertise created through having drilled or acquired over 6,700 wells during the past 12 years, our company will continue to conduct one of the most technologically sophisticated searches for onshore natural gas in the U.S. In addition, we will continue to increase our two million acre leasehold inventory, which contains more than 1,500 additional drilling opportunities. It is the backbone of our ability to create future shareholder value. Furthermore, we will continue to aggressively and economically consolidate smaller asset packages in each of our four major core operating areas, with particular emphasis on the key Mid-Continent area. The combination of these efforts should enable us to achieve Chesapeake's goal of generating industry-leading returns.

Chesapeake's Newest Exploration Project – The Georgetown in Deep Giddings

During the past three years, Chesapeake has transformed itself from a high-risk, exploration oriented operator in fractured carbonate formations into a low-risk driller and acquirer of Mid-Continent natural gas reserves. However, just because we have focused on lowering our risk profile, it would be a mistake to assume we no longer have an inventory of exciting drilling projects with the opportunity for significant production growth. In fact, Chesapeake is one of the top 10 drillers in the U.S. and has a number of high-potential drilling projects in both the Anadarko and Arkoma Basins of Oklahoma. Typically drilled to below 15,000', these deep projects in Oklahoma have the potential to find more than 10 bcfe per well.

Chesapeake's project area that is today generating more industry attention than any other is the Georgetown play in the Deep Giddings Field in Texas. Many of you may recall that the springboard for Chesapeake's phenomenal returns to shareholders during 1994-96 (when Chesapeake increased in value by 90-fold and was the best

Natural Gas



performing stock in America during that three-year period) was the company's extraordinary drilling success in its Navasota River and Independence project areas. Located in Brazos, Grimes and Washington Counties, Texas, Chesapeake's Deep Giddings wells developed over 600 bcfe of proved reserves, an amount that at today's prices would create over $3 billion in value.

Virtually all of this gas was produced from the Austin Chalk, the uppermost of a series of four deep fractured carbonate reservoirs. The other three, the Georgetown, Edwards, and Glen Rose, were largely ignored as potential drilling targets because of the enormous productivity of the Austin Chalk. As production from the company's Chalk wells began to deplete, Chesapeake's geoscientists initiated a project to test the exciting potential of these deeper zones.

The company's first two deeper wells have demonstrated the tremendous potential of at least one of the deeper zones, the Georgetown. Both of these wells generated sufficient revenues in just their first 30 days of production to completely pay for their drilling costs. Although they have only been producing on average for less than four months, the wells have generated 5.1 bcfe of production and total revenues of $30 million compared to total costs of $7 million. These are ideal wells to be drilling in today's natural gas price environment.

While the company does not expect all of its Georgetown wells to be of this same quality, we believe the combination of our 100,000 leasehold acres in the Deep Giddings area and today's $5+ natural gas prices mandate an acceleration of our Georgetown drilling. As of this date, Chesapeake has decided to increase its Deep Giddings commitment from one to 4-5 rigs to broadly test our prospective Georgetown acreage. Based on initial results and our expertise in drilling deep horizontal wells, we are optimistic that the Georgetown, and possibly the other two deeper zones in Giddings, have the potential to make a significant contribution to the company's production and reserves in 2001 and beyond.

Looking Ahead

As we look ahead to what should be a terrific environment for Chesapeake and our shareholders, we believe it's worth repeating our conclusion from last year's letter to you: "As this decade unfolds, we believe investors will increasingly envision this 21st century as the age of natural gas. Just as great wealth was created during the 20th century in the age of oil and in the 19th century as the age of coal, we believe investors will greatly profit from embracing the tremendous potential of the natural gas industry." A year later, we still feel the same way and believe many more investors share our view.

The year 2000 was a pivotal and rewarding year for our company. In just 12 years, Chesapeake has progressed from a $50,000 start up to one of the largest and most profitable natural gas producers in the industry. And in just the eight years since our IPO, $100 invested in Chesapeake would today have grown to $657, compared to $287 if invested in the DJIA, $263 in the NASDAQ and $258 in the S&P 500. Although we are proud of Chesapeake's past track record of value creation, we believe the years ahead can be even more rewarding.

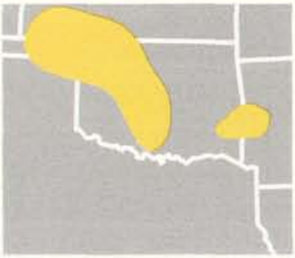
Best regards,

Aubrey K. McClendon

Tom L. Ward

April 12, 2001

Primary Operating Areas

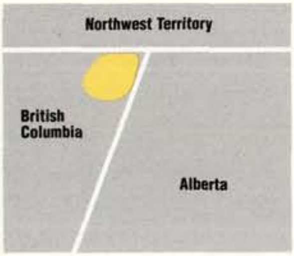


Mid-Continent

Chesapeake's Mid-Continent proved reserves of 967 bcfe represented 71% of our total proved reserves as of December 31, 2000, and this area produced 78.3 bcfe, or 58% of our 2000 production. During 2000, we invested approximately $109.1 million to drill 311 (149.8 net) wells in the Mid-Continent. We anticipate spending approximately 60% to 70% of our total budget for exploration and development activities in the Mid-Continent region during 2001. We anticipate the Mid-Continent will contribute approximately 116 bcfe of production during 2001, or 65% of expected total production.

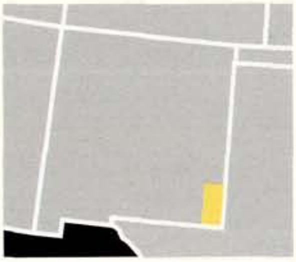
Gulf Coast

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 158 bcfe, or 12% of our total proved reserves as of December 31, 2000. During 2000, the Gulf Coast assets produced 35.2 bcfe, or 26% of our total production. During 2000, we invested approximately $21.5 million to drill 12 (6.4 net) wells in the Gulf Coast. In 2001, we anticipate the Gulf Coast will contribute approximately 38 bcfe of production, or 21% of expected total production. We anticipate spending approximately 15% to 20% of our total budget for exploration and development activities in the Gulf Coast region during 2001.



Helmet

Chesapeake's Canadian proved reserves of 159 bcfe represented 12% of our total proved reserves at December 31, 2000. During 2000, production from Canada was 12.1 bcfe, or 9% of our total production. During 2000, we invested approximately $13.6 million to drill 14 (6.9 net) wells, install various pipelines and compressors and to perform capital workovers in Canada. We anticipate spending approximately 9% of our total budget for exploration and development activities in Canada during 2001 and expect production of 15 bcfe in Canada, or 8% of our estimated total production for 2001.



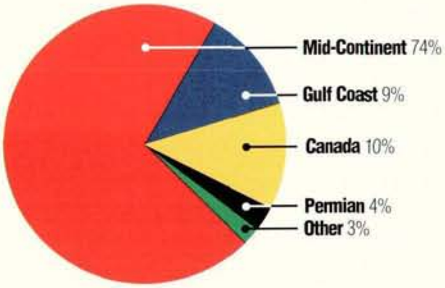
Permian Basin

Chesapeake's Permian Basin proved reserves, consisting primarily of the Lovington area in New Mexico, represented 21 bcfe, or 2% of our total proved reserves as of December 31, 2000. During 2000, the Permian assets produced 6.2 bcfe, or 5% of our total production. We anticipate the Permian Basin will contribute approximately 5 bcfe of production during 2001, or 3% of expected total production. During 2000, we invested approximately $13.6 million to drill 13 (8.8 net) wells in the Permian Basin. For 2001, we anticipate spending approximately 3% to 4% of our total budget for exploration and development activities in the Permian Basin.

Other Operating Area

In addition to the primary operating areas described above, which consist primarily of natural gas properties, Chesapeake maintains operations in the Williston Basin of North Dakota, Montana, and Saskatchewan, Canada which are focused on developing oil properties. In 2000, these areas contributed 2.4 bcfe, or 2% of our total production. In 2001, production levels should increase to approximately 4 bcfe as a result of allocating approximately 2% of our total budget for exploration and development activities in these areas.

Proved Reserves by Area (mmcfe)



Directors and Officers

Directors

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

Tom L. Ward
President and Chief
Operating Officer
Oklahoma City, Oklahoma

E. F. Heizer, Jr.
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Officers

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Chief Executive Officer

Tom L. Ward
President and Chief
Operating Officer

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Executive Vice President and
Chief Financial Officer

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Chief Accounting Officer

James C. Johnson
President – Chesapeake Energy
Marketing, Inc.

Stephen W. Miller
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Drilling

The Chesapeake 2001 Team

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Stephen Adams
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Bill Albert
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Richey Albright
Sam Allen
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Karla Allford
Eduardo Alvarez-Salazar
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Mark Anderson
Colley Andrews
Judy Arias
Paula Asher
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Terry Ashton
Shellie Ashworth
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Debbie Brummett
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Martha Burger
Karl Burkard
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Shelli Butler
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Marty Byrd
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Ted Campbell
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Ilan Cathey
Tasha Chamberlain
Melissa Chambers
Bill Chatham
Courtney Cherry
Sherri Childers
Mike Childress
Sherry Childress-Walton
Rachel Clapp
Ivajean Clark
David Cochran
Steve Cody
Jennifer Cole
Michael Coles
Gary Collings
Brenda Condit
Kristine Conway
Walter Cook
Dale Cook, Jr.
Juanita Cooper
Jennifer Copeland
Kendra Copeland
Randy Cornelsen
Jim Corsoro
Frank Coshow
Larry Coshow
Bob Costello
Joe Cox
Tim Crain
Carrie Crawford
David Craycraft
Terie Crookshank
Michelle Cullen
Audra Cumings
Debbie Curtis
Keith Curtis, Jr.
Ken Davidson
Kristi Davis
Cheryl Davis
Ted Davis
Jason Davis
Tammy Day
Mark Deal
Kevin Decker
George Denny
Tim Denny
Dave Desalvo
Alton Dickey
Steve Dixon
Bruce Dixon
Gary Doak
Kim Doty
Dory Douglas
Mac Drake
Greg Drwenski
Mandy Duane
Gary Dunlap
Don Dunn
Jeremy Durkee
Jason Dye
Jeff Eager
Laurie Eck
Mark Edge
Gary Egger
Steve Emick
Brent Engles
Kyle Essmiller
Dan Estes
Mark Evans
Jan Fair
Scot Fankhouser
Jenny Ferguson
Tammy Fields
Gary Finn
Kristin Fitzgerald
Gregg Flaming
Charles Floyd
Pam Ford
Barbara Frailey
Joy Franklin
Sherry Freeman
Dennis Frick
Crystal Fuchs
Jeanie Fuller
Linda Gardner
Terry Garrison
Dan Garvey
Randy Gasaway
Steve Gaskins
Jeff Geis
Stacy Gilbert
Rob Gilkes
Kim Ginter
Charlene Glover
Randy Goben
Ron Goff
Jim Gomez
Robin Gonzalez
Traci Gonzales
Pat Goode
Erin Goodin
Gena Goodwin
Marty Gore
Tony Gore
Jimmy Gowens
Ranae Green
Tana Griggs
Jennifer Grigsby
Melissa Gruenewald
Brian Guire
Shane Hamilton
Cheryl Hamilton
Kelsey Hammit
Tresa Hammond
Jean Hammond
Cliff Hanoch
Jeff Harris
Gayle Harris
Mary Hartman
Caleb Hause, Jr.
Jimmy Hayes
Candace Haynes
Mike Hazlip
Duane Heckelsberg
Tracie Hefferan
Robert Hefner IV
Terri Helton
Heidi Henry
David Higgins
Twila Hines
Dana Hodgin
Carol Holden
Henry Hood
Marilyn Hooser
Kenny Hopkins
Michael Horn
Jennifer Hornsby
Yamei Hou
Ronnie Howell
Cindy Hubbard
Rick Hughes
Eric Hughes
Ted Hulett
Debbie Hulett
Brian Imes
Charles Imes
Julie Ingram
Christina Ivy
Jeremiah Jackson
Lorrie Jacobs
Douglas Jacobson
Jennifer Jacques
Eugene James
Melissa Jarvis
Justin Johnson
Doug Johnson
Jim Johnson
Mike Johnson
Mike Johnston
Marvin Jones
Rob Jones
Cynthia Jones
David Jones
Katy Jump
Susan Keller
Jim Kelley
Tammy Kelln
Taylor Kemp
James Kenneda
Phyllis Kimray
Steve King
Terry Kite
Darvin Knapp
Greg Knight
Ted Krigbaum
Wes Kruckenberg
Jim Kuhlman
Sandi Lagaly
Mike Lancaster
Steve Lane
Gwen Lang
Jesse Langford, Jr.
Barry Langham
Juanita Laplante
Kim Laughlin
Cindy Leblanc
Mike Lebsack
Dan LeDonne
Chris Lee
Randy Lee
Don Lee
Kim Legg
Steven Lepretre
Mark Lester
Fred Lewis
Darwin Lindenmuth
Melanie Lingafelter
Debbie Lloyd
Lynn Looper
Kinney Louthan
Kimberly Louthan
Janet Lowrey
Mike Ludlow
Sarah Lumen
Larry Lunardi
Craig Madsen
Troy Mahan
Felipe Maldonado
John Marks
John Marshall
Robyn Martin
Laura Martini
Kim Massey
Sandy Mathis
Allen May
J. May, Jr.
Andrea McCall
Sam McCaskill
Aubrey McClendon
Joe McClendon
Cindy McClintock
Carrol McCoy
Collin McElrath
Kevin McElyea
Dennis McGee
Greg McMahan
Janelle McNeely
Sondra McNeiland
Marti Meek
Dea Mengers
Don Messerly
Alan Miller
Mike Miller
Steve Miller
Drew Miller
William Miller
Carey Milligan
David Mobley
Georgia Moller
Linda Mollman
Heather Moody
Debby Morgan
Tommy Morphew
Nathan Morrison
James Morton
Pat Murano
Eric Murray
Leland Murray
David Murray
Liz Muskrat
Wes Myers
Tara Nash
Steve Nath
Bob Neely
Bud Neff, Jr.
Melinda Neher
Lee Nelson
John Nelson II
Jay Newton
Tim Newville
Tammy Nguyen
Kathy Nowlin
Gerda Oliver
Brad O'Quin
Mecca Osban
Lisa Owens
Don Pannell
Michael Park
Dawn Parker
Sharon Patterson
Mandy Pena
Linda Peterburs
Barbi Phelps
Dianne Pickard
Randy Pierce
Pat Pope
Rob Pope
Erick Porter
Fred Portillo
Bobby Portillo
Angela Ports
Robert Potts
Buddy Powell, Jr.
Tom Price, Jr.
Tom Putz
John Qualls
Kimberly Queen
Glenda Ratcliffe
LaCosta Rawls
Lori Ray
Lynn Regouby
Aaron Reyna
Debby Richardson
Nancy Richardson
Carole Robinson
Matt Rockers
Les Rodman
Pat Rolla
Larry Ross
Michelle Rother
Annie Rother
David Roule
Ray Roush
Marc Rowland
Don Rozzell
Kelly Ruminer
Danny Rutledge
Bryan Sagebiel
Rose Sales
Elizabeth Salyer
Mike Sawatzky
Tony Say
Wendy Schaub
Hank Scheel
Maria Scherff
Patti Schlegel
Charles Scholz
Kurt Schrantz
Delores Schreiber
Jolene Schur
Melody Scoll
Dan Scott
Ricky Scruggs
Brent Scruggs
Cheryl Self
Larry Settle
Vanessa Shantz
Tom Sharp
Stephanie Shedden
Larry Shipley
Vance Shires
Mike Shklar
Arlene Shuman
Carolyn Simmons
Kristin Sipe
Stuart Skelton
Chris Skidmore
Greg Small
Vivian Smith
Sylvia Smith
Charlie Smith
David Smith
Sandra Smith
Wilma Smith
April Smith
Bill Snyder
Jimmy Snyder
Chris Sorrells
George Soto
Antonio Soto
Chantelle Sousa
Dan Sparks
Catherine Stairs
Jeff Stanford
Krysta Starkey
Linda Steen
William Stillwell
Stan Stinnett
Michael Stow
Brenda Stremble
John Striplin
Jerry Sublette
Brandy Sullens
Randy Summers
Stacy Swigart
Alison Tabares
Iris Tadlock
Tim Taylor
Alan Tayrien
Becky Thomas
Jenny Thompson
Trish Thompson
Rachel Thompson
Lynda Townsend
John Tracy
Connie Turner
Ken Turner
Larry Turner, Jr.
Courtney Tyson
Rob Underwood, Jr.
Frank Unsicker
Tonya Vallerand
Jennifer VanMeir
Shelby VanWinkle
Joe Vaughan
Peggy Vosika
Dung Vu
Kay Vuong
Bill Wagner
Paul Waits
Allan Waldroup
Ronnie Walker
Rusty Walker
Ronnie Ward
Tom Ward
Julie Washam
Patsy Watters
Clarence Watts
Nick Wavers
Brian Weaver
Melanie Weaver
Janet Weeks
Greg Weinschenk
Lu Ann Wernli
Mandy Whipple
Dennis Whipple
Shelly White
Scott White
Craig White
Paige Whitehead
Bob Whitman
Mary Whitson
David Whitten
Sam Wilder
Ken Will
Jeff Williams
Connie Williams
Brent Williams
Cindi Williams
Dori Williams
Curtis Williford
Tina Willingham
Durell Willoughby
Dawn Wilson
Randall Wilson
Ginni Winchester
Brian Winter
Marvin Winter
Lon Winton
Dave Wittman
Bob Woodside
Jimmy Wright
Nancy Wyskup
Tobin Yocham
Jeri York
Terri Young
Alan Zeller
Gerald Zgabay

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

FORM 10-K/A
Amendment No. 1

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

For the Fiscal Year Ended December 31, 2000

[ ] 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
9.625% Senior Notes due 2005	New York Stock Exchange
9.125% Senior Notes due 2006	New York Stock Exchange
8.5% Senior Notes due 2012	New York Stock Exchange
7% Cumulative Convertible Preferred Stock, par value $.01	New York Stock Exchange

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES [X] NO [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

The aggregate market value of Common Stock held by non-affiliates on March 23, 2001 was $1,191,694,668. At such date, there were 158,023,477 shares of Common Stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2001 annual meeting of shareholders are incorporated by reference in Part III

PART I

ITEM 1. *Business*

General

We are among 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. Chesapeake maintains a website at *www.chkenergy.com.* Information contained on our website is not part of this report.

At the end of 2000, we owned interests in approximately 6,000 producing oil and gas wells. Our primary operating area is the Mid-Continent region of the United States, which includes Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle. Other core operating areas include: the Deep Giddings field in Texas, which includes the Austin Chalk and Georgetown formations; the Helmet area of northeastern British Columbia; and the Permian Basin region of southeastern New Mexico. The following table highlights our growth since 1995:

	Years Ended December 31,						Five-Year Average Annual Growth Rate
	1995	1996	1997	1998	1999	2000	
Production (mmcfe)	47,429	69,867	80,302	130,277	133,492	134,179	26%
Proved reserves (mmcfe)	457,851	494,000	448,474	1,091,348	1,205,595	1,656,328(a)	38%
EBITDA ($ in 000's)	$ 73,600	$144,340	$ 256,421	$ 183,449	$ 218,936	$ 391,190	49%
Operating cash flow ($ in 000's)	$ 63,366	$130,989	$ 226,639	$ 115,200	$ 137,884	$ 304,934	54%
Net income (loss) ($ in 000's)	$ 14,451	$ 39,902	$(233,429)	$ (933,854)	$ 33,266	$ 455,570	191%

(a) These reserves reflect Chesapeake and Gothic on a combined basis at December 31, 2000.

Business Strategy

From inception in 1989, our business strategy has been to aggressively build and develop one of the largest onshore natural gas resource bases in the United States. We are executing our strategy by:

- continuing to grow through the drillbit by conducting what we believe is currently one of the five most active drilling programs in the United States. We currently have 24 rigs drilling on Chesapeake-operated prospects and we are participating in 27 wells being drilled by others;
- continuing to make small acquisitions of strategically located natural gas properties that provide high quality production and significant drilling opportunities. In 2000, we acquired approximately $75 million of such producing properties in 97 separate transactions. Each of these acquisitions either increased our working interest in existing wells or added additional drilling locations in our core areas. In 2001, we have budgeted $140 million for similar acquisitions. In our experience, smaller acquisitions generally provide better economics than larger corporate or property acquisitions;
- funding our $450 million 2001 capital expenditure plan with operating cash flow and reducing our debt with our projected excess cash flow; and
- maintaining a low operating cost structure so that we can deliver attractive financial returns from our assets in all phases of the commodity price cycle.

Based on our view that natural gas has become the fuel of choice to meet growing power demand and increasing environmental concerns, we believe our strategy should provide substantial growth opportunities in the years ahead.

Company Strengths

We believe our past performance and future growth potential are primarily attributable to five characteristics that distinguish us from other independent oil and natural gas producers:

High-Quality Asset Base. Our properties are characterized by long-lived reserves, established production profiles and an emphasis on natural gas. Based upon 2000 production and our year-end reserves, our proved reserves-to-production ratio, or reserve life, is more than ten years. In each of our four core 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 concentrating our acquisition and drilling efforts in our four core operating areas, with particular emphasis on the Mid-Continent region where approximately 74% of our proved reserves, including Gothic's reserves, are located.

Low-Cost Producer. Our high-quality asset base has enabled us to achieve a low operating cost structure. During 2000, our cash operating costs per unit of production, which consist of general and administrative expenses and production expenses and taxes, were $0.66 per mcfe. We believe this is one of the lowest operating cost structures among publicly traded independent oil and natural gas producers. We operate approximately 71% of our proved reserves, including Gothic's reserves, providing a high degree of operating flexibility and cost control.

Successful Acquisition Program. Our acquisition program is focused primarily in the Mid-Continent region. This region 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, we have successfully completed $1.2 billion in acquisitions at an average cost of $0.98 per mcfe. We believe we are well positioned to continue this consolidation as a result of our large existing asset base, our corporate presence in Oklahoma City and our knowledge and expertise in the Mid-Continent.

Large Inventory of Drilling Projects. During the past 12 years, we believe we have been one of the ten most active drillers in the United States, especially of deep vertical and horizontal wells in challenging reservoir conditions. As a result of our land acquisition strategy, we have developed an onshore leasehold position of approximately 2.5 million net acres. 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.

Entrepreneurial Management. Our management team formed Chesapeake in 1989 with an initial capitalization of $50,000. Through the following years, our management team has guided the 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 with an enterprise value at March 15, 2001 of $2.7 billion. In addition, through its ownership of approximately 23 million shares of our common stock, our management has a strong interest in increasing shareholder value.

2000 Highlights

Chesapeake's operating results for the year ended December 31, 2000 established several records for our company:

- net income of $456 million (including a $265 million reversal of a tax valuation allowance), compared to net income of $33 million in 1999,
- operating cash flow of $305 million, compared to operating cash flow of $138 million in 1999,
- production of 134 bcfe, of which 86% was natural gas, and
- proved oil and gas reserves of 1,656 bcfe pro forma for the Gothic acquisition, an increase of 37% from the year ended December 31, 1999.

During 2000, we also replaced 585 bcfe of proved reserves at a replacement cost of $1.07 per mcfe, pro forma for the Gothic acquisition.

Gothic Acquisition

On January 16, 2001, we completed the acquisition of Gothic with the issuance of four million of our common shares to Gothic shareholders. Prior to the completion of the acquisition, we purchased substantially all of Gothic's 14.125% senior secured discount notes and $32 million of Gothic Production's 11.125% senior secured notes for total consideration of $116 million in cash and our common stock. At the time of the acquisition, Gothic Production had $235 million of 11.125% senior secured notes due in 2005, including the $32 million of notes we purchased prior to closing.

As of December 31, 2000, Gothic had proved reserves of 291 bcf of natural gas and 1.8 mmbbls of oil (a total of 302 bcfe) with a pre-tax present value (calculated as described in the glossary using weighted average gas and oil prices of $10.19 per mcf and $26.54 per barrel) of approximately $1.3 billion. These reserves, of which 85% were classified as proved developed, had an estimated average reserve life of approximately 11 years, and 96% of these reserves were natural gas. Gothic's natural gas reserves and acreage, most of which were acquired from Amoco Production Company, are principally located in the Anadarko and Arkoma basins of the Mid-Continent, have low operating costs per mcfe and are an excellent fit with our existing reserve base.

At December 31, 2000, Gothic held an interest in approximately 480,000 (229,000 net) acres and had an interest in 903 (481 net) producing wells. For the year ended December 31, 2000, Gothic had revenues of $86 million, EBITDA of $68 million, operating cash flow of $29 million and net income of $6 million. Gothic's consolidated financial statements and the pro forma combined financial statements are included in Item 8 — Financial Statements and Supplementary Data.

Improving Our Capitalization

We made significant progress in improving our balance sheet during 2000, increasing common shareholders' equity by over $725 million in a combination of preferred stock exchanges, equity issuances and earnings. Total debt obligations and preferred stock outstanding were $1.2 billion, or $0.99 per mcfe of proved reserves, at the beginning of 2000. These fixed obligations were reduced to $976 million, or $0.72 per mcfe of proved reserves, by the end of 2000.

We have called for redemption on May 1, 2001 all the outstanding 624,037 shares of our 7% cumulative convertible preferred stock, which are convertible into common stock at a conversion price of $6.95 per share. Other than the redemption premium, which will be paid in cash, we intend to use our common stock to redeem any shares of the outstanding preferred stock that are not converted into common stock prior to the redemption date.

On March 29, 2001, we announced a proposed private offering to sell $800 million of senior notes due 2011 in order to lower the interest rate and extend the maturity of approximately 74% of our senior notes. If the offering is successfully completed, the proceeds from the proposed offering, together with available cash and bank borrowings, would be used to redeem Chesapeake's existing $120 million principal amount of 9.125% senior notes due 2006, $500 million principal amount of 9.625% senior notes due 2005 and $202.5 million principal amount of 11.125% senior secured notes due 2005 of Gothic Production Corporation, a Chesapeake subsidiary. Redemption of these notes will include payment of aggregate make-whole and redemption premiums estimated at approximately $74 million. The notes to be offered by Chesapeake would not be initially registered under the Securities Act of 1933, as amended, and will not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

2001 Outlook

At the present time, we believe the outlook for Chesapeake is favorable because of our large base of high quality natural gas properties, our geological and operational expertise and very strong natural gas and oil prices. Our goals and the strategy to obtain those goals remain unchanged for 2001:

- replace production by more than 200% at a low reserve replacement cost,
- execute a capital expenditure plan balanced between drilling and acquisitions, funded with operating cash flow,
- maintain a superior operating cost structure,
- utilize excess cash flow above budgeted expenditures to reduce debt both relatively and absolutely, and
- deliver attractive financial returns from our assets in all phases of our energy cycle.

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,					
	1998		1999		2000	
	Gross	Net	Gross	Net	Gross	Net
United States						
Development:						
Productive	158	93.9	167	93.3	291	142.7
Non-productive	9	4.7	17	10.6	12	5.3
Total	167	98.6	184	103.9	303	148.0
Exploratory:						
Productive	46	23.4	9	3.7	32	17.0
Non-productive	9	6.8	6	4.6	11	5.4
Total	55	30.2	15	8.3	43	22.4
Canada						
Development:						
Productive	11	3.6	11	7.3	12	6.1
Non-productive	1	0.4	1	0.2	2	.8
Total	12	4.0	12	7.5	14	6.9
Exploratory:						
Productive	1	0.3	—	—	—	—
Non-productive	7	2.1	—	—	—	—
Total	8	2.4	—	—	—	—

At December 31, 2000, we had 46 (22.2 net) wells in process.

Well Data

At December 31, 2000, we had interests in approximately 6,000 (2,675 net) producing wells, of which 270 (125 net) were classified as primarily oil producing wells and 5,730 (2,550 net) were classified as primarily gas producing wells. Chesapeake operates approximately 4,000 of the total 6,000 producing wells.

Including Gothic's wells as of December 31, 2000, our producing well count increases to approximately 6,700 (3,200 net) wells, of which Chesapeake operates 4,300.

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,								
	1998			1999			2000		
	U.S.	Canada	Combined	U.S.	Canada	Combined	U.S.	Canada	Combined
Net Production:									
Oil (mbbl)	5,975	1	5,976	4,147	—	4,147	3,068	—	3,068
Gas (mmcf)	86,681	7,740	94,421	96,873	11,737	108,610	103,694	12,077	115,771
Gas equivalent (mmcfe)	122,531	7,746	130,277	121,755	11,737	133,492	122,102	12,077	134,179
Oil and Gas Sales ($ in thousands):									
Oil	$ 75,867	$ 10	$ 75,877	$ 66,413	$ —	$ 66,413	$ 80,953	$ —	$ 80,953
Gas	173,042	7,968	181,010	200,055	13,977	214,032	355,391	33,826	389,217
Total oil and gas sales	$248,909	$7,978	$256,887	$266,468	$13,977	$280,445	$436,344	$33,826	$470,170
Average Sales Price:									
Oil ($ per bbl)	$ 12.70	$10.00	$ 12.70	$ 16.01	$ —	$ 16.01	$ 26.39	$ —	$ 26.39
Gas ($ per mcf)	$ 2.00	$ 1.03	$ 1.92	$ 2.07	$ 1.19	$ 1.97	$ 3.43	$ 2.80	$ 3.36
Gas equivalent ($ per mcfe)	$ 2.03	$ 1.03	$ 1.97	$ 2.19	$ 1.19	$ 2.10	$ 3.57	$ 2.80	$ 3.50
Expenses ($ per mcfe):									
Production expenses	$ 0.40	$ 0.24	$ 0.39	$ 0.36	$ 0.18	$ 0.35	$ 0.38	$ 0.32	$ 0.37
Production taxes	$ 0.07	$ —	$ 0.06	$ 0.11	$ —	$ 0.10	$ 0.20	$ —	$ 0.19
General and administrative	$ 0.16	$ 0.06	$ 0.15	$ 0.10	$ 0.08	$ 0.10	$ 0.09	$ 0.17	$ 0.10
Depreciation, depletion and amortization	$ 1.17	$ 0.43	$ 1.13	$ 0.73	$ 0.52	$ 0.71	$ 0.76	$ 0.71	$ 0.75

Our hedging activities resulted in an increase in oil and gas revenues of $11.3 million in 1998, a decrease of $1.7 million in 1999, and a decrease of $30.6 million in 2000.

In January 2001, Chesapeake acquired Gothic with properties primarily located in the Mid-Continent. For the year ended December 31, 2000, Gothic reported $83 million of oil and gas sales and 27 bcfe of production.

Proved Reserves

The following table sets forth our estimated proved reserves and the present value of the proved reserves (based on our weighted average prices at December 31, 2000 of $26.41 per barrel of oil and $10.12 per mcf of gas). These prices were based on the adjusted cash spot prices for oil and natural gas at December 31, 2000.

	Oil (mbbl)	Gas (mmcf)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value ($ in thousands)
Mid-Continent	13,944	883,221	966,887	71%	$4,293,715
Gulf Coast	4,010	133,661	157,719	12	825,891
Canada	—	158,964	158,964	12	680,800
Permian Basin	873	16,209	21,445	2	117,190
Other areas	4,970	19,978	49,798	3	128,432
Total	23,797	1,212,033	1,354,813	100%	$6,046,028

During 2000, we increased the present value of our proved developed reserves to 69% and increased the volume of our proved developed reserves to 70% of total proved reserves. Natural gas reserves accounted for 89% of proved reserves at December 31, 2000.

As a result of the January 2001 acquisition of Gothic, Chesapeake acquired total proved reserves of 302 bcfe at December 31, 2000 with an associated present value of proved reserves of $1.3 billion (based on Gothic's weighted average prices at December 31, 2000 of $26.54 per barrel of oil and $10.19 per mcf of gas). The following reserve data show the combined pro forma proved reserves of Chesapeake and Gothic at

December 31, 2000 (based on combined weighted average prices of $26.42 per barrel of oil and $10.13 per mcf of gas):

	Oil (mbbl)	Gas (mmcf)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value ($ in thousands)
Mid-Continent	15,049	1,140,801	1,231,097	74%	$5,425,407
Gulf Coast	4,010	133,661	157,719	9	825,891
Canada	—	158,964	158,964	10	680,800
Permian Basin	1,536	49,536	58,750	4	252,001
Other areas	4,970	19,978	49,798	3	128,432
Total	25,565	1,502,940	1,656,328	100%	$7,312,531

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, 2000 present value of proved reserve of $62 million and $13 million, respectively; and
- a change in the December 31, 2000 present value of proved reserves for us and Gothic combined of $75 million and $14 million, respectively.

If the present value of our combined pro forma proved reserves were calculated using a more recent approximation of NYMEX spot prices of $24.00 per barrel of oil and $5.00 per mcf of gas, adjusted for our price differentials, the present value of our combined pro forma proved reserves at December 31, 2000 would have been $3.2 billion.

Development, Exploration and Acquisition Expenditures

The following table sets forth information regarding the costs we have incurred in our development, exploration and acquisition activities during the periods indicated:

	Years Ended December 31, 1998	1999	2000
	($ in thousands)		
Development and leasehold costs	$150,241	$124,118	$151,844
Exploration costs	68,672	23,693	24,658
Acquisition costs:			
Proved properties	740,280	52,093	75,285
Unproved properties	26,369	2,747	3,625
Sales of oil and gas properties	(15,712)	(45,635)	(1,529)
Capitalized internal costs	5,262	2,710	6,958
Total	$975,112	$159,726	$260,841

Acreage

The following table sets forth as of December 31, 2000 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 are stated in thousands and 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	1,748,880	676,237	427,289	231,293	2,176,169	907,530
Gulf Coast	225,182	133,595	485,331	436,132	710,513	569,727
Canada	102,838	51,328	638,125	308,719	740,963	360,047
Permian Basin	7,307	4,582	33,717	16,731	41,024	21,313
Other areas	41,049	13,036	607,185	382,738	648,234	395,774
Total	2,125,256	878,778	2,191,647	1,375,613	4,316,903	2,254,391

As of December 31, 2000, Gothic held an interest in approximately 480,000 (229,000 net) acres, almost all of which was in the Mid-Continent.

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 and percentage-of-index contracts or 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. The residue gas and natural gas liquids sold by these purchasers are sold primarily based 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 2000, sales to Aquila Southwest Pipeline Corporation of $54.9 million accounted for 12% of our total oil and gas sales. Management believes that the loss of this customer would not have a material adverse effect on our results of operations or our financial position. No other customer accounted for more than 10% of total oil and gas sales in 2000.

Chesapeake Energy Marketing, Inc., a wholly-owned subsidiary, provides marketing services including commodity price structuring, contract administration and nomination services for Chesapeake, its partners and other oil and natural gas producers in certain geographical areas in which we are active. 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 gas production and to manage fixed 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 semi-annual redeterminations based on current prices at the time of redetermination. In addition, we may have ceiling test writedowns if prices decline significantly from present levels.

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

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

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and gas price movements with any certainty. Declines in oil and gas prices would not only reduce revenue, but could reduce the amount of oil and gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and gas prices do not necessarily move in tandem. Because approximately 91% of our proved reserves are currently natural gas reserves, we are more susceptible to movements in natural gas prices.

Our level of indebtedness may adversely affect operations, and we may have difficulty repaying long-term indebtedness as it matures.

As of December 31, 2000, we had long-term indebtedness of $945 million, which included bank indebtedness of $25 million. Our long-term indebtedness represented 75% of our total capitalization at December 31, 2000. If the Gothic merger had been completed as of December 31, 2000, our long-term indebtedness, on a pro forma basis, would have been $1.16 billion.

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

- a substantial portion of our cash flows must be used to service our indebtedness; for example, for the year ended December 31, 2000, approximately 22% of EBITDA (23% of EBITDA on a pro forma basis for the Gothic acquisition) was used to pay interest on our borrowings. We cannot assure you that our business will generate sufficient cash flows from operations to enable us to continue to meet our obligations under our indentures,
- 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, general corporate or other 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 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 cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future working capital, borrowings or equity financing will 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 and the value of our assets and our performance at the time we need capital.

In addition, our bank borrowing base is subject to semi-annual redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. We cannot assure you that we will 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.

Higher oil and gas prices adversely affect the cost and availability of drilling and production services.

Higher oil and gas prices, such as those we are currently experiencing, generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. We have recently experienced significantly higher costs for drilling rigs and other related services and expect such costs to continue to escalate in 2001.

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 have reduced the realized prices received for our oil and gas sales and these transactions may limit our realized oil and gas sales prices in the future.

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. In 2000, we recorded reductions to oil and gas revenues of $30.6 million related to commodity price risk management activities. We cannot assure you that we will not experience additional reductions to oil and gas revenues from our commodity price risk management. If the hedges in existence at December 31, 2000 had been settled on that date, based upon futures prices as of that date, we would have incurred a loss of $89.3 million, which would have been recognized as price adjustments during the related months of future production. 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 the contracts.

Some of our commodity price 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 risk management transactions exceed certain levels. Our collateral requirement for these activities at December 31, 2000 was $35 million, consisting of $31.5 million in letters of credit and $3.5 million in cash deposits. Future collateral requirements are uncertain, but will depend on arrangements with our counterparties and highly volatile natural gas and oil prices.

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, including those acquired in the Gothic acquisition. 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, 2000, approximately 30% (27% on a pro forma basis for the Gothic acquisition) by volume of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The estimates of these reserves include the assumption that we will make significant capital expenditures to develop the reserves, including $216 million ($235 million on a pro forma basis for the Gothic acquisition) in 2001. Although we have prepared estimates of our oil and gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the results will be as estimated.

You should not assume that the present values referred to in this report 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 combined December 31, 2000 present values pro forma for Gothic are based on combined weighted average oil and gas prices of $26.42 per barrel of oil and $10.13 per mcf of natural gas, compared to our weighted average prices of $24.72 per barrel of oil and $2.25 per mcf of natural gas used in computing Chesapeake's December 31, 1999 present value. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate. A change in price of $0.10 per mcf and $1.00 per barrel would result in:

- a change in our December 31, 2000 present value of proved reserves of $62 million and $13 million, respectively; and
- a change in the December 31, 2000 present value of proved reserves for us and Gothic combined of $75 million and $14 million, respectively.

If the present value of our combined pro forma proved reserves were calculated using a more recent approximation of NYMEX spot prices of $24.00 per barrel of oil and $5.00 per mcf of gas, adjusted for our price differentials, the present value of our combined pro forma proved reserves at December 31, 2000 would have been $3.2 billion.

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 expenses from the development and production of oil and gas properties will affect both the timing of actual future net cash flows from 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 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, our proved reserves will decline over time. In addition, approximately 30% (27% on a pro forma basis for the Gothic acquisition) of our total estimated proved reserves at December 31, 2000 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.

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, debt and equity issuances and the sale of non-core assets. 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 flow from operations is 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.

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 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 which are substantially greater than those available to us. Therefore, we cannot assure you that we will be able to acquire oil and gas properties that contain economically recoverable reserves or that we will 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 than our existing properties, our ability to efficiently realize the economic benefits of such transactions may be limited.

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 occurs, 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. We cannot assure you that the new wells we drill or participate in will be productive or that we will recover all or any portion of our investment in wells drilled. 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
- cost of, or shortages or delays in the availability of, drilling rigs and equipment.

Canadian operations present the risks associated with conducting business outside the United States.

Our operations in Canada are subject to the risks associated with operating outside of the U.S. These risks include the following:

- adverse local political or economic developments,
- exchange controls,
- currency fluctuations,
- royalty and tax increases,
- retroactive tax claims,
- negotiations of contracts with governmental entities, and
- import and export regulations.

In addition, in the event of a dispute, we may be required to litigate the dispute in Canadian courts since we may not be able to sue foreign persons in a U.S. court.

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 and marketing oil and gas production. Our ability to retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business. We have maintained $20 million key man life insurance policies on each of our chief executive officer and chief operating officer but do not intend to renew these policies when they expire on June 1, 2001.

Transactions with executive officers may create conflicts of interest.

Our chief executive officer and chief operating officer, Aubrey K. McClendon and Tom L. Ward, have the right to participate in wells we drill subject to limitations in their employment contracts. As a result of their participation, they routinely have significant accounts payable to us for joint interest billings and other related advances. As of December 31, 2000, Messrs. McClendon and Ward had payables to us of $2.0 million and $2.3 million, respectively, in connection with such participation.

Regulation

General. Numerous departments and agencies, foreign, federal, state and local, issue rules and regulations binding on the oil and gas industry, some of which carry substantial penalties for failure to comply. This regulatory burden increases our cost of doing business and, consequently, affects our profitability.

Exploration and Production. Our domestic operations are subject to various types of regulation at the 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 domestic 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 Canadian operations are subject to similar regulations.

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, foreign, 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. Such regulation has increased the cost of 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, 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. We maintain insurance coverage which we believe is customary in the industry, although we are not fully insured against all environmental risks. 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, 2000, Chesapeake had federal and state income tax net operating loss (NOL) carryforwards of approximately $567 million. Additionally, we had approximately $301 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $5 million of percentage depletion carryforwards. The NOL carryforwards expire from 2009 through 2019. 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 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, 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 ownership changes in January 1995 and March 1998 which triggered limitations. Of the $567 million NOLs and $301 million AMT NOLs, $254 million and $25 million, respectively, are limited under Section 382. Therefore, $313 million of the NOLs and $276 million of the AMT NOLs are not subject to the limitation. The utilization of $254 million of the NOLs and the utilization of $25 million of the AMT NOLs subject to the Section 382 limitation are both limited to approximately $26 million each taxable year. Although no assurances can be made, we do not believe that an additional ownership change has occurred as of December 31, 2000, or will occur as a result of the issuance of the common stock in 2001 related to the acquisition of Gothic. 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 near future. However, there is no assurance that the Internal Revenue Service will not challenge these carryforwards or their utilization.

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. From time to time, Chesapeake's title to oil and gas properties is challenged through legal proceedings. We are routinely involved in litigation involving title to certain of our oil and gas properties, some of which management believes could be adverse to us, individually or in the aggregate. See Item 3 — Legal Proceedings.

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, the occurrence of any of which could result in substantial losses to Chesapeake 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. Chesapeake and our subsidiaries 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 462 full-time employees as of December 31, 2000. No employees are represented by organized labor unions. We believe our employee relations are good.

Facilities

Chesapeake owns an office building complex in Oklahoma City and field offices in Lindsay and Waynoka, Oklahoma; Garden City, Kansas; and Borger, Texas. Chesapeake leases office space in Oklahoma City, Watonga and Weatherford, Oklahoma; Navasota, Texas; and Dickinson, North Dakota.

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.

EBITDA. Net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, impairments of oil and gas properties and other assets, extraordinary items, and certain other non-cash charges. EBITDA is not a measure of cash flow as determined by generally accepted accounting principles. EBITDA information has been included in this report because EBITDA is a measure used by some investors in determining historical ability to service indebtedness. EBITDA should not be considered as an alternative to, or more meaningful than, net income or cash flows as determined in accordance with generally accepted accounting principles as an indicator of operating performance or liquidity.

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° 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.

Operating Cash Flow. The sum of income (loss) before income taxes and extraordinary item, plus oil and gas depreciation, depletion and amortization, plus depreciation and amortization of other assets. Operating cash flow should not be considered as an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with generally accepted accounting principles as an indicator of operating performance or liquidity.

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 four areas: (i) the Mid-Continent (consisting of Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle), representing 71% 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 12% of our proved reserves, (iii) the Helmet area in northeastern British Columbia, representing 12% of our proved reserves, and (iv) the Permian Basin region of southeastern New Mexico, representing 2% of our proved reserves. In addition, we have oil exploration and development programs in portions of North Dakota, Montana, and Saskatchewan, Canada that comprise the Williston Basin.

During the year ended December 31, 2000, we participated in 360 gross (177.3 net) wells, 175 of which we operated. A summary of our drilling activities, capital expenditures and property sales by primary operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Capital Expenditures — Oil and Gas Properties					
			Drilling	Leasehold	Sub-Total	Acquisitions	Sale of Properties	Total
					($ in thousands)			
Mid-Continent	311	149.8	$ 92,087	$17,034	$109,121	$74,320	$(1,239)	$182,202
Gulf Coast	12	6.4	16,982	4,490	21,472	4,590	—	26,062
Canada	14	6.9	11,905	1,664	13,569	—	—	13,569
Permian Basin	13	8.8	10,230	3,398	13,628	—	—	13,628
Other areas	10	5.4	24,960	710	25,670	—	(290)	25,380
Total	360	177.3	$156,164	$27,296	$183,460	$78,910	$(1,529)	$260,841

Chesapeake's proved reserves increased 12% during 2000 to an estimated 1,355 bcfe at December 31, 2000, compared to 1,206 bcfe of estimated proved reserves at December 31, 1999 (see note 11 of notes to consolidated financial statements in Item 8).

Chesapeake's strategy for 2001 is to continue developing our natural gas assets through exploratory and developmental drilling and by selectively acquiring strategic properties in our core operating areas. We have budgeted approximately $310 million for drilling, acreage acquisition, seismic and related capitalized internal costs, and based on our cash flow assumptions, we will have $250 to $325 million available for acquisitions, debt repayment and general corporate purposes. Our budget is frequently adjusted based on changes in oil and gas prices, drilling results, drilling costs and other factors.

Primary Operating Areas

Mid-Continent. Chesapeake's Mid-Continent proved reserves of 967 bcfe represented 71% of our total proved reserves as of December 31, 2000, and this area produced 78.3 bcfe, or 58% of our 2000 production. During 2000, we invested approximately $109.1 million to drill 311 (149.8 net) wells in the Mid-Continent. We anticipate spending approximately 60% to 70% of our total budget for exploration and development activities in the Mid-Continent region during 2001. We anticipate the Mid-Continent will contribute approximately 116 bcfe of production during 2001, or 65% of expected total production.

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 158 bcfe, or 12% of our total proved reserves as of December 31, 2000. During 2000, the Gulf Coast assets produced 35.2 bcfe, or 26% of our total production. During 2000, we invested approximately $21.5 million to drill 12 (6.4 net) wells in the Gulf Coast. In 2001, we anticipate the Gulf Coast will contribute approximately 38 bcfe of production, or 21% of expected total production. We anticipate spending approximately 15% to 20% of our total budget for exploration and development activities in the Gulf Coast region during 2001.

Helmet. Chesapeake's Canadian proved reserves of 159 bcfe represented 12% of our total proved reserves at December 31, 2000. During 2000, production from Canada was 12.1 bcfe, or 9% of our total production. During 2000, we invested approximately $13.6 million to drill 14 (6.9 net) wells, install various pipelines and compressors and to perform capital workovers in Canada. We anticipate spending approximately 9% of our total budget for exploration and development activities in Canada during 2001 and expect production of 15 bcfe in Canada, or 8% of our estimated total production for 2001.

Permian Basin. Chesapeake's Permian Basin proved reserves, consisting primarily of the Lovington area in New Mexico, represented 21 bcfe, or 2% of our total proved reserves as of December 31, 2000. During 2000, the Permian assets produced 6.2 bcfe, or 5% of our total production. We anticipate the Permian Basin will contribute approximately 5 bcfe of production during 2001, or 3% of expected total production. During 2000, we invested approximately $13.6 million to drill 13 (8.8 net) wells in the Permian Basin. For 2001, we anticipate spending approximately 3% to 4% of our total budget for exploration and development activities in the Permian Basin.

Other Operating Areas

In addition to the primary operating areas described above which consist primarily of natural gas properties, Chesapeake maintains operations in the Williston Basin in North Dakota, Montana, and Saskatchewan, Canada which are focused on developing oil properties. In 2000, these areas contributed 2.4 bcfe, or 2% of our total production. In 2001, production levels should increase to approximately 4 bcfe as a result of allocating approximately 2% of our total budget for exploration and development activities in these areas.

Oil and Gas Reserves

The tables below set forth information as of December 31, 2000 with respect to our estimated proved reserves, and the associated estimated future net revenue and the present value at such date. Williamson Petroleum Consultants, Inc. evaluated 31%, Ryder Scott Company L.P. evaluated 25%, and Lee Keeling and Associates evaluated 16% of our combined discounted future net revenues from our estimated proved reserves at December 31, 2000. The remaining 28% 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, 2000	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
Proved developed	15,445	858,463	951,133
Proved undeveloped	8,352	353,570	403,680
Total proved	23,797	1,212,033	1,354,813

Estimated Future Net Revenue as of December 31, 2000(a)	Proved Developed	Proved Undeveloped	Total Proved
		($ in thousands)	
Estimated future net revenue	$7,611,441	$3,091,533	$10,702,974
Present value of future net revenue	$4,184,271	$1,861,757	$ 6,046,028

(a) Estimated future net revenue represents 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, 2000. The amounts shown do not give 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. The prices used in the external and internal reports yield weighted average prices of $26.41 per barrel of oil and $10.12 per mcf of gas.

The future net revenue attributable to our estimated proved undeveloped reserves of $3.1 billion at December 31, 2000, and the $1.9 billion present value thereof, have been calculated assuming that we will expend approximately $300 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 was 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, 2000. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices or that existing contracts will be honored or judicially enforced.

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 represents 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.

As a result of the January 2001 Gothic acquisition, Chesapeake acquired total proved reserves of 302 bcfe, comprised of 255 bcfe of proved developed reserves and 47 bcfe of proved undeveloped reserves. The associated present value of future net revenues is $1.3 billion based on weighted average prices at December 31, 2000 of $26.54 per barrel of oil and $10.19 per mcf of gas. The tables below set forth estimated proved reserves, the associated estimated future net revenue and the present value as of December 31, 2000 for Chesapeake and Gothic combined.

Estimated Proved Reserves as of December 31, 2000	**Oil (mbbl)**	**Gas (mmcf)**	**Total (mmcfe)**
Proved developed	17,012	1,103,935	1,206,007
Proved undeveloped	8,553	399,005	450,321
Total proved	25,565	1,502,940	1,656,328

Estimated Future Net Revenue as of December 31, 2000(a)	**Proved Developed**	**Proved Undeveloped**	**Total Proved**
		($ in thousands)	
Estimated future net revenue	$9,842,538	$3,473,241	$13,315,779
Present value of future net revenue	$5,228,249	$2,084,282	$ 7,312,531

(a) Estimated future net revenue represents 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, 2000. The amounts shown do not give 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. The prices used in the external and internal reports yield weighted average prices of $26.42 per barrel of oil and $10.13 per mcf of gas.

ITEM 3. *Legal Proceedings*

We are subject to ordinary routine litigation incidental to our business. In addition, the following matters were recently terminated or are pending:

Securities Litigation. On March 3, 2000, the U.S. District Court for the Western District of Oklahoma dismissed a consolidated class action complaint styled *In re Chesapeake Energy Corporation Securities Litigation.* On March 21, 2001, the court denied the plaintiffs' motion to amend and supplement their complaint, which had been filed 31 days after the judgment was issued. The complaint, which consolidated 12 purported class action suits filed in August and September 1997, alleged violations of Section 10(b) and Section 20(a) of the Securities Exchange Act of 1934 by Chesapeake and certain of our officers and directors. The action was brought on behalf of purchasers of our common stock and common stock options between January 25, 1996 and June 27, 1997. The complaint alleged that the defendants made material misrepresentations and failed to disclose material facts about our exploration and drilling activities in Louisiana.

Bayard Drilling Technologies, Inc. On July 30, 1998, the plaintiffs in *Yuan, et al. v. Bayard, et al.* filed an amended class action complaint in the U.S. District Court for the Western District of Oklahoma alleging violations of Section 11 and Section 12 of the Securities Act of 1933 and Section 408 of the Oklahoma Securities Act by Chesapeake and others. The action, originally filed in February 1998, was brought purportedly on behalf of investors who purchased Bayard common stock in connection with Bayard's November 1997 initial public offering. The defendants included officers and directors of Bayard who signed the registration statement, selling shareholders (including Chesapeake) and underwriters of the offering. Total proceeds of the offering were $254 million, of which we received net proceeds of $90 million.

The plaintiffs alleged that Chesapeake, a major customer of Bayard's drilling services and the owner of 30.1% of Bayard's outstanding common stock prior to the offering, was a controlling person of Bayard. The plaintiffs asserted that the Bayard prospectus contained material omissions and misstatements that resulted in a decline in Bayard's share price following the public offering. The plaintiffs sought a determination that the suit is a proper class action and damages in an unspecified amount or rescission, together with interest and costs of litigation, including attorneys' fees.

On August 24, 1999, the District Court dismissed the plaintiffs' claims that Chesapeake was a "controlling person" of Bayard under Section 15 of the Securities Act of 1933. As of March 29, 2001, the parties have agreed to settle the action, subject to drafting of documents and court approval after a fairness hearing. Bayard, which was acquired by Nabors Industries, Inc. in April 1999, has reimbursed us for all our costs of defense as incurred. We will have no liability under the terms of the settlement agreement. The case has been administratively closed pending the closing of the settlement.

Patent Litigation. In *Union Pacific Resources Company v. Chesapeake, et al.*, filed in October 1996 in the U.S. District Court for the Northern District of Texas, Fort Worth Division, Union Pacific Resources Company asserted that we had infringed UPRC's patent covering a "geosteering" method utilized in drilling horizontal wells. Following a trial in June 1999, the court ruled on September 21, 1999 that the patent was invalid. Because the patent was declared invalid, the court held that we could not have infringed the patent, dismissed all of UPRC's claims with prejudice and assessed court costs against UPRC. The court concluded that the UPRC patent was invalid for failure to describe definitively the patented method in the patent and for failure to provide sufficient disclosure in the patent to enable one of ordinary skill in the art to practice the patented method. Appeals of the judgment by both Chesapeake and UPRC were denied on January 5, 2001 by the Federal Circuit Court of Appeals. The mandate issued on January 26, 2001. In February 2001, Chesapeake received $89,000 from the plaintiff for reimbursement of court costs.

West Panhandle Field Cessation Cases. One of our subsidiaries, Chesapeake Panhandle Limited Partnership ("CP") (f/k/a MC Panhandle, Inc.), and two subsidiaries of Kinder Morgan, Inc. have been defendants in 13 lawsuits filed between June 1997 and January 1999 by royalty owners seeking the cancellation of oil and gas leases in the West Panhandle Field in Texas. MC Panhandle, Inc., which we acquired in April 1998, has owned the leases since January 1, 1997. The co-defendants are prior lessees.

The plaintiffs in these cases have claimed the leases terminated upon the cessation of production for various periods, primarily during the 1960s. In addition, the plaintiffs have sought to recover conversion damages, exemplary damages, attorneys' fees and interest. The defendants have asserted that any cessation of production was excused and have pled affirmative defenses of limitations, waiver, temporary estoppel, laches and title by adverse possession. As previously reported, four of the 13 cases have been tried, and there have been appellate decisions in three of them.

On January 12, 2001, CP and the other defendants entered into a settlement agreement with the plaintiffs in eight of ten cases tried or pending in the U.S. District Court of Moore County, Texas, 69th Judicial District. The terms of the settlement are confidential but we have determined that our portion of the settlement consideration is not material to our financial condition or results of operations. Only the claims of certain involuntary plaintiffs joined in these settled cases remain and we do not consider these claims to be material.

Related West Panhandle cessation cases which are pending are the following:

Lois Law, et al. v. NGPL, et al., U.S. District Court of Moore County, Texas, 69th Judicial District, No. 97-70, filed December 22, 1997, jury trial in June 1999, verdict for CP and co-defendants. The jury found plaintiffs' claims were barred by adverse possession, laches and revivor. On January 19, 2000, the court granted plaintiffs' motion for judgment notwithstanding verdict and entered judgment in favor of plaintiffs. In addition to quieting title to the lease (including existing gas wells and all attached equipment) in plaintiffs, the court awarded actual damages against CP in the amount of $716,400 and exemplary damages in the amount of $25,000. The court further awarded, jointly and severally from all defendants, $160,000 in attorneys' fees and interest and court costs. On March 28, 2001, the Amarillo Court of Appeals reversed and rendered the judgement in favor of CP and the other defendants, finding that the subject leases had been revived as a matter of law, making all other issues moot.

A.C. Smith, et al. v NGPL, et al., U.S. District Court of Moore County, Texas, 69th Judicial District, No. 98-47, first filed January 26, 1998, refiled May 29, 1998. On June 18, 1999, the court granted plaintiffs' motion for summary judgment in part, finding that the lease had terminated due to the cessation of production, subject to the defendants' affirmative defenses. On February 8, 2001, the court granted plaintiffs' motion for summary judgment on defendants' affirmative defenses but reversed its ruling that the lease had terminated as a matter of law. No trial date has been set.

Phillip Thompson, et al. v. NGPL, et al., U.S. District Court, Northern District of Texas, Amarillo Division, Nos. 2:98-CV-012 and 2:98-CV-106, filed January 8, 1998 and March 18, 1998, respectively (actions consolidated), jury trial in May 1999, verdict for CP and co-defendants. The jury found plaintiffs' claims were barred by the payment of shut-in royalties, laches and revivor. Plaintiffs' motion for new trial pending.

Craig Fuller, et al. v. NGPL, et al., U.S. District Court of Carson County, Texas, 100th Judicial District, No. 8456, filed June 23, 1997, cross motions for summary judgment pending.

Pace v. NGPL, et al., U.S. District Court, Northern District of Texas, Amarillo Division, filed January 29, 1999. Cross motions for summary judgment pending.

We have previously established an accrued liability we believe will be sufficient to cover the estimated costs of litigation for each of the pending cases and the settlement consideration under the terms of the settlement agreement mentioned above. Because of the inconsistent verdicts reached by the juries in the four 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 the amount of damages that might ultimately be awarded could differ from management's estimates. CP and the other defendants intend to vigorously defend against the plaintiffs' claims.

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, 1999:		
First Quarter	$ 1.50	$ 0.63
Second Quarter	2.94	1.31
Third Quarter	4.13	2.75
Fourth Quarter	3.88	2.13
Year ended December 31, 2000:		
First Quarter	3.31	1.94
Second Quarter	8.00	2.75
Third Quarter	8.25	5.31
Fourth Quarter	10.50	5.44

At March 26, 2001 there were 1,175 holders of record of our common stock and approximately 37,600 beneficial owners.

Dividends

We did not pay dividends on our common stock in 1999 or 2000. The payment of future cash dividends, if any, will depend upon, among other things, our financial condition, funds from operations, the level of our capital and development expenditures, our future business prospects and any contractual restrictions. Other than payments of dividends on preferred stock, our current policy is to retain cash for the continued growth of our business.

Two 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 the 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.

From December 31, 1998 through March 31, 2000, we did not meet the debt incurrence test contained in one of our indentures that requires our coverage ratio of adjusted consolidated EBITDA to adjusted consolidated interest expense to be at least 2.5 to 1. As a result, we were unable to pay dividends on our existing preferred stock. Beginning June 30, 2000, we met the debt incurrence test, and resumed paying quarterly preferred stock dividends on November 1, 2000. As of December 31, 2000, our coverage ratio, as calculated in accordance with our most restrictive senior indenture, was 4.4 to 1.

The indenture for Gothic Production's senior secured notes significantly limits the transfer of funds held by Gothic to Chesapeake in the form of cash dividends, loans or advances.

ITEM 6. *Selected Financial Data*

The following table sets forth selected consolidated financial data of Chesapeake for the fiscal year ended June 30, 1997, the six months ended December 31, 1996, the six month transition period ended December 31, 1997 and the twelve months ended December 31, 1997, 1998, 1999 and 2000. The data are derived from our audited consolidated financial statements, although the periods for the six months ended December 31, 1996 and the twelve months ended December 31, 1997 have not been audited. Acquisitions we made during the first and second quarters of 1998 materially affect the comparability of the selected financial data for 1997 and 1998. Each of the acquisitions 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.

	Year Ended June 30,	Six Months Ended December 31,		Years Ended December 31,			
	1997	1996	1997	1997	1998	1999	2000
		(unaudited)		(unaudited)			
	($ in thousands, except per share data)						
Statement of Operations Data:							
Revenues:							
Oil and gas sales	$ 192,920	$ 90,167	$ 95,657	$ 198,410	$ 256,887	$ 280,445	$ 470,170
Oil and gas marketing sales	76,172	30,019	58,241	104,394	121,059	74,501	157,782
Total revenues	269,092	120,186	153,898	302,804	377,946	354,946	627,952
Operating costs:							
Production expenses	11,445	4,268	7,560	14,737	51,202	46,298	50,085
Production taxes	3,662	1,606	2,534	4,590	8,295	13,264	24,840
General and administrative	8,802	3,739	5,847	10,910	19,918	13,477	13,177
Oil and gas marketing expenses	75,140	29,548	58,227	103,819	119,008	71,533	152,309
Oil and gas depreciation, depletion and amortization	103,264	36,243	60,408	127,429	146,644	95,044	101,291
Depreciation and amortization of other assets	3,782	1,836	2,414	4,360	8,076	7,810	7,481
Impairment of oil and gas properties	236,000	—	110,000	346,000	826,000	—	—
Impairment of other assets	—	—	—	—	55,000	—	—
Total operating costs	442,095	77,240	246,990	611,845	1,234,143	247,426	349,183
Income (loss) from operations	(173,003)	42,946	(93,092)	(309,041)	(856,197)	107,520	278,769
Other income (expense):							
Interest and other income	11,223	2,516	78,966	87,673	3,926	8,562	3,649
Interest expense	(18,550)	(6,216)	(17,448)	(29,782)	(68,249)	(81,052)	(86,256)
Total other income (expense)	(7,327)	(3,700)	61,518	57,891	(64,323)	(72,490)	(82,607)
Income (loss) before income taxes and extraordinary item	(180,330)	39,246	(31,574)	(251,150)	(920,520)	35,030	196,162
Provision (benefit) for income taxes	(3,573)	14,325	—	(17,898)	—	1,764	(259,408)
Income (loss) before extraordinary item	(176,757)	24,921	(31,574)	(233,252)	(920,520)	33,266	455,570
Extraordinary item:							
Loss on early extinguishment of debt, net of applicable income taxes	(6,620)	(6,443)	—	(177)	(13,334)	—	—
Net income (loss)	(183,377)	18,478	(31,574)	(233,429)	(933,854)	33,266	455,570
Preferred stock dividends	—	—	—	—	(12,077)	(16,711)	(8,484)
Gain on redemption of preferred stock	—	—	—	—	—	—	6,574
Net income (loss) available to common shareholders	$(183,377)	$ 18,478	$ (31,574)	$(233,429)	$ (945,931)	$ 16,555	$ 453,660
Earnings (loss) per common share — basic:							
Income (loss) before extraordinary item	$ (2.69)	$ 0.40	$ (0.45)	$ (3.30)	$ (9.83)	$ 0.17	$ 3.52
Extraordinary item	(0.10)	(0.10)	—	—	(0.14)	—	—
Net income (loss)	$ (2.79)	$ 0.30	$ (0.45)	$ (3.30)	$ (9.97)	$ 0.17	$ 3.52
Earnings (loss) per common share — assuming dilution:							
Income (loss) before extraordinary item	$ (2.69)	$ 0.38	$ (0.45)	$ (3.30)	$ (9.83)	$ 0.16	$ 3.01
Extraordinary item	(0.10)	(0.10)	—	—	(0.14)	—	—
Net income (loss)	$ (2.79)	$ 0.28	$ (0.45)	$ (3.30)	$ (9.97)	$ 0.16	$ 3.01
Cash dividends declared per common share	$ 0.02	$ —	$ 0.04	$ 0.06	$ 0.04	$ —	$ —
Cash Flow Data:							
Cash provided by operating activities before changes in working capital	$ 161,140	$ 76,816	$ 67,872	$ 152,196	$ 117,500	$ 138,727	$ 305,804
Cash provided by operating activities	84,089	41,901	139,157	181,345	94,639	145,022	314,640
Cash used in investing activities	523,854	184,149	136,504	476,209	548,050	159,773	330,036
Cash provided by (used in) financing activities	512,144	231,349	(2,810)	277,985	363,797	18,967	(22,933)
Effect of exchange rate changes on cash	—	—	—	—	(4,726)	4,922	(329)
Balance Sheet Data (at end of period):							
Total assets	$ 949,068	$ 860,597	$ 952,784	$ 952,784	$ 812,615	$ 850,533	$1,440,426
Long-term debt, net of current maturities	508,950	220,149	508,992	508,992	919,076	964,097	944,845
Stockholders' equity (deficit)	286,889	484,062	280,206	280,206	(248,568)	(217,544)	313,232

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,		
	1998	1999	2000
Net Production:			
Oil (mbbl)	5,976	4,147	3,068
Gas (mmcf)	94,421	108,610	115,771
Gas equivalent (mmcfe)	130,277	133,492	134,179
Oil and Gas Sales ($ in thousands):			
Oil	$ 75,877	$ 66,413	$ 80,953
Gas	181,010	214,032	389,217
Total oil and gas sales	$256,887	$280,445	$470,170
Average Sales Price:			
Oil ($ per bbl)	$ 12.70	$ 16.01	$ 26.39
Gas ($ per mcf)	$ 1.92	$ 1.97	$ 3.36
Gas equivalent ($ per mcfe)	$ 1.97	$ 2.10	$ 3.50
Expenses ($ per mcfe):			
Production expenses and taxes	$ .45	$ .45	$ .56
General and administrative	$ .15	$ .10	$ .10
Depreciation, depletion and amortization	$ 1.13	$ .71	$ .75
Net Wells Drilled:			
Horizontal wells	20	11	10
Vertical wells	116	109	167
Net Wells at End of Period	2,405	2,242	2,697

Results of Operations

Years Ended December 31, 1998, 1999 and 2000.

General. For the year ended December 31, 2000, Chesapeake had net income of $456 million, or $3.01 per diluted common share, on total revenues of $628 million. This compares to net income of $33 million, or $0.16 per diluted common share, on total revenues of $355 million during the year ended December 31, 1999, and a net loss of $934 million, or a loss of $9.97 per diluted common share, on total revenues of $378 million during the year ended December 31, 1998. Net income in 2000 was significantly enhanced by the reversal of a deferred tax valuation allowance in the amount of $265 million during the fourth quarter. The reversal related to Chesapeake's ability to generate sufficient future taxable income to utilize net operating losses prior to their expiration. The loss in 1998 was caused primarily by an $826 million oil and gas property writedown recorded under the full-cost method of accounting and a $55 million writedown of other assets. See "Impairment of Oil and Gas Properties" and "Impairment of Other Assets."

Oil and Gas Sales. During 2000, oil and gas sales increased to $470.2 million versus $280.4 million in 1999 and $256.9 million in 1998. In 2000, Chesapeake produced 134.2 bcfe at a weighted average price of $3.50 per mcfe, compared to 133.5 bcfe produced in 1999 at a weighted average price of $2.10 per mcfe, and 130.3 bcfe produced in 1998 at a weighted average price of $1.97 per mcfe.

The following table shows our production by region for 1998, 1999 and 2000:

	Years Ended December 31,					
	1998		1999		2000	
	mmcfe	Percent	mmcfe	Percent	mmcfe	Percent
Mid-Continent	61,930	48%	68,170	51%	78,342	58%
Gulf Coast	52,793	40	43,909	33	35,154	26
Canada	7,746	6	11,737	9	12,076	9
Permian Basin	3,939	3	5,722	4	6,166	5
Other areas	3,869	3	3,954	3	2,441	2
Total production	130,277	100%	133,492	100%	134,179	100%

Natural gas production represented approximately 86% of our total production volume on an equivalent basis in 2000, compared to 81% in 1999 and 72% in 1998. The decrease in oil production from 1998 through 2000 is the result of divestitures that occurred primarily in 1999 and our increasing focus on natural gas.

For 2000, we realized an average price per barrel of oil of $26.39, compared to $16.01 in 1999 and $12.70 in 1998. Natural gas price realizations fluctuated from an average of $1.92 per mcf in 1998 and $1.97 in 1999 to $3.36 per mcf in 2000. In 2000, our hedging activities resulted in a decrease in oil and gas revenues of $30.6 million or $0.23 per mcfe, a decrease of $1.7 million or $0.01 per mcfe in 1999, and an increase of $11.3 million or $0.09 per mcfe in 1998.

Oil and Gas Marketing Sales. Chesapeake realized $157.8 million in oil and gas marketing sales for third parties in 2000, with corresponding oil and gas marketing expenses of $152.3 million, for a net margin of $5.5 million. This compares to sales of $74.5 million and $121.1 million, expenses of $71.5 million and $119.0 million, and a margin of $3.0 million and $2.1 million in 1999 and 1998, respectively. The increase in marketing sales and cost of sales in 2000 as compared to 1999 and 1998 was due primarily to higher oil and gas prices in 2000 and the fact that we began marketing oil in June 1999.

Production Expenses and Taxes. Production expenses and taxes, which include lifting costs, production taxes and ad valorem taxes, were $74.9 million in 2000, compared to $59.6 million and $59.5 million in 1999 and 1998, respectively. On a unit of production basis, production expenses and taxes were $0.56 per mcfe in 2000 and $0.45 per mcfe in 1999 and 1998. The increase in costs on a per unit basis in 2000 is due primarily to higher production taxes resulting from higher oil and gas prices. 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 that lease operating expenses per mcfe will generally remain at current levels throughout 2001, although production taxes will fluctuate with changes in oil and gas prices.

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 $13.2 million in 2000, $13.5 million in 1999 and $19.9 million in 1998. The decrease in 1999 compared to 1998 was due primarily to various actions taken to lower corporate overhead, including staff reductions and office closings which occurred in late 1998 and early 1999. We capitalized $7.0 million, $2.7 million and $5.3 million of internal costs in 2000, 1999 and 1998, respectively, directly related to our oil and gas exploration and development efforts. We anticipate that general and administrative expenses for 2001 per mcfe will remain at approximately the same level as 2000.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties was $101.3 million, $95.0 million and $146.6 million during 2000, 1999 and 1998, 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 $0.75 ($0.76 in U.S. and $0.71 in Canada), $0.71 ($0.73 in U.S. and $0.52 in Canada), and $1.13 ($1.17 in U.S. and $0.43 in Canada) in 2000, 1999 and 1998, respectively. We expect the 2001 DD&A rate to be between $1.00 and $1.05 per mcfe.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $7.5 million in 2000, compared to $7.8 million in 1999 and $8.1 million in 1998.

Impairment of Oil and Gas Properties. We use the full-cost method to account for our investment in oil and gas properties. Under this method, all costs of acquisition, exploration and development of oil and gas reserves (including such costs as leasehold acquisition costs, geological and geophysical expenditures, certain capitalized internal costs, dry hole costs and tangible and intangible development costs) are capitalized as incurred. These oil and gas property costs, along with the estimated future capital expenditures to develop proved undeveloped reserves, are depleted and charged to operations using the unit-of-production method based on the ratio of current production to proved oil and gas reserves as estimated by our independent engineering consultants and our internal reservoir engineers. Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the property or whether impairment has occurred. The excess of capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes, over the discounted future net revenues of proved oil and gas properties is charged to operations.

We incurred an impairment of oil and gas properties charge of $826 million in 1998. No such charge was incurred in 2000 or 1999. The 1998 writedown was caused primarily by the significant decreases in oil and gas prices throughout 1998. Oil and gas prices used to value our proved reserves decreased from $17.62 per bbl of oil and $2.29 per mcf of gas at December 31, 1997, to $10.48 per bbl of oil and $1.68 per mcf of gas at December 31, 1998. Higher drilling and completion costs and the evaluation of certain leasehold, seismic and other exploration-related costs that were previously unevaluated were additional factors which contributed to the writedown in 1998.

Impairment of Other Assets. Chesapeake incurred a $55 million other asset impairment charge during 1998. Of this amount, $30 million related to our investment in preferred stock of Gothic Energy Corporation and the remainder was related to certain of our gas processing and transportation assets located in Louisiana. No such charge was recorded in 2000 or 1999.

Interest and Other Income. Interest and other income was $3.6 million, $8.6 million and $3.9 million in 2000, 1999 and 1998, respectively. The increase in 1999 was due primarily to gains on sales of various non-oil and gas assets during 1999 which did not occur in 2000 and 1998.

Interest Expense. Interest expense increased to $86.3 million in 2000, compared to $81.1 million in 1999 and $68.2 million in 1998. The increase in 2000 is due to additional borrowings under our bank credit facility. The increase in 1999 compared to 1998 is due primarily to a full year of interest on our $500 million senior notes issued in April 1998. In addition to the interest expense reported, we capitalized $2.4 million of interest during 2000, compared to $3.5 million capitalized in 1999, and $6.5 million capitalized in 1998. We anticipate that capitalized interest for 2001 will be between $2.0 million and $3.0 million.

Provision (Benefit) for Income Taxes. Chesapeake recorded an income tax benefit of $259.4 million in 2000 compared to income tax expense of $1.8 million in 1999 and none in 1998. The income tax benefit 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 recent results of operations, the improved outlook for the natural gas industry and our projected results of future operations, we believe it is more likely than not that Chesapeake will be able to generate sufficient future taxable income to utilize our existing NOLs prior to their expiration. Consequently, management has determined that a valuation allowance is no longer required. The income tax expense recorded in 1999 is related entirely to our Canadian operations.

Liquidity and Capital Resources

Years Ended December 31, 1998, 1999 and 2000

Cash Flows from Operating Activities. Cash provided by operating activities (inclusive of changes in working capital) was $314.6 million in 2000, compared to $145.0 million in 1999 and $94.6 million in 1998.

The $169.6 million increase from 1999 to 2000 and the $50.4 million increase from 1998 to 1999 were due primarily to increased oil and gas revenues resulting from higher prices.

Cash Flows from Investing Activities. Cash used in investing activities increased to $330.0 million in 2000, compared to $159.8 million in 1999 and $548.1 million in 1998. During 2000, Chesapeake invested $188.8 million for exploration and development drilling, $78.9 million for the acquisition of oil and gas properties, and received $1.5 million related to divestitures of oil and gas properties. During 2000, we invested $36.7 million in the purchase of Gothic notes and acquisition related costs. Also in 2000, we invested $7.9 million in Advanced Drilling Technologies, L.L.C., a 50% owned drilling company joint venture. Additionally in 2000, we invested $4.0 million to construct a new building at our Oklahoma City complex. We anticipate the availability of this additional office space will reduce our general and administrative costs in future years. In 1999, we invested $153.3 million for exploration and development drilling, $49.9 million for the acquisition of oil and gas properties, and received $45.6 million related to divestitures of oil and gas properties. During 1998, $279.9 million was used to acquire certain oil and gas properties and companies with oil and gas reserves. During 1998, we invested $259.7 million for exploratory and developmental drilling. Also during 1998, we sold our 19.9% stake in Pan East Petroleum Corp. to Poco Petroleums, Ltd. for approximately $21.2 million.

Cash Flows from Financing Activities. Cash used in financing activities was $22.9 million in 2000, compared to cash provided of $19.0 million in 1999 and $363.8 million in 1998. During 2000, we made additional borrowings under our bank credit facility of $244.0 million and made repayments under this facility of $262.5 million. Also in 2000, we paid $8.3 million in connection with an exchange 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, we received $7.1 million cash from the sellers of Gothic notes pursuant to make-whole provisions included in the purchase agreements. These provisions required payments to be made by the sellers to us or additional payments to be made by us to the sellers, depending upon changes in market value of our common stock during a specified period pending registration of our common stock issued to the sellers of Gothic notes. During 1999, we made additional borrowings under our bank credit facility of $116.5 million and made repayments under this facility of $98.0 million. During 1998, we retired $85 million of debt assumed at the completion of the DLB Oil & Gas, Inc. acquisition, $120 million of debt assumed at the completion of the Hugoton Energy Corporation acquisition, $90 million of senior notes, and $170 million of borrowings made under our bank credit facility. Also during 1998, we issued $500 million in senior notes and $230 million in preferred stock. We also repurchased common stock and preferred stock for $30 million.

Financial Flexibility and Liquidity

Chesapeake had working capital of $4.2 million at December 31, 2000 including a restricted cash balance of $3.5 million. We have a $100 million revolving bank credit facility which matures in July 2002, with a committed borrowing base of $100 million. As of December 31, 2000, we had borrowed $25 million under this facility and had $31.5 million of the facility securing various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at a variable rate, which was 9.3% per annum as of December 31, 2000. Interest is payable quarterly calculated at .50% to 1.25%, depending on utilization, plus the higher of (a) the Union Bank of California reference rate or (b) the federal funds rate plus .50% per year. We may elect to convert a portion of our borrowings to interest calculated under a London Interbank Offered Rate (LIBOR) plus 2.00% to 2.75%, depending on utilization. We are required to pay a commitment fee on the unused portion of the borrowing base equal to 0.375% per annum due quarterly.

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 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 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 $3.2 million of costs for the standby facility.

At December 31, 2000, our senior notes represented $919 million of our $945 million of long-term debt. Debt ratings for the senior notes are B2 by Moody's Investors Service and B+ by Standard & Poor's Ratings Services as of January 2001. There are no scheduled principal payments required on any of the senior notes until 2004, 2005, and thereafter, when $150 million, $500 million and $269 million, respectively, are due.

As of March 28, 2001, Chesapeake has purchased and subsequently retired $7.3 million of the $150 million 8.5% senior notes for total consideration of $7.4 million, including accrued interest of $0.2 million.

Chesapeake's senior note indentures restrict the ability of Chesapeake and our restricted subsidiaries to incur additional indebtedness. As of December 31, 2000, we estimate that secured commercial bank indebtedness of $681 million could have been incurred within these restrictions. The Chesapeake indenture restrictions do not apply to our unrestricted subsidiaries, Chesapeake Energy Marketing, Inc. and Gothic Energy Corporation and its subsidiary.

Chesapeake's senior note indentures also limit our ability to make restricted payments (as defined), including the payment of cash dividends, unless certain tests are met. From December 31, 1998 through March 31, 2000, we were unable to meet the requirements to incur additional unsecured indebtedness, and consequently were restricted from paying cash dividends on our 7% cumulative convertible preferred stock. On September 22, 2000, we declared a regular quarterly dividend and a special dividend equal to all unpaid dividends on our preferred stock both payable November 1, 2000 to shareholders of record on October 16, 2000. A total combined dividend of $7.444 per outstanding preferred share was paid November 1, 2000, eliminating the accumulated unpaid dividends.

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 preferred stock. These transactions reduced the number of preferred shares outstanding from 4.6 million to 0.6 million, and reduced the liquidation value of shares of outstanding preferred stock from $229.8 million to $31.2 million. In addition, these transactions eliminated $22.9 million of dividends in arrears during 2000. 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 for the year ended December 31, 2000. Chesapeake has called for redemption all the outstanding shares of preferred stock for $52.45 per share, plus accumulated and unpaid dividends, on May 1, 2001 pursuant to the optional redemption provisions of the certificate of designation for the preferred stock. Other than the redemption premium, which will be paid in cash, we intend to use our common stock to redeem any shares of the outstanding preferred stock that are not converted into common stock prior to the redemption date.

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 described above. 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). Gothic redeemed all remaining outstanding senior secured discount notes on March 12, 2001 for total cash consideration of $243,000 pursuant to the optional make-whole redemption provisions of the indenture.

In 2000, Chesapeake purchased $31.6 million of the 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 described above. Through the make-whole provisions, Chesapeake received $1.0 million in cash. In February 2001, Chesapeake purchased $1.0 million principal amount of Gothic senior secured notes tendered at 101%. The notes purchased in 2000 and those tendered pursuant to the change-of-control offer to purchase, representing a total of $32.7 million principal amount, were retired and cancelled in February 2001.

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 March 15, 2001, 1.1 million shares of Chesapeake common stock may be purchased upon the exercise of such warrants and options at an average price of $12.28 per share.

Gothic Production Corporation's senior secured notes, of which $202.3 million principal amount remains presently outstanding, have been guaranteed by its parent Gothic Energy Corporation. Chesapeake has not assumed any payment obligations with respect to the notes. The notes are collateralized by Gothic Production's oil and gas properties and mature on May 1, 2005. The notes may be redeemed beginning May 1, 2002 at an initial redemption price of 105.563%. At any time prior to May 1, 2002, Gothic may, at its option, redeem all or any portion of the senior secured notes at the make-whole price (as defined in the senior note indenture) plus accrued or unpaid interest to the date of redemption. The indenture for the notes contains covenants imposing restrictions on the incurrence of additional indebtedness, the payment of dividends, distributions and other restricted payments (including such payments to Chesapeake), the sale of assets, the creation of liens and transactions with affiliates, among other covenants. Gothic Production will continue to operate in accordance with the terms of the senior secured note indenture. Gothic will produce its existing oil and gas properties but will not add to its reserves through drilling or acquisitions. As a result of the acquisition, Chesapeake will develop all future wells. Chesapeake has assumed operations of all properties formerly operated by Gothic Production.

We believe we have adequate resources, including budgeted cash flow from operations, to fund our capital expenditure budget for exploration and development activities during 2001, which are currently estimated to be approximately $310 million. However, lower oil and gas prices, 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 to have an additional $250 to $325 million available for acquisitions, debt repayment and general corporate purposes in 2001. Additionally, we have approximately $70 million available under our bank credit facility as of March 30, 2001.

We will have additional cash needs to fund our future operations. If we do not have cash available, or borrowing capacity under our credit facilities when a cash need arises, we would be forced to seek additional debt or equity financing or to forego the opportunity. In the event that we determine to seek additional debt or equity financing, there can be no assurance that any such financing will be available, on commercially reasonable terms or at all, or permitted by the terms of our existing indebtedness.

On March 29, 2001, we announced a proposed private offering to sell $800 million of senior notes due 2011 in order to lower the interest rate and extend the maturity of approximately 74% of our senior notes. If the offering is successfully completed, the proceeds from the proposed offering, together with available cash and bank borrowings, would be used to redeem Chesapeake's existing $120 million principal amount of 9.125% senior notes due 2006, $500 million principal amount of 9.625% senior notes due 2005 and $202.5 million principal amount of 11.125% senior secured notes due 2005 of Gothic Production Corporation, a Chesapeake subsidiary. Redemption of these notes will include payment of aggregate make-whole and redemption premiums estimated at approximately $74 million. The notes to be offered by Chesapeake would not be initially registered under the Securities Act of 1933, as amended, and will not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

Recently Issued Accounting Standards

On June 15, 1998, the Financial Accounting Standards Board issued SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* SFAS 133 establishes a new model for accounting for derivatives and hedging activities and supersedes and amends a number of existing standards. SFAS 133 (as amended by SFAS 137 and SFAS 138) is effective for all fiscal quarters of fiscal years beginning after June 15, 2000.

SFAS 133 standardizes the accounting for derivative instruments by requiring that all derivatives be recognized as assets and liabilities and measured at fair value. The accounting for changes in the fair value of derivatives (gains and losses) depends on (i) whether the derivative is designated and qualifies as a hedge, and

(ii) the type of hedging relationship that exists. Changes in the fair value of derivatives that are not designated as hedges or that do not meet the hedge accounting criteria in SFAS 133 are required to be reported in earnings. In addition, all hedging relationships must be designated, reassessed and documented pursuant to the provisions of SFAS 133. We will fully adopt SFAS 133 on January 1, 2001, the effective date as amended by SFAS 138. SFAS 133 is expected to increase volatility of stockholders' equity, reported earnings (losses) and other comprehensive income. If we had adopted SFAS 133 on December 31, 2000, Chesapeake would have recorded an additional $9.3 million in current assets and $98.6 million in current liabilities related to our existing oil and gas hedges based on the forward price curve in effect at December 31, 2000. The net liability of $89.3 million related to qualifying hedge instruments would have been charged to other comprehensive income which appears in the equity section of the balance sheet. After adoption, Chesapeake will be required to recognize any hedge ineffectiveness in the income statement each period.

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.

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,
- our commodity price risk management activities,
- our ability to replace reserves,
- the availability of capital,
- uncertainties inherent in estimating quantities of oil and gas reserves,
- projecting future rates of production and the timing of development expenditures,
- uncertainties in evaluating oil and gas reserves of acquired properties and associated potential liabilities,
- 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,
- the strength and financial resources of our competitors,
- the loss of officers or key employees, and
- conflicts of interest our chief executive officer and chief operating officer may have as a result of their participation in company wells and their substantial stock ownership.

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 SEC 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*

Commodity Price Risk

Chesapeake's results of operations are highly dependent upon the prices received for oil and natural gas production.

Hedging Activities

Periodically Chesapeake utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include:

- swap arrangements that establish an index-related price above which we pay the counterparty and below which we are paid by the counterparty (counterparty payments in some contracts are subject to a cap),
- the purchase of index-related puts that provide for a "floor" price below which the counterparty pays us the amount by which the price of the commodity is below the contracted floor,
- the sale of index-related calls that provide for a "ceiling" price above which we pay the counterparty the amount by which the price of the commodity is above the contracted ceiling,
- basis protection swaps, which are arrangements that guarantee the price differential of oil or gas from a specified delivery point or points, and
- collar arrangements that establish an index-related price below which the counterparty pays us and a separate index-related price above which we pay the counterparty.

Commodity markets are volatile, and as a result, our hedging activity is dynamic. As market conditions warrant, we may elect to settle a hedging transaction prior to its scheduled maturity date and, as a result, realize a gain or loss on the transaction.

Results from commodity hedging transactions are reflected in oil and gas sales to the extent related to our oil and gas production. We only enter into commodity hedging transactions related to our oil and gas production volumes or physical purchase or sale commitments of our marketing subsidiary. Gains or losses on crude oil and natural gas hedging transactions are recognized as price adjustments in the months of related production.

As of December 31, 2000, we had the following open natural gas swap arrangements designed to hedge a portion of our domestic gas production for periods after December 2000:

Months	Volume (mmbtu)	NYMEX-Index Strike Price (per mmbtu)
January 2001	4,960,000	$6.03
February 2001	5,320,000	6.12
March 2001	4,650,000	5.11
April 2001	5,100,000	4.79
May 2001	5,270,000	4.63
June 2001	3,900,000	4.61
July 2001	4,030,000	4.59
August 2001	4,030,000	4.58
September 2001	3,900,000	4.57
October 2001	620,000	4.80

If the swap arrangements listed above had been settled on December 31, 2000, we would have incurred a loss of $80.1 million. Subsequent to December 31, 2000, we settled the natural gas swaps for January, February and March 2001. A loss of $18.6 million and $4.4 million and a gain of $0.1 million will be recognized as price adjustments in January, February and March, respectively. If we had settled the remaining swaps (April through October) using March 21, 2001 prices, we would have incurred a loss of $13.5 million.

On June 2, 2000, we entered into a natural gas basis protection swap transaction for 13,500,000 mmbtu for the period of January 2001 through March 2001. This transaction requires that the counterparty pay us if the NYMEX price exceeds the Houston Ship Channel Beaumont/Texas Index by more than $0.0675 for each of the related months of production. If the NYMEX price less $0.0675 does not exceed the Houston Ship Channel Beaumont/Texas Index for each month, we will pay the counterparty. Gains or losses on basis swap transactions are recognized as price adjustments in the month of related production. Subsequent to December 31, 2000, we settled the natural gas basis protection swaps for January, February and March 2001. A gain of $0.3 million, a loss of $0.1 million and a loss of $0.5 million will be recognized as price adjustments in January, February and March, respectively.

As of December 31, 2000, we had open natural gas collar transactions designed to hedge 60,000 mmbtu per day throughout 2001 at an average NYMEX-defined high strike price (cap) of $6.08 per mmbtu and an average NYMEX-defined low strike price (floor) of $4.00 per mmbtu. If the collar transactions had been settled on December 31, 2000, we would have incurred a loss of $18.5 million. Subsequent to December 31, 2000, we settled the natural gas collar transactions for January, February and March 2001. A loss of $6.9 million and $1.4 million will be recognized as price adjustments in January and February, respectively. The March 2001 contract was settled for no gain or loss.

As of December 31, 2000, we had the following open crude oil swap arrangements designed to hedge a portion of our domestic crude oil production for periods after December 2000:

Months	Volume (bbls)	NYMEX-Index Strike Price (per bbl)
January 2001	165,000	$29.97
February 2001	150,000	29.92
March 2001	165,000	29.84
April 2001	160,000	29.80
May 2001	165,000	29.75
June 2001	160,000	29.71
July 2001	165,000	29.68
August 2001	165,000	29.65
September 2001	160,000	29.62
October 2001	165,000	29.59
November 2001	160,000	29.56
December 2001	165,000	29.54

If the swap arrangements listed above had been settled on December 31, 2000, we would have realized a gain of $9.3 million. Subsequent to December 31, 2000, we settled the crude oil swap for January 2001 for a gain of $0.1 million and February 2001 for a gain of $41,350, which will be recognized as a price adjustment in January and February 2001.

Subsequent to December 31, 2000, we entered into the following natural gas swap arrangements designed to hedge a portion of our domestic gas production for periods after December 2000:

Months	Volume (mmbtu)	NYMEX-Index Strike Price (per mmbtu)
March 2001	310,000	$5.93
April 2001	300,000	5.66
May 2001	930,000	5.34
June 2001	900,000	5.37
July 2001	930,000	5.40
August 2001	930,000	5.42
September 2001	900,000	5.38
October 2001	1,240,000	5.40

The natural gas swap for March 2001 was settled for a gain of $0.3 million which will be recognized as a price adjustment in March 2001. If we had settled the remaining swaps (April through October) using March 21, 2001 prices, we would have incurred a gain of $1.0 million.

Subsequent to December 31, 2000, we entered into the following natural gas collar transactions designed to hedge a portion of our domestic gas production for periods after December 2000:

Months	Volume (mmbtu)	NYMEX Defined High Strike Price (per mmbtu)	NYMEX Defined Low Strike Price (per mmbtu)
June 2001	600,000	$6.80	$5.00
July 2001	620,000	6.80	5.00
August 2001	620,000	6.80	5.00
September 2001	600,000	6.80	5.00
January 2002	620,000	5.75	4.00
February 2002	560,000	5.75	4.00
March 2002	620,000	5.75	4.00
April 2002	1,200,000	5.38	4.00
May 2002	1,240,000	5.38	4.00
June 2002	1,200,000	5.38	4.00
July 2002	1,240,000	5.38	4.00
August 2002	1,240,000	5.38	4.00
September 2002	1,200,000	5.38	4.00
October 2002	1,240,000	5.38	4.00
November 2002	600,000	5.75	4.00
December 2002	620,000	5.75	4.00

Subsequent to December 31, 2000, we entered into the following natural gas cap-swaps designed to hedge a portion of our domestic gas production for periods after December 2000. This transaction requires that we pay the counterparty if the NYMEX price exceeds an average NYMEX-defined strike price. If the NYMEX price is less than the strike price, the counterparty pays us. However, the counterparty's payment is capped.

Months	Volume (mmbtu)	NYMEX Index Strike Price (per mmbtu)	Capped Low Strike Price (per mmbtu)
May 2001	1,860,000	5.77	4.60
June 2001	1,800,000	5.81	4.64
July 2001	1,860,000	5.85	4.68
August 2001	1,860,000	5.87	4.70
September 2001	1,800,000	5.83	4.66
October 2001	1,860,000	5.83	4.66
November 2001	2,400,000	6.00	4.78
December 2001	2,480,000	6.10	4.88
January 2002	2,790,000	6.03	4.83
February 2002	2,520,000	5.82	4.62
March 2002	2,790,000	5.48	4.28
April 2002	5,700,000	4.85	3.85
May 2002	5,890,000	4.81	3.81
June 2002	5,700,000	4.80	3.80
July 2002	5,890,000	4.81	3.81
August 2002	5,890,000	4.81	3.81
September 2002	5,700,000	4.81	3.81
October 2002	5,890,000	4.80	3.80
November 2002	2,100,000	4.97	3.97
December 2002	2,170,000	5.06	4.06

In addition to commodity hedging transactions related to our oil and gas production, our marketing subsidiary, CEMI, periodically enters into various hedging transactions designed to hedge against physical purchase and sale commitments it makes. Gains or losses on these transactions are recorded as adjustments to oil and gas marketing sales in the consolidated statements of operations and are not considered material by management.

Interest Rate Risk

Chesapeake also utilizes hedging strategies to manage fixed-interest rate exposure. Through the use of a swap arrangement, we reduced our interest expense by $2.6 million from May 1998 through December 2000.

During 2000, our interest rate swap resulted in a net $38,000 increase in interest expense. The terms of the swap agreement are as follows:

Months	Notional Amount	Fixed Rate	Floating Rate
May 1998 — April 2001	$230,000,000	7%	Average of three-month Swiss Franc LIBOR, Deutsche Mark and Australian Dollar plus 300 basis points
May 2001 — April 2008	$230,000,000	7%	U.S. three-month LIBOR plus 300 basis points

If the floating rate is less than the fixed rate, the counterparty will pay us accordingly. If the floating rate exceeds the fixed rate, we will pay the counterparty. The interest rate swap agreement contains a "knockout provision" whereby the agreement will terminate on or after May 1, 2001 if the average closing price for the previous twenty business days for shares of Chesapeake's common stock is greater than or equal to $7.50 per share. The agreement also provides for a maximum floating rate of 8.5% from May 2001 through April 2008.

Based on current market prices for Chesapeake common stock, we expect the interest rate swap agreement will terminate in May 2001 under the knockout provision of the agreement discussed above. The fair value of the swap agreement at December 31, 2000 was not material. Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the swap agreement.

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

	December 31, 2000							
	Years of Maturity							
	2001	2002	2003	2004	2005	Thereafter	Total	Fair Value
	($ in millions)							
Liabilities:								
Long-term debt, including current portion — fixed rate	$0.8	$ 0.6	$—	$150.0	$500.0	$270.0	$921.4	$894.7
Average interest rate	9.1%	9.1%	—	7.9%	9.6%	8.8%	9.1%	—
Long-term debt — variable rate	$ —	$25.0	$—	$ —	$ —	$ —	$ 25.0	$ 25.0
Average interest rate	—	9.3%	—	—	—	—	9.3%	—

ITEM 8. *Financial Statements and Supplementary Data*

INDEX TO FINANCIAL STATEMENTS

CHESAPEAKE ENERGY CORPORATION

GOTHIC 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 present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries (the "Company") at December 31, 1999 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule 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.

PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
March 28, 2001

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 1999	December 31, 2000
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 38,658	$ —
Restricted cash	192	3,500
Accounts receivable:		
Oil and gas sales	17,045	50,109
Oil and gas marketing sales	18,199	46,953
Joint interest and other, net of allowances of $3,218,000 and $1,085,000, respectively	11,247	15,998
Related parties	4,574	4,383
Deferred income tax asset	—	40,819
Inventory	4,582	3,167
Other	3,049	1,997
Total Current Assets	97,546	166,926
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	2,315,348	2,590,512
Unevaluated properties	40,008	25,685
Less: accumulated depreciation, depletion and amortization	(1,670,542)	(1,770,827)
	684,814	845,370
Other property and equipment	67,712	79,898
Less: accumulated depreciation and amortization	(33,429)	(37,034)
Total Property and Equipment	719,097	888,234
INVESTMENT IN GOTHIC ENERGY CORPORATION	10,000	126,434
DEFERRED INCOME TAX ASSET	—	229,823
OTHER ASSETS	23,890	29,009
TOTAL ASSETS	$ 850,533	$ 1,440,426
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
CURRENT LIABILITIES:		
Notes payable and current maturities of long-term debt	$ 763	$ 836
Accounts payable	24,822	62,940
Accrued property acquisitions	—	22,530
Accrued interest	17,807	17,537
Other accrued liabilities	16,906	21,637
Revenues and royalties due others	27,888	35,682
Income tax payable	—	1,539
Total Current Liabilities	88,186	162,701
LONG-TERM DEBT, NET	964,097	944,845
REVENUES AND ROYALTIES DUE OTHERS	9,310	7,798
DEFERRED INCOME TAX LIABILITY	6,484	11,850
CONTINGENCIES AND COMMITMENTS (Note 4)		
STOCKHOLDERS' EQUITY (DEFICIT):		
Preferred Stock, $.01 par value, 10,000,000 shares authorized; 4,596,400 and 624,037 shares of 7% cumulative convertible stock issued and outstanding at December 31, 1999 and 2000, respectively, entitled in liquidation to $229.8 million and $31.2 million, respectively	229,820	31,202
Common Stock, par value of $.01, 250,000,000 shares authorized; 105,858,580 and 157,819,171 shares issued at December 31, 1999 and 2000, respectively	1,059	1,578
Paid-in capital	682,905	963,584
Accumulated deficit	(1,093,929)	(659,286)
Accumulated other comprehensive income (loss)	196	(3,901)
Less: treasury stock, at cost; 10,856,185 and 4,788,747 common shares at December 31, 1999 and 2000, respectively	(37,595)	(19,945)
Total Stockholders' Equity (Deficit)	(217,544)	313,232
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 850,533	$ 1,440,426

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,		
	1998	1999	2000
	($ in thousands, except per share data)		
REVENUES:			
Oil and gas sales	$ 256,887	$280,445	$ 470,170
Oil and gas marketing sales	121,059	74,501	157,782
Total Revenues	377,946	354,946	627,952
OPERATING COSTS:			
Production expenses	51,202	46,298	50,085
Production taxes	8,295	13,264	24,840
General and administrative	19,918	13,477	13,177
Oil and gas marketing expenses	119,008	71,533	152,309
Oil and gas depreciation, depletion and amortization	146,644	95,044	101,291
Depreciation and amortization of other assets	8,076	7,810	7,481
Impairment of oil and gas properties	826,000	—	—
Impairment of other assets	55,000	—	—
Total Operating Costs	1,234,143	247,426	349,183
INCOME (LOSS) FROM OPERATIONS	(856,197)	107,520	278,769
OTHER INCOME (EXPENSE):			
Interest and other income	3,926	8,562	3,649
Interest expense	(68,249)	(81,052)	(86,256)
	(64,323)	(72,490)	(82,607)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	(920,520)	35,030	196,162
PROVISION (BENEFIT) FOR INCOME TAXES	—	1,764	(259,408)
INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(920,520)	33,266	455,570
EXTRAORDINARY ITEM:			
Loss on early extinguishment of debt, net of applicable income tax of $0	(13,334)	—	—
NET INCOME (LOSS)	(933,854)	33,266	455,570
PREFERRED STOCK DIVIDENDS	(12,077)	(16,711)	(8,484)
GAIN ON REDEMPTION OF PREFERRED STOCK	—	—	6,574
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$(945,931)	$ 16,555	$ 453,660
EARNINGS (LOSS) PER COMMON SHARE:			
EARNINGS (LOSS) PER COMMON SHARE — BASIC:			
Income (loss) before extraordinary item	$ (9.83)	$ 0.17	$ 3.52
Extraordinary item	(0.14)	—	—
Net income (loss)	$ (9.97)	$ 0.17	$ 3.52
EARNINGS (LOSS) PER COMMON SHARE-ASSUMING DILUTION:			
Income (loss) before extraordinary item	$ (9.83)	$ 0.16	$ 3.01
Extraordinary item	(0.14)	—	—
Net income (loss)	$ (9.97)	$ 0.16	$ 3.01
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):			
Basic	94,911	97,077	128,993
Assuming dilution	94,911	102,038	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,		
	1998	1999	2000
	($ in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$(933,854)	$ 33,266	$ 455,570
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	152,204	99,516	105,103
Provision (benefit) for deferred income taxes	—	1,764	(259,408)
Impairment of oil and gas assets	826,000	—	—
Impairment of other assets	55,000	—	—
Amortization of loan costs	2,516	3,338	3,669
Amortization of bond discount	98	84	84
Bad debt expense	1,589	9	256
Gain (loss) on sale of fixed assets	(90)	(459)	8
Extraordinary loss	13,334	—	—
Equity in (earnings) losses from investments	703	1,209	131
Other	—	—	391
Cash provided by operating activities before changes in current assets and liabilities	117,500	138,727	305,804
CHANGES IN ASSETS AND LIABILITIES:			
(Increase) decrease in short-term investments	12,027	—	—
(Increase) decrease in accounts receivable	12,191	17,592	(66,706)
(Increase) decrease in inventory	168	743	1,415
(Increase) decrease in other current assets	7,637	3,614	2,884
Increase (decrease) in accounts payable, accrued liabilities and other	(46,785)	(23,891)	64,955
Increase (decrease) in current and non-current revenues and royalties due others	(8,099)	3,517	6,282
Increase (decrease) in deferred income taxes	—	4,720	6
Changes in assets and liabilities	(22,861)	6,295	8,836
Cash provided by operating activities	94,639	145,022	314,640
CASH FLOWS FROM INVESTING ACTIVITIES:			
Exploration and development of oil and gas properties	(259,710)	(153,268)	(188,778)
Acquisitions of oil and gas companies, proved properties and unproved properties, net of cash acquired	(279,924)	(49,893)	(78,910)
Divestitures of oil and gas properties	15,712	45,635	1,529
Investment in preferred stock of Gothic Energy Corporation	(39,500)	—	—
Investment in Gothic (notes and other costs)	—	—	(36,693)
Repayment of note receivable	2,000	—	—
Proceeds from sale of investment in PanEast	21,245	—	—
Other proceeds from sales	3,600	5,530	1,069
Increase in deferred charges	—	(5,865)	(4,807)
Other investments	—	(730)	(10,019)
Other property and equipment additions	(11,473)	(1,182)	(13,427)
Cash used in investing activities	(548,050)	(159,773)	(330,036)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	658,750	116,500	244,000
Payments on long-term borrowings	(474,166)	(98,000)	(262,500)
Dividends paid on common stock	(5,592)	—	—
Dividends paid on preferred stock	(8,050)	—	(4,645)
Proceeds from issuance of preferred stock	222,663	—	—
Purchase of treasury stock and preferred stock	(29,962)	(53)	—
Cash paid in connection with issuance of common stock for preferred stock	—	—	(8,269)
Cash received from previous Gothic noteholders in settlement of make-whole provision	—	—	7,083
Cash received from exercise of stock options	154	520	1,398
Cash provided by (used in) financing activities	363,797	18,967	(22,933)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(4,726)	4,922	(329)
Net increase (decrease) in cash and cash equivalents	(94,340)	9,138	(38,658)
Cash and cash equivalents, beginning of period	123,860	29,520	38,658
Cash and cash equivalents, end of period	$ 29,520	$ 38,658	$ —

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,		
	1998	1999	2000
	($ in thousands)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$ 59,881	$80,684	$85,401
Income taxes	$ —	$ —	$ —
DETAILS OF ACQUISITION OF DLB OIL & GAS, INC.:			
Fair value of assets acquired	$ 136,500	$ —	$ —
Cash consideration	$ (17,500)	$ —	$ —
Stock issued (5,000,000 shares)	$ (30,000)	$ —	$ —
Debt assumed	$ (85,000)	$ —	$ —
Acquisition costs paid	$ (4,000)	$ —	$ —
DETAILS OF ACQUISITION OF HUGOTON ENERGY CORPORATION:			
Fair value of assets acquired	$ 343,371	$ —	$ —
Stock options granted	$ (2,050)	$ —	$ —
Stock issued (25,790,146 shares)	$(206,321)	$ —	$ —
Debt assumed	$(120,000)	$ —	$ —
Acquisition costs paid	$ (15,000)	$ —	$ —

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

In December 1997, we declared a dividend of $0.02 per common share, or $1,486,000, which was paid in January 1998.

Proceeds from the issuance of $500 million of 9.625% senior notes in April 1998 are net of $11.7 million in offering fees and expenses which were deducted from the actual cash received.

In 1999, the chief executive officer and chief operating officer of Chesapeake tendered to Chesapeake Energy Marketing, Inc. 2,320,107 shares of Chesapeake common stock in full satisfaction of two notes payable to CEMI with a combined outstanding balance of $7.6 million.

During 1999, we issued a $2.2 million note payable as consideration for the acquisition of certain oil and gas properties.

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 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 (DEFICIT) AND COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	1998	1999	2000
		($ in thousands)	
PREFERRED STOCK:			
Balance, beginning of period	$ —	$ 230,000	$ 229,820
Exchange of common stock and cash for 3,972,363 shares of preferred stock	—	—	(198,618)
Exchange of common stock for 3,600 shares of preferred stock	—	(180)	—
Issuance of preferred stock	230,000	—	—
Balance, end of period	230,000	229,820	31,202
COMMON STOCK:			
Balance, beginning of period	743	1,052	1,059
Exercise of stock options and warrants	—	6	20
Issuance of 25,790,146 shares of common stock to Hugoton Energy Corporation	258	—	—
Issuance of 5,000,000 shares of common stock to DLB Oil and Gas, Inc.	50	—	—
Exchange of 36,366,915 shares of common stock for preferred stock	—	—	363
Issuance of 13,553,302 shares of common stock to acquire Gothic notes	—	—	136
Change in par value and other	1	1	—
Balance, end of period	1,052	1,059	1,578
PAID-IN CAPITAL:			
Balance, beginning of period	460,770	682,263	682,905
Exercise of stock options and warrants	153	514	1,377
Issuance of common stock to acquire Gothic notes	—	—	93,885
Issuance of common stock to acquire Hugoton Energy Corporation	206,063	—	—
Issuance of common stock to acquire DLB Oil and Gas, Inc.	29,950	—	—
Offering expenses and other	(16,723)	1	—
Stock options issued in Hugoton purchase	2,050	—	—
Exchange of 36,366,915 shares of common stock for preferred stock	—	127	187,069
Exchange of 7,050,000 shares of treasury stock for preferred stock	—	—	(5,640)
Compensation related to stock options	—	—	238
Tax benefit from exercise of stock options	—	—	3,750
Balance, end of period	682,263	682,905	963,584
ACCUMULATED DEFICIT:			
Balance, beginning of period	(181,270)	(1,127,195)	(1,093,929)
Net income (loss)	(933,854)	33,266	455,570
Dividends on common stock	(4,021)	—	—
Dividends on preferred stock	(8,050)	—	(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	(1,127,195)	(1,093,929)	(659,286)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(37)	(4,726)	196
Foreign currency translation adjustments	(4,689)	4,922	(4,097)
Balance, end of period	(4,726)	196	(3,901)
TREASURY STOCK — COMMON:			
Balance, beginning of period	—	(29,962)	(37,595)
Settlement of notes receivable for 2,320,107 shares of common stock from related parties	—	(7,633)	—
Purchase of 8,503,300 shares of treasury stock	(29,962)	—	—
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	(29,962)	(37,595)	(19,945)
TOTAL STOCKHOLDERS' EQUITY (DEFICIT)	$ (248,568)	$ (217,544)	$ 313,232
COMPREHENSIVE INCOME (LOSS):			
Net income (loss)	$ (933,854)	$ 33,266	$ 455,570
Other comprehensive income (loss) — foreign currency translation adjustments	(4,689)	4,922	(4,097)
Comprehensive income (loss)	$ (938,543)	$ 38,188	$ 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. Our properties are located in Oklahoma, Texas, Arkansas, Louisiana, Kansas, Montana, Colorado, North Dakota, New Mexico and British Columbia and Saskatchewan, Canada.

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 debt instruments with maturities of three months or less at date of purchase to be cash equivalents.

Inventory

Inventory 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, 2000, approximately 72% 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 $1.13 ($1.17 in U.S. and $0.43 in Canada) per equivalent mcf in 1998, $0.71 ($0.73 in U.S. and $0.52 in Canada) per equivalent mcf in 1999, and $0.75 ($0.76 in U.S. and $0.71 in Canada) per equivalent mcf in 2000.

Proceeds from the sale of properties are accounted for as reductions to 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 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. During 1998, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in writedowns in the carrying value of oil and gas properties of $826 million.

Other Property and Equipment

Other property and equipment consists primarily of gas gathering and processing facilities, 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 both straight-line and accelerated methods. Buildings are depreciated on a straight-line basis over 31.5 years. All other property and equipment are depreciated over the estimated useful lives of the assets, which range from five to seven years.

Capitalized Interest

During 1998, 1999 and 2000, interest of approximately $6.5 million, $3.5 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.

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. For 1998, there was no difference between actual weighted average shares outstanding, which are used in computing basic EPS and diluted weighted average shares, which are used in computing diluted EPS.

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

- For the year ended December 31, 1999 and 2000, outstanding options to purchase 1.3 million and 1.1 million shares of common stock at a weighted average exercise price of $7.14 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, 1999, the assumed conversion of the outstanding preferred stock (convertible into 33 million common shares) was not included as the effect was antidilutive.

A reconciliation for the year ended December 31, 1999 and 2000 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Year Ended December 31, 1999:			
Basic EPS			
Income available to common stockholders	$16,555	97,077	$0.17
Effect of Dilutive Securities			
Employee stock options	—	4,961	
Diluted EPS			
Income available to common stockholders and assumed conversions	$16,555	102,038	$0.16
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 preferred stock at beginning of period	—	4,489	
Employee stock options	—	6,642	
Diluted EPS			
Income available to common stockholders and assumed conversions	$455,570	151,564	$3.01

During the year ended December 31, 2000, Chesapeake engaged in a number of unsolicited stock exchange 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 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 cancelled and retired and have 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 a net imbalance in excess of the remaining gas reserves on the underlying properties. Our net imbalance positions at December 31, 1998, 1999 and 2000 were not material.

Hedging

Chesapeake periodically uses commodity price risk management instruments to hedge our exposure to price fluctuations on 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, in oil and gas marketing sales to the extent related to our marketing activities, and in interest expense to the extent so related.

On June 15, 1998, the Financial Accounting Standards Board issued SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* SFAS 133 establishes a new model for accounting for derivatives and hedging activities and supersedes and amends a number of existing standards. SFAS 133 (as amended by SFAS 137 and SFAS 138) is effective for all fiscal quarters of fiscal years beginning after June 15, 2000.

SFAS 133 standardizes the accounting for derivative instruments by requiring that all derivatives be recognized as assets and liabilities and measured at fair value. The accounting for changes in the fair value of derivatives (gains and losses) depends on (i) whether the derivative is designated and qualifies as a hedge, and (ii) the type of hedging relationship that exists. Changes in the fair value of derivatives that are not designated as hedges or that do not meet the hedge accounting criteria in SFAS 133 are required to be reported in earnings. In addition, all hedging relationships must be designated, reassessed and documented pursuant to the provisions of SFAS 133. We will fully adopt SFAS 133 on January 1, 2001, the effective date as amended by SFAS 138. SFAS 133 is expected to increase volatility of stockholders' equity, reported earnings (losses) and other comprehensive income. If we had adopted SFAS 133 on December 31, 2000, Chesapeake would have recorded an additional $9.3 million in current assets and $98.6 million in current liabilities related to our existing oil and gas hedges based on the forward price curve in effect at December 31, 2000. The net liability of $89.3 million related to qualifying hedge instruments would have been charged to other comprehensive income which appears in the equity section of the balance sheet. After adoption, Chesapeake will be required to recognize any hedge ineffectiveness in the income statement each period.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes. The remaining unamortized costs on these issuances of senior notes at December 31, 1999 and 2000 totaled $16.6 million and $13.9 million, respectively, and are being amortized over the life of the senior notes.

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.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 1998 and 1999 to conform to the presentation used for the 2000 consolidated financial statements.

2. Senior Notes

On April 22, 1998, we issued $500 million principal amount of 9.625% Senior Notes due 2005. The 9.625% Senior Notes are redeemable at our option at any time on or after May 1, 2002 at the redemption prices set forth in the indenture or at the make-whole prices, as set forth in the indenture, if redeemed prior to May 1, 2002. We may also redeem at our option up to $167 million of the 9.625% Senior Notes at 109.625% of their principal amount with the proceeds of an equity offering completed prior to May 1, 2001.

On March 17, 1997, we issued $150 million principal amount of 7.875% Senior Notes due 2004. The 7.875% Senior Notes are redeemable at our option at any time prior to March 15, 2004, at the make-whole prices determined in accordance with the indenture.

Also on March 17, 1997, we issued $150 million principal amount of 8.5% Senior Notes due 2012. The 8.5% Senior Notes are redeemable at our option at any time prior to March 15, 2004, at the make-whole prices determined in accordance with the indenture and, on or after March 15, 2004, at the redemption prices set forth in the indenture. As of March 28, 2001, Chesapeake has purchased and subsequently retired $7.3 million of these notes for total consideration of $7.4 million, including accrued interest of $0.2 million.

On April 9, 1996, we issued $120 million principal amount of 9.125% Senior Notes due 2006. The 9.125% Senior Notes are redeemable at our option at any time prior to April 15, 2001 at the make-whole prices determined in accordance with the indenture and, on or after April 15, 2001, at the redemption prices set forth in the indenture.

On May 25, 1995, we issued $90 million principal amount of 10.5% Senior Notes due 2002. In April 1998, we purchased all of our 10.5% Senior Notes for approximately $99 million. The early retirement of these notes resulted in an extraordinary charge of $13.3 million.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under the 9.625% Senior Notes, the 9.125% Senior Notes, the 7.875% Senior Notes and the 8.5% 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 the Senior Notes). Each guarantor subsidiary is a direct or indirect wholly-owned subsidiary.

The senior note indentures contain certain covenants, including covenants limiting us and the guarantor subsidiaries with respect to asset sales; restricted payments; the incurrence of additional indebtedness and the issuance of preferred stock; liens; sale and leaseback transactions; lines of business; dividend and other payment restrictions affecting guarantor subsidiaries; mergers or consolidations; and transactions with affiliates. We are obligated to repurchase the 9.625% and 9.125% Senior Notes in the event of a change of control or certain asset sales.

The senior note indentures also limit our ability to make restricted payments (as defined), including the payment of cash dividends, unless certain tests are met. From December 31, 1998 through March 31, 2000, we were unable to meet the requirements to incur additional unsecured indebtedness, and consequently were restricted from paying cash dividends on our 7% cumulative convertible preferred stock. As a result of our failure to pay dividends for six quarterly periods, the holders of preferred stock were entitled to elect two new directors to the Chesapeake board after May 1, 2000. On September 22, 2000, we declared a regular quarterly dividend and a special dividend equal to all unpaid dividends on our preferred stock, both payable November 1, 2000 to shareholders of record on October 16, 2000. A total combined dividend of $7.444 per outstanding preferred share was paid November 1, 2000, eliminating the right of preferred stockholders to elect directors.

Set forth below are condensed consolidating financial statements of the guarantor subsidiaries and Chesapeake's subsidiaries which are not guarantors of the Senior Notes. Chesapeake Energy Marketing, Inc. was a non-guarantor subsidiary for all periods presented. All of our other subsidiaries were guarantor subsidiaries during all periods presented.

CONDENSED CONSOLIDATING BALANCE SHEET
As of December 31, 1999
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (7,156)	$ 20,409	$ 25,405	$ —	$ 38,658
Restricted cash	192	—	—	—	192
Accounts receivable	45,170	18,297	73	(12,475)	51,065
Inventory	4,183	399	—	—	4,582
Other	1,997	700	352	—	3,049
Total Current Assets	44,386	39,805	25,830	(12,475)	97,546
PROPERTY AND EQUIPMENT:					
Oil and gas properties	2,311,633	3,715	—	—	2,315,348
Unevaluated leasehold	40,008	—	—	—	40,008
Other property and equipment	29,088	20,521	18,103	—	67,712
Less: accumulated depreciation, depletion and amortization	(1,683,890)	(18,205)	(1,876)	—	(1,703,971)
Net Property and Equipment	696,839	6,031	16,227	—	719,097
INVESTMENTS IN SUBSIDIARIES AND INTERCOMPANY ADVANCES	—	—	(686,097)	686,097	—
INVESTMENT IN GOTHIC ENERGY CORPORATION	10,000	—	—	—	10,000
OTHER ASSETS	6,402	8,409	16,765	(7,686)	23,890
TOTAL ASSETS	$ 757,627	$ 54,245	$ (627,275)	$665,936	$ 850,533
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ —	$ 763	$ —	$ —	$ 763
Accounts payable and other	63,194	19,265	17,466	(12,502)	87,423
Total Current Liabilities	63,194	20,028	17,466	(12,502)	88,186
LONG-TERM DEBT	43,500	1,437	919,160	—	964,097
REVENUES AND ROYALTIES DUE OTHERS	9,310	—	—	—	9,310
DEFERRED INCOME TAX LIABILITY	6,484	—	—	—	6,484
INTERCOMPANY PAYABLES	1,356,466	(2,450)	(1,354,043)	27	—
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	27	1	1,048	(17)	1,059
Other	(721,354)	35,229	(210,906)	678,428	(218,603)
	(721,327)	35,230	(209,858)	678,411	(217,544)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 757,627	$ 54,245	$ (627,275)	$665,936	$ 850,533

CONDENSED CONSOLIDATING BALANCE SHEET
As of December 31, 2000
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (19,868)	$ 7,200	$ 12,668	$ —	$ —
Restricted cash	3,500	—	—	—	3,500
Accounts receivable	91,903	46,903	—	(21,363)	117,443
Deferred income tax asset	—	—	40,819	—	40,819
Inventory	3,040	127	—	—	3,167
Other	1,997	—	—	—	1,997
Total Current Assets	80,572	54,230	53,487	(21,363)	166,926
PROPERTY AND EQUIPMENT:					
Oil and gas properties	2,590,512	—	—	—	2,590,512
Unevaluated leasehold	25,685	—	—	—	25,685
Other property and equipment	30,670	23,246	25,982	—	79,898
Less: accumulated depreciation, depletion and amortization	(1,787,314)	(18,153)	(2,394)	—	(1,807,861)
Net Property and Equipment	859,553	5,093	23,588	—	888,234
INVESTMENTS IN SUBSIDIARIES AND INTERCOMPANY ADVANCES	—	—	(612,832)	612,832	—
INVESTMENT IN GOTHIC ENERGY CORPORATION	—	9,732	116,702	—	126,434
DEFERRED TAX ASSET	—	—	229,823	—	229,823
OTHER ASSETS	9,890	418	89,516	(70,815)	29,009
TOTAL ASSETS	$ 950,015	$ 69,473	$ (99,716)	$520,654	$ 1,440,426
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 836	$ —	$ —	$ —	$ 836
Accounts payable and other	118,620	49,613	19,090	(25,458)	161,865
Total Current Liabilities	119,456	49,613	19,090	(25,458)	162,701
LONG-TERM DEBT	92,321	—	919,244	(66,720)	944,845
REVENUES AND ROYALTIES DUE OTHERS	7,798	—	—	—	7,798
DEFERRED INCOME TAX LIABILITY	11,850	—	—	—	11,850
INTERCOMPANY PAYABLES	1,351,144	138	(1,351,282)	—	—
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	26	1	1,569	(18)	1,578
Other	(632,580)	19,721	311,663	612,850	311,654
	(632,554)	19,722	313,232	612,832	313,232
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 950,015	$ 69,473	$ (99,716)	$520,654	$ 1,440,426

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Year Ended December 31, 1998:					
REVENUES:					
Oil and gas sales	$ 256,887	$ —	$ —	$ —	$ 256,887
Oil and gas marketing sales	—	222,849	—	(101,790)	121,059
Total Revenues	256,887	222,849	—	(101,790)	377,946
OPERATING COSTS:					
Production expenses and taxes	59,497	—	—	—	59,497
General and administrative	18,081	1,766	71	—	19,918
Oil and gas marketing expenses	—	220,798	—	(101,790)	119,008
Impairment of oil and gas properties	826,000	—	—	—	826,000
Impairment of other assets	47,000	8,000	—	—	55,000
Oil and gas depreciation, depletion and amortization	146,644	—	—	—	146,644
Other depreciation and amortization	5,204	126	2,746	—	8,076
Total Operating Costs	1,102,426	230,690	2,817	(101,790)	1,234,143
INCOME (LOSS) FROM OPERATIONS	(845,539)	(7,841)	(2,817)	—	(856,197)
OTHER INCOME (EXPENSE):					
Interest and other income	649	2,259	100,886	(99,868)	3,926
Interest expense	(96,214)	(382)	(71,521)	99,868	(68,249)
Equity in net earnings of subsidiaries	—	—	(949,232)	949,232	—
	(95,565)	1,877	(919,867)	949,232	(64,323)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	(941,104)	(5,964)	(922,684)	949,232	(920,520)
INCOME TAX EXPENSE (BENEFIT)	—	—	—	—	—
NET INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(941,104)	(5,964)	(922,684)	949,232	(920,520)
EXTRAORDINARY ITEM:					
Loss on early extinguishment of debt, net of applicable income tax	(2,164)	—	(11,170)	—	(13,334)
NET INCOME (LOSS)	$ (943,268)	$ (5,964)	$(933,854)	$ 949,232	$ (933,854)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Year Ended December 31, 1999:					
REVENUES:					
Oil and gas sales	$280,445	$ —	$ —	$ —	$280,445
Oil and gas marketing sales	—	193,900	—	(119,399)	74,501
Total Revenues	280,445	193,900	—	(119,399)	354,946
OPERATING COSTS:					
Production expenses and taxes	59,158	404	—	—	59,562
General and administrative	12,143	1,251	83	—	13,477
Oil and gas marketing expenses	—	190,932	—	(119,399)	71,533
Oil and gas depreciation, depletion and amortization	94,649	395	—	—	95,044
Other depreciation and amortization	4,474	80	3,256	—	7,810
Total Operating Costs	170,424	193,062	3,339	(119,399)	247,426
INCOME (LOSS) FROM OPERATIONS	110,021	838	(3,339)	—	107,520
OTHER INCOME (EXPENSE):					
Interest and other income	3,257	4,823	84,120	(83,638)	8,562
Interest expense	(82,852)	(96)	(81,742)	83,638	(81,052)
Equity in net earnings of subsidiaries	—	—	34,227	(34,227)	—
	(79,595)	4,727	36,605	(34,227)	(72,490)
INCOME (LOSS) BEFORE INCOME TAXES	30,426	5,565	33,266	(34,227)	35,030
INCOME TAX EXPENSE (BENEFIT)	1,764	—	—	—	1,764
NET INCOME (LOSS)	$ 28,662	$ 5,565	$ 33,266	$ (34,227)	$ 33,266

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ in thousands)

	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 and taxes	74,845	80	—	—	74,925
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
Other depreciation and amortization	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 BEFORE INCOME TAXES	190,637	5,189	190,570	(190,234)	196,162
INCOME TAX EXPENSE (BENEFIT)	5,592	—	(265,000)	—	(259,408)
NET INCOME	$185,045	$ 5,189	$ 455,570	$(190,234)	$ 455,570

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Year Ended December 31, 1998:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 66,960	$(13,137)	$(908,416)	$ 949,232	$ 94,639
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties	(523,922)	—	—	—	(523,922)
Proceeds from sale of assets	—	—	3,600	—	3,600
Investment in preferred stock of Gothic Energy Corporation	(39,500)	—	—	—	(39,500)
Repayment of note receivable	2,000	—	—	—	2,000
Proceeds from sale of PanEast Petroleum Corporation	—	—	21,245	—	21,245
Other additions	(2,510)	8,408	(17,371)	—	(11,473)
	(563,932)	8,408	7,474	—	(548,050)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	—	—	658,750	—	658,750
Payments on long-term borrowings	—	—	(474,166)	—	(474,166)
Cash received from issuance of preferred stock	—	—	222,663	—	222,663
Cash paid for purchase of treasury stock	—	—	(29,962)	—	(29,962)
Dividends paid on common stock and preferred stock	—	—	(13,642)	—	(13,642)
Exercise of stock options	—	—	154	—	154
Intercompany advances, net	476,663	6,035	466,534	(949,232)	—
	476,663	6,035	830,331	(949,232)	363,797
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(4,726)	—	—	—	(4,726)
Net increase (decrease) in cash and cash equivalents	(25,035)	1,306	(70,611)	—	(94,340)
Cash, beginning of period	(284)	13,694	110,450	—	123,860
Cash, end of period	$ (25,319)	$ 15,000	$ 39,839	$ —	$ 29,520

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Year Ended December 31, 1999:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 135,303	$ 7,193	$ 36,753	$(34,227)	$ 145,022
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(159,888)	2,362	—	—	(157,526)
Proceeds from sale of assets	2,082	3,448	—	—	5,530
Other investments	(480)	(250)	—	—	(730)
Other additions	(5,777)	(72)	(1,198)	—	(7,047)
	(164,063)	5,488	(1,198)	—	(159,773)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	116,500	—	—	—	116,500
Payments on long-term borrowings	(98,000)	—	—	—	(98,000)
Cash paid for purchase of preferred stock	—	(53)	—	—	(53)
Exercise of stock options	—	—	520	—	520
Intercompany advances, net	15,501	781	(50,509)	34,227	—
	34,001	728	(49,989)	34,227	18,967
EFFECT OF EXCHANGE RATE CHANGES ON CASH	4,922	—	—	—	4,922
Net increase (decrease) in cash and cash equivalents	10,163	13,409	(14,434)	—	9,138
Cash, beginning of period	(17,319)	7,000	39,839	—	29,520
Cash, end of period	$ (7,156)	$ 20,409	$ 25,405	$ —	$ 38,658

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 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	(4,453)	(2,740)	(11,041)	—	(18,234)
	(279,364)	(34,285)	(16,387)	—	(330,036)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	244,000	—	—	—	244,000
Payments on long-term borrowings	(262,500)	—	—	—	(262,500)
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	—
	(53,021)	30,703	(190,849)	190,234	(22,933)
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, 1998:					
Net income (loss)	$(943,268)	$(5,964)	$(933,854)	$ 949,232	$(933,854)
Other comprehensive income (loss) — foreign currency translation	(4,689)	—	—	—	(4,689)
Comprehensive income (loss)	$(947,957)	$(5,964)	$(933,854)	$ 949,232	$(938,543)
For the Year Ended December 31, 1999:					
Net income (loss)	$ 28,662	$ 5,565	$ 33,266	$ (34,227)	$ 33,266
Other comprehensive income (loss) — foreign currency translation	4,922	—	—	—	4,922
Comprehensive income (loss)	$ 33,584	$ 5,565	$ 33,266	$ (34,227)	$ 38,188
For the Year Ended December 31, 2000:					
Net income	$ 185,045	$ 5,189	$ 455,570	$(190,234)	$ 455,570
Other comprehensive income (loss) — foreign currency translation	(4,097)	—	—	—	(4,097)
Comprehensive income	$ 180,948	$ 5,189	$ 455,570	$(190,234)	$ 451,473

3. Notes Payable and Long-Term Debt

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

	December 31, 1999	December 31, 2000
	($ in thousands)	
7.875% Senior Notes (see note 2)	$150,000	$150,000
Discount on 7.875% Senior notes	(73)	(55)
8.5% Senior Notes (see note 2)	150,000	150,000
Discount on 8.5% Senior notes	(715)	(657)
9.125% Senior Notes (see note 2)	120,000	120,000
Discount on 9.125% Senior notes	(52)	(44)
9.625% Senior Notes (see note 2)	500,000	500,000
Note payable	2,200	1,437
Revolving bank credit facility	43,500	25,000
Total notes payable and long-term debt	964,860	945,681
Less — current maturities	(763)	(836)
Notes payable and long-term debt, net of current maturities	$964,097	$944,845

Chesapeake has a $100 million revolving bank credit facility which matures in July 2002, with a committed borrowing base of $100 million. As of December 31, 2000, we had borrowed $25 million under the revolving bank credit facility and had $31.5 million of the facility securing various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at a variable rate, which was 9.3% per annum as of December 31, 2000. Interest is payable quarterly calculated at .50% to 1.25%, depending on utilization, plus the higher of (a) the Union Bank of California reference rate or (b) the federal funds rate plus .50% per year. We may elect to convert a portion of our borrowings to interest calculated under a London Interbank Offered Rate (LIBOR) plus 2.00% to 2.75%, depending on utilization. We are required to pay a commitment fee on the unused portion of the borrowing base equal to 0.375% per annum due quarterly.

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 existing revolving credit facility. The term loan was available to repurchase any of Gothic Production Corporation's 11.125% senior secured notes tendered following the closing of the Gothic acquisition 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 $3.2 million of costs for the standby facility.

The aggregate scheduled maturities of notes payable and long-term debt for the next five fiscal years ending December 31, 2005, and thereafter were as follows as of December 31, 2000 ($ in thousands):

2001	$ 836
2002	25,601
2003	—
2004	149,945
2005	500,000
After 2005	269,299
	$945,681

4. Contingencies and Commitments

West Panhandle Field Cessation Cases. One of our subsidiaries, Chesapeake Panhandle Limited Partnership ("CP") (f/k/a MC Panhandle, Inc.), and two subsidiaries of Kinder Morgan, Inc. have been defendants in 13 lawsuits filed between June 1997 and January 1999 by royalty owners seeking the cancellation of oil and gas leases in the West Panhandle Field in Texas. MC Panhandle, Inc., which we acquired in April 1998, has owned the leases since January 1, 1997. The co-defendants are prior lessees. The plaintiffs in these cases have claimed the leases terminated upon the cessation of production for various periods, primarily during the 1960s. In addition, the plaintiffs have sought to recover conversion damages, exemplary damages, attorneys' fees and interest. The defendants have asserted that any cessation of production was excused and have pled affirmative defenses of limitations, waiver, temporary estoppel, laches and title by adverse possession. Four of the 13 cases have been tried, and there have been appellate decisions in three of them. In January 2001, the principal plaintiffs in eight of ten cases tried or pending in the District Court of Moore County, Texas, 69th Judicial District agreed to settle their claims. We do not consider our portion of the settlement consideration material to our financial condition or results of operations.

There are five related West Panhandle cessation cases which continue to be pending, two in the District Court of Moore County, Texas, 69th Judicial District, one in the District Court of Carson County, Texas, 100th Judicial District, and two in the U.S. District Court, Northern District of Texas, Amarillo Division. In one of the Moore County cases, CP and the other defendants have appealed a January 2000 judgment notwithstanding verdict in favor of plaintiffs. In addition to quieting title to the lease (including existing gas wells and all attached equipment) in plaintiffs, the court awarded actual damages against CP in the amount of $716,400 and exemplary damages in the amount of $25,000. The court further awarded, jointly and severally from all defendants, $160,000 in attorneys' fees and interest and court costs. On March 28, 2001, the Amarillo Court of Appeals reversed and rendered the judgment in favor of CP and the other defendants, finding that the subject leases had been revived as a matter of law, making all other issues moot. In the other Moore County, Texas case, in June 1999, the court granted plaintiffs' motion for summary judgment in part, finding that the lease had terminated due to the cessation of production, subject to the defendants' affirmative defenses. In February 2001, the court granted plaintiffs' motion for summary judgment on defendants' affirmative defenses but reversed its ruling that the lease had terminated as a matter of law. In one of the U.S. District Court cases, after a trial in May 1999, the jury found plaintiffs' claims were barred by the payment of shut-in royalties, laches and revivor. Plaintiffs have moved for a new trial. There are motions pending in the remaining two cases and no trial date has been set.

We have previously established an accrued liability we believe will be sufficient to cover the estimated costs of litigation for each of the pending cases and the settlement consideration under the terms of the settlement agreement mentioned above. Because of the inconsistent verdicts reached by the juries in the four 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 the amount of damages that might ultimately be awarded could differ from management's estimates. CP and the other defendants intend to vigorously defend against the plaintiffs' claims.

Chesapeake is currently involved in various other routine disputes incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, 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 the consolidated financial position or results of operations of Chesapeake.

Chesapeake has employment contracts with its chief executive officer, chief operating officer and chief financial officer and various other senior management personnel which provide for annual base salaries, bonus compensation and various benefits. The contracts 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, 2000. 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.

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.

5. Income Taxes

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

	Years Ended December 31,		
	1998	1999	2000
	($ in thousands)		
Current	$ —	$ —	$ 1,800
Deferred:			
United States	—	—	(266,800)
Foreign	—	1,764	5,592
Total	$ —	$1,764	$(259,408)

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

	Years Ended December 31,		
	1998	1999	2000
	($ in thousands)		
Computed "expected" income tax provision (benefit)	$(322,182)	$12,720	$ 70,168
Tax percentage depletion	(430)	(240)	(191)
Change in valuation allowance	380,969	(10,956)	(329,516)
State income taxes and other	(58,357)	240	131
	$ —	$ 1,764	$(259,408)

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,	
	1999	2000
	($ in thousands)	
Deferred tax liabilities:		
Acquisition, exploration and development costs and related depreciation, depletion and amortization	$ (6,484)	$(11,850)
Deferred tax assets:		
Acquisition, exploration and development costs and related depreciation, depletion and amortization	211,961	50,567
Net operating loss carryforwards	228,279	216,332
Percentage depletion carryforward	1,776	1,851
Alternative minimum tax credits	—	1,892
Deferred tax asset	442,016	270,642
Net deferred tax asset (liability)	435,532	258,792
Less: Valuation allowance	(442,016)	—
Total deferred tax asset (liability)	$ (6,484)	$258,792
Reflected in accompanying balance sheets as:		
Current income tax asset	—	40,819
Deferred income tax asset	—	229,823
Deferred income tax liability	(6,484)	(11,850)
	$ (6,484)	$258,792

At December 31, 2000, we classified $41 million of our deferred tax assets as current to recognize the portion of the NOL carryover that is expected to be utilized to reduce taxable income in 2001.

During 2000, we revised our estimate of the 1999 U.S. net deferred tax asset from $442 million to $330 million as a result of further evaluation of the income tax basis of several acquisitions. Since there was a full valuation allowance against the deferred tax asset, this revision had no impact on net income.

In the fourth quarter of 2000, we eliminated our valuation allowance resulting in the recognition of a $265 million income tax benefit. This resulted in an increase to 2000 net income of $265 million, or $1.75 per diluted share. Based upon recent results of operations and anticipated improvement in Chesapeake's outlook for sustained profitability, we 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.

At December 31, 2000, Chesapeake had U.S. regular tax net operating loss carryforwards of approximately $567 million and a U.S. alternative minimum tax net operating loss carryforward of approximately $301 million. The U.S. loss carryforward amounts will expire during the years 2009 through 2019. We also had a U.S. percentage depletion carryforward of approximately $5 million at December 31, 2000, which is available to offset Chesapeake's future U.S. federal income and has no expiration date. A summary of our NOLs follows:

	NOL	AMT NOL
	($ in thousands)	
Expiration Date:		
December 31, 2009	$ 19,099	$ —
December 31, 2010	41,494	—
December 31, 2011	168,186	17,559
December 31, 2012	48,229	—
December 31, 2018	154,642	146,840
December 31, 2019	135,697	137,094
Total	$567,347	$301,493

In the event of an ownership change, Section 382 of the Internal Revenue 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. Of the $567 million NOLs and $301 million AMT NOLs, the utilization of $254 million and the utilization of $25 million, respectively, are subject to annual limitations under Section 382. Therefore, $313 million of NOLs and $276 million of the AMT NOLs are not subject to the limitation. The utilization of $254 million of the NOLs and $25 million of the AMT NOLs subject to the Section 382 limitation are both limited to approximately $26 million each taxable year.

6. Related Party Transactions

Certain directors, shareholders and employees of Chesapeake have acquired working interests in certain of our oil and gas properties. The owners of such working interests are required to pay their proportionate share of all costs. As of December 31, 1999 and 2000, we had accounts receivable from related parties, primarily related to such participation, of $4.6 million and $4.4 million, respectively.

As of December 31, 1998, the chief executive officer and chief operating officer of Chesapeake had notes payable to Chesapeake Energy Marketing, Inc. in the principal amount of $9.9 million. In November 1999, the chief executive officer and the chief operating officer tendered 2,320,107 shares of Chesapeake common stock in full satisfaction of the notes, which had a combined outstanding balance of $7.6 million. The common stock was valued at $3.29 per share, which was the market value of the stock at the time of the transaction.

During 1998, 1999 and 2000, we incurred legal expenses of $493,000, $398,000 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 10% of the employee's annual salary 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 $1,359,000, $1,163,000 and $1,490,000 to the plan during 1998, 1999 and 2000, respectively.

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,		Amount	Percent of Oil and Gas Sales
		($ in thousands)	
1998	Koch Oil Company	$30,564	12%
	Aquila Southwest Pipeline Corporation	$28,946	11%
1999	Aquila Southwest Pipeline Corporation	$31,505	11%
2000	Aquila Southwest Pipeline Corporation	$54,931	12%

Management believes that the loss of any of the above customers would not have a material impact on our results of operations or our financial position.

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)	
1998:			
Revenue	$ 369,968	$ 7,978	$ 377,946
Operating income (loss)	(842,798)	(13,399)	(856,197)
Long-lived assets	617,431	77,185	694,616
1999:			
Revenue	$ 340,969	$ 13,977	$ 354,946
Operating income (loss)	103,188	4,332	107,520
Long-lived assets	648,841	104,146	752,987
2000:			
Revenue	$ 594,126	$ 33,826	$ 627,952
Operating income (loss)	259,828	18,941	278,769
Long-lived assets	1,163,952	109,548	1,273,500

9. Stockholders' Equity and Stock-Based Compensation

During 1998, our Board of Directors approved the expenditure of up to $30 million to purchase our outstanding common stock. During 1998, we purchased 8.5 million shares of common stock for an aggregate amount of $30 million pursuant to such authorization.

On April 28, 1998, we acquired by merger the Mid-Continent operations of DLB Oil & Gas, Inc. for $17.5 million in cash, 5 million shares of our common stock, and the assumption of $90 million in outstanding debt and working capital obligations.

On April 22, 1998, we issued $230 million (4.6 million shares) of our 7% cumulative convertible preferred stock, $50 per share liquidation preference, resulting in net proceeds to us of $223 million.

On March 10, 1998, we acquired Hugoton Energy Corporation pursuant to a merger by issuing 25.8 million shares of our common stock in exchange for 100% of Hugoton's common stock.

In November 1999, the chief executive officer and the chief operating officer of Chesapeake tendered 2,320,107 shares of Chesapeake common stock in full satisfaction of two notes payable to Chesapeake Energy Marketing, Inc. with a combined outstanding balance of $7.6 million. See note 6.

During 2000, Chesapeake 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 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 Chesapeake 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 Chesapeake common stock (982,562 shares) from the sellers of Gothic notes pursuant to make-whole provisions included in the purchase agreements. These provisions required payments to be made by the sellers to us or additional payments to be made by us to the sellers, depending upon changes in market value of our common stock during a specified period pending registration of our common stock issued to the sellers of Gothic notes.

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 consisting 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 as described above. Through the make-whole provisions, Chesapeake received cash of $1.0 million.

Stock Option Plans

Chesapeake's 1992 Incentive Stock Option Plan terminated on December 16, 1994. Until then, we granted incentive stock options to purchase common stock under the ISO Plan to employees. Subject to any adjustment as provided by the ISO Plan, the aggregate number of shares which may be issued and sold may not exceed 3,762,000 shares. The maximum period for exercise of an option may not be more than ten years (or five years for an optionee who owns more than 10% of the common stock) 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 (or 110% of such value for an optionee who owns more than 10% of the common stock). Options granted become exercisable at dates determined by the Stock Option Committee of the Board of Directors.

Under our 1992 Nonstatutory Stock Option Plan, non-qualified options to purchase common stock may be granted only to directors and consultants of Chesapeake. Subject to any adjustment as provided by this plan, the aggregate number of shares which may be issued and sold may not exceed 3,132,000 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 director who is not an executive officer receives every quarter a ten-year immediately exercisable option to purchase 7,500 shares of common stock at an option price equal to the fair market value of the shares on the date of grant. The amount of the award was changed from 20,000 shares to 15,000 shares per year in 1998, to 25,000 shares per year in 1999 and to 30,000 shares per year in 2000. No options can be granted under this plan after December 10, 2002.

Under Chesapeake's 1994 Stock Option Plan, and our 1996 Stock Option Plan, incentive and nonqualified stock options to purchase Chesapeake 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 nonqualified stock options may not be less than par value and, under the 1996 Plan, 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.

Under Chesapeake's 1999 Stock Option Plan, nonqualified stock options to purchase Chesapeake common stock may be granted to employees and consultants of Chesapeake. Subject to any adjustment as provided by this plan, the aggregate number of shares which may be issued and sold may not exceed 3,000,000 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; 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 this plan after March 4, 2009.

Under Chesapeake's 2000 Employee Stock Option Plan, nonqualified stock options to purchase Chesapeake common stock may be granted to employees 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 3,000,000 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; 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 this plan after April 25, 2010.

Under Chesapeake's 2000 Executive Officer Stock Option Plan, nonqualified stock options to purchase Chesapeake 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 issued and sold may not exceed 2,500,000 shares 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 this plan after April 25, 2010.

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 $238,000 was recognized in 2000 as a result of modifications that were made during the year ended December 31, 2000. No compensation expense has been recognized for newly issued stock options in 1998, 1999 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 1998, 1999 and 2000, respectively: interest rates (zero-coupon U.S. government issues with a remaining life equal to the expected term of the options) of 5.20%, 5.88% and 6.32%; dividend yields of 0.0%, 0.0% and 0.0%; volatility factors of the expected market price of our common stock of .96, .82, and .73; and weighted-average expected life of the options of five years.

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 its employee stock options.

Chesapeake's pro forma information follows:

	Years Ended December 31, 1998	1999	2000
	($ in thousands, except per share amounts)		
Net Income (Loss)			
As reported	$(933,854)	$33,266	$455,570
Pro forma	(948,014)	24,802	444,865
Basic Earnings (Loss) per Share			
As reported	$ (9.97)	$ 0.17	$ 3.52
Pro forma	(10.12)	0.08	3.43
Diluted Earnings (Loss) per Share			
As reported	$ (9.97)	$ 0.16	$ 3.01
Pro forma	(10.12)	0.08	2.94

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

	Years Ended December 31, 1998		1999		2000	
	Options	Weighted-Avg Exercise Price	Options	Weighted-Avg Exercise Price	Options	Weighted-Avg Exercise Price
Outstanding Beginning of Period	8,330,381	$5.49	11,260,375	$1.86	12,858,429	$1.76
Granted	14,580,063	2.78	3,210,493	1.11	8,143,280	4.08
Exercised	(108,761)	1.35	(622,120)	0.99	(2,177,644)	1.21
Cancelled/Forfeited	(11,541,308)	5.64	(990,319)	1.87	(424,903)	2.47
Outstanding End of Period	11,260,375	$1.86	12,858,429	$1.76	18,399,162	$2.83
Exercisable End of Period	3,535,126	$2.99	5,040,302	$2.66	5,422,884	$2.61
Shares Authorized for Future Grants	1,761,359		2,560,687		588,435	
Fair Value of Options Granted During the Period		$2.34		$0.77		$2.63

The following table summarizes information about stock options outstanding at December 31, 2000:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding @ 12/31/00	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Number Exercisable @ 12/31/00	Weighted-Avg. Exercise Price
$0.08-$0.78	694,282	3.04	$0.63	694,282	$0.63
0.94-1.00	2,090,445	8.09	0.94	312,258	0.95
1.13-2.06	5,574,715	7.36	1.15	2,341,978	1.17
2.25-2.25	2,346,300	8.95	2.25	46,250	2.25
2.25-3.81	1,341,275	4.15	2.50	1,307,405	2.49
4.00-4.00	2,629,000	9.31	4.00	31,250	4.00
4.06-5.50	97,569	7.26	4.75	62,336	4.91
5.56-5.92	3,041,663	9.74	5.57	91,313	5.81
6.13-8.75	439,663	5.66	7.09	398,187	7.10
10.69-30.63	144,250	5.43	25.14	137,625	25.66
$0.08-$30.63	18,399,162	7.86	$2.83	5,422,884	$2.61

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 2000, we recognized a tax benefit of $3.8 million, which was recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits. There was no similar tax benefit in 1998 or 1999.

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

Chesapeake has only limited involvement with derivative financial instruments, as defined in Statement of Financial Accounting Standards No. 119 "Disclosure About Derivative Financial Instruments and Fair Value of Financial Instruments", and does not use them for trading purposes. Our primary objective is to hedge a portion of our exposure to price volatility from producing crude oil and natural gas. These arrangements may expose us to credit risk from our counterparties and to basis risk. We do not expect that the counterparties will fail to meet their obligations given their high credit ratings.

Hedging Activities

Periodically Chesapeake utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include:

- swap arrangements that establish an index-related price above which we pay the counterparty and below which we are paid by the counterparty (counterparty payments in some contracts are subject to a cap),
- the purchase of index-related puts that provide for a "floor" price below which the counterparty pays the amount by which the price of the commodity is below the contracted floor,
- the sale of index-related calls that provide for a "ceiling" price above which we pay the counterparty the amount by which the price of the commodity is above the contracted ceiling,
- basis protection swaps, which are arrangements that guarantee the price differential of oil or gas from a specified delivery point or points, and
- collar arrangements that establish an index-related price below which the counterparty pays us and a separate index-related price above which we pay the counterparty.

Commodity markets are volatile, and as a result, our hedging activity is dynamic. As market conditions warrant, we may elect to settle a hedging transaction prior to its scheduled maturity date and, as a result, realize a gain or loss on the transaction.

Results from commodity hedging transactions are reflected in oil and gas sales to the extent related to our oil and gas production. We only enter into commodity hedging transactions related to our oil and gas production volumes or physical purchase or sale commitments of our marketing subsidiary. Gains or losses on crude oil and natural gas hedging transactions are recognized as price adjustments in the months of related production.

As of December 31, 2000, we had the following open natural gas swap arrangements designed to hedge a portion of our domestic gas production for periods after December 2000:

Months	Volume (mmbtu)	NYMEX-Index Strike Price (per mmbtu)
January 2001	4,960,000	$6.03
February 2001	5,320,000	6.12
March 2001	4,650,000	5.11
April 2001	5,100,000	4.79
May 2001	5,270,000	4.63
June 2001	3,900,000	4.61
July 2001	4,030,000	4.59
August 2001	4,030,000	4.58
September 2001	3,900,000	4.57
October 2001	620,000	4.80

If the swap arrangements listed above had been settled on December 31, 2000, we would have incurred a loss of $80.1 million. Subsequent to December 31, 2000, we settled the natural gas swaps for January, February and March 2001. A loss of $18.6 million and $4.4 million and a gain of $0.1 million will be recognized as price adjustments in January, February and March, respectively. If we had settled the remaining swaps (April through October) using March 21, 2001 prices, we would have incurred a loss of $13.5 million.

On June 2, 2000, we entered into a natural gas basis protection swap transaction for 13,500,000 mmbtu for the period of January 2001 through March 2001. This transaction requires that the counterparty pay us if the NYMEX price exceeds the Houston Ship Channel Beaumont/Texas Index by more than $0.0675 for each of the related months of production. If the NYMEX price less $0.0675 does not exceed the Houston Ship Channel Beaumont/Texas Index for each month, we will pay the counterparty. Gains or losses on basis swap transactions are recognized as price adjustments in the month of related production. Subsequent to December 31, 2000, we settled the natural gas basis protection swaps for January, February and March 2001. A gain of $0.3 million, a loss of $0.1 million and a loss of $0.5 million will be recognized as price adjustments in January, February and March, respectively.

As of December 31, 2000, we had open natural gas collar transactions designed to hedge 60,000 mmbtu per day throughout 2001 at an average NYMEX-defined high strike price (cap) of $6.08 per mmbtu and an average NYMEX-defined low strike price (floor) of $4.00 per mmbtu. If the collar transactions had been settled on December 31, 2000, we would have incurred a loss of $18.5 million. Subsequent to December 31, 2000, we settled the natural gas collar transactions for January, February and March 2001. A loss of $6.9 million and $1.4 million will be recognized as price adjustments in January and February, respectively. The March 2001 contract was settled for no gain or loss.

As of December 31, 2000, we had the following open crude oil swap arrangements designed to hedge a portion of our domestic crude oil production for periods after December 2000:

Months	Volume (bbls)	NYMEX-Index Strike Price (per bbl)
January 2001	165,000	$29.97
February 2001	150,000	29.92
March 2001	165,000	29.84
April 2001	160,000	29.80
May 2001	165,000	29.75
June 2001	160,000	29.71
July 2001	165,000	29.68
August 2001	165,000	29.65
September 2001	160,000	29.62
October 2001	165,000	29.59
November 2001	160,000	29.56
December 2001	165,000	29.54

If the swap arrangements listed above had been settled on December 31, 2000, we would have realized a gain of $9.3 million. Subsequent to December 31, 2000, we settled the crude oil swap for January 2001 for a gain of $0.1 million and February for a gain of $41,350, which will be recognized as a price adjustment in January and February 2001.

Subsequent to December 31, 2000, we entered into the following natural gas swap arrangements designed to hedge a portion of our domestic gas production for periods after December 2000:

Months	Volume (mmbtu)	NYMEX-Index Strike Price (per mmbtu)
March 2001	310,000	$5.93
April 2001	300,000	5.66
May 2001	930,000	5.34
June 2001	900,000	5.37
July 2001	930,000	5.40
August 2001	930,000	5.42
September 2001	900,000	5.38
October 2001	1,240,000	5.40

The natural gas swap for March 2001 was settled for a gain of $0.3 million which will be recognized as a price adjustment in March 2001. If we had settled the remaining swaps (April through October) using March 21, 2001 prices, we would have realized a gain of $1.0 million.

Subsequent to December 31, 2000, we entered into the following natural gas collar transactions designed to hedge a portion of our domestic gas production for periods after December 2000:

Months	Volume (mmbtu)	NYMEX Defined High Strike Price (per mmbtu)	NYMEX Defined Low Strike Price (per mmbtu)
June 2001	600,000	$ 6.80	$ 5.00
July 2001	620,000	6.80	5.00
August 2001	620,000	6.80	5.00
September 2001	600,000	6.80	5.00
January 2002	620,000	5.75	4.00
February 2002	560,000	5.75	4.00
March 2002	620,000	5.75	4.00
April 2002	1,200,000	5.38	4.00
May 2002	1,240,000	5.38	4.00
June 2002	1,200,000	5.38	4.00
July 2002	1,240,000	5.38	4.00
August 2002	1,240,000	5.38	4.00
September 2002	1,200,000	5.38	4.00
October 2002	1,240,000	5.38	4.00
November 2002	600,000	5.75	4.00
December 2002	620,000	5.75	4.00

Subsequent to December 31, 2000, we entered into natural gas cap-swaps designed to hedge a portion of our domestic gas production for periods after December 2000. This transaction requires that we pay the counterparty if the NYMEX price exceeds an average NYMEX-defined strike price. If the NYMEX price is less than the strike price, the counterparty pays us. However, the counterparty's payment is capped.

Months	Volume (MMbtu)	NYMEX Index Strike Price (per MMbtu)	Capped Low Strike Price (per MMbtu)
May 2001	1,860,000	5.77	4.60
June 2001	1,800,000	5.81	4.64
July 2001	1,860,000	5.85	4.68
August 2001	1,860,000	5.87	4.70
September 2001	1,800,000	5.83	4.66
October 2001	1,860,000	5.83	4.66
November 2001	2,400,000	6.00	4.78
December 2001	2,480,000	6.10	4.88
January 2002	2,790,000	6.03	4.83
February 2002	2,520,000	5.82	4.62
March 2002	2,790,000	5.48	4.28
April 2002	5,700,000	4.85	3.85
May 2002	5,890,000	4.81	3.81
June 2002	5,700,000	4.80	3.80
July 2002	5,890,000	4.81	3.81
August 2002	5,890,000	4.81	3.81
September 2002	5,700,000	4.81	3.81
October 2002	5,890,000	4.80	3.80
November 2002	2,100,000	4.97	3.97
December 2002	2,170,000	5.06	4.06

In addition to commodity hedging transactions related to our oil and gas production, our marketing subsidiary, CEMI, periodically enters into various hedging transactions designed to hedge against physical purchase and sale commitments it makes. Gains or losses on these transactions are recorded as adjustments to oil and gas marketing sales in the consolidated statements of operations and are not considered by management to be material.

Interest Rate Risk

Chesapeake also utilizes hedging strategies to manage fixed-interest rate exposure. Through the use of a swap arrangement, we reduced our interest expense by $2.6 million from May 1998 through December 2000. During 2000, our interest rate swap resulted in a $38,000 increase in interest expense. The terms of the swap agreement are as follows:

Months	Notional Amount	Fixed Rate	Floating Rate
May 1998 — April 2001	$230,000,000	7%	Average of three-month Swiss Franc LIBOR, Deutsche Mark and Australian Dollar plus 300 basis points
May 2001 — April 2008	$230,000,000	7%	U.S. three-month LIBOR plus 300 basis points

If the floating rate is less than the fixed rate, the counterparty will pay us accordingly. If the floating rate exceeds the fixed rate, we will pay the counterparty. The interest rate swap agreement contains a "knockout provision" whereby the agreement will terminate on or after May 1, 2001 if the average closing price for the previous twenty business days for shares of Chesapeake's common stock is greater than or equal to $7.50 per share. The agreement also provides for a maximum floating rate of 8.5% from May 2001 through April 2008.

Based on current market prices for Chesapeake common stock, we expect the interest rate swap agreement will terminate in May 2001 under the knockout provision of the agreement discussed above. The fair value of the swap arrangement at December 31, 2000 was not material. Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the swap agreement.

Concentration of Credit Risk

Other financial instruments which potentially subject us to concentrations of credit risk consist principally of cash, short-term investments in debt instruments and trade 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 the 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. The cash and cash equivalents are deposited with major banks or institutions with high credit ratings.

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, 1999 and 2000 was $921.4 million and $920.7 million, respectively, compared to approximate fair values of $838.7 million and $894.7 million, respectively. The carrying value of other long-term debt approximates its fair value as interest rates are primarily variable, based on prevailing market rates. We estimate the fair value of our convertible preferred stock, which was issued in April 1998, using quoted market prices. Our carrying amount for such preferred stock at December 31, 1999 and 2000 was $229.8 million and $31.2 million, compared to an approximate fair value of $119.0 million and $49.6 million, respectively.

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, 1999

	U.S.	Canada	Combined
		($ in thousands)	
Oil and gas properties:			
Proved	$ 2,193,492	$121,856	$ 2,315,348
Unproved	36,225	3,783	40,008
Total	2,229,717	125,639	2,355,356
Less accumulated depreciation, depletion and amortization	(1,645,185)	(25,357)	(1,670,542)
Net capitalized costs	$ 584,532	$100,282	$ 684,814

December 31, 2000

	U.S.	Canada	Combined
		($ in thousands)	
Oil and gas properties:			
Proved	$ 2,453,316	$137,196	$ 2,590,512
Unproved	23,673	2,012	25,685
Total	2,476,989	139,208	2,616,197
Less accumulated depreciation, depletion and amortization	(1,737,892)	(32,935)	(1,770,827)
Net capitalized costs	$ 739,097	$106,273	$ 845,370

Unproved properties not subject to amortization at December 31, 1999 and 2000 consisted mainly of lease acquisition costs. We capitalized approximately $6.5 million, $3.5 million and $2.4 million of interest during 1998, 1999 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.

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, 1998

	U.S.	Canada	Combined
		($ in thousands)	
Development and leasehold costs	$145,657	$ 4,584	$150,241
Exploration costs	63,245	5,427	68,672
Acquisition costs:			
Proved	662,104	78,176	740,280
Unproved	23,834	2,535	26,369
Sales of oil and gas properties	(15,712)	—	(15,712)
Capitalized internal costs	5,262	—	5,262
Total	$884,390	$90,722	$975,112

Year Ended December 31, 1999

	U.S.	Canada	Combined
		($ in thousands)	
Development and leasehold costs	$ 92,582	$31,536	$124,118
Exploration costs	23,651	42	23,693
Acquisition costs:			
Proved	47,993	4,100	52,093
Unproved	2,747	—	2,747
Sales of oil and gas properties	(44,822)	(813)	(45,635)
Capitalized internal costs	2,710	—	2,710
Total	$124,861	$34,865	$159,726

Year Ended December 31, 2000

	U.S.	Canada	Combined
		($ in thousands)	
Development and leasehold costs	$138,285	$13,559	$151,844
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	6,958	—	6,958
Total	$247,272	$13,569	$260,841

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 1998, 1999 and 2000. The following table includes revenues and expenses associated directly with our oil and gas producing activities. It does not include any allocation of our interest 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, 1998

	U.S.	Canada	Combined
		($ in thousands)	
Oil and gas sales	$ 248,909	$ 7,978	$ 256,887
Production expenses	(49,368)	(1,834)	(51,202)
Production taxes	(8,295)	—	(8,295)
Impairment of oil and gas properties	(810,610)	(15,390)	(826,000)
Depletion and depreciation	(143,283)	(3,361)	(146,644)
Imputed income tax (provision) benefit(a)	285,981	5,673	291,654
Results of operations from oil and gas producing activities	$(476,666)	$ (6,934)	$(483,600)

Year Ended December 31, 1999

	U.S.	Canada	Combined
		($ in thousands)	
Oil and gas sales	$ 266,468	$ 13,977	$ 280,445
Production expenses	(44,165)	(2,133)	(46,298)
Production taxes	(13,264)	—	(13,264)
Depletion and depreciation	(88,901)	(6,143)	(95,044)
Imputed income tax (provision) benefit(a)	(45,052)	(2,565)	(47,617)
Results of operations from oil and gas producing activities	$ 75,086	$ 3,136	$ 78,222

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) benefit(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 benefits will be realized.

Capitalized costs, less accumulated amortization and related deferred income taxes, cannot exceed an amount equal to the sum of the present value (discounted at 10%) 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. At December 31, 1998 capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues for our proved reserves, net of related income tax considerations, resulting in writedowns in the carrying value of oil and gas properties of $826 million.

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, 1998, Williamson Petroleum Consultants, Inc., Ryder Scott Company L.P., H.J. Gruy and Associates, Inc. and our internal reservoir engineers evaluated 63%, 12%, 1% and 24% of the combined discounted future net revenues from our estimated proved reserves, respectively.
- As of December 31, 1999, Williamson, Ryder Scott, and our internal reservoir engineers evaluated 50%, 16%, and 34% of the combined discounted future net revenues from our estimated proved reserves, respectively.
- As of December 31, 2000, Williamson, Ryder Scott, Lee Keeling and Associates and our internal reservoir engineers evaluated 31%, 25%, 16% and 28% of our combined discounted future net revenues from our estimated proved reserves, respectively.

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 1998, 1999 and 2000:

December 31, 1998

	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	18,226	339,118	448,473	—	—	—	18,226	339,118	448,473
Extensions, discoveries and other additions	3,448	90,879	111,567	—	—	—	3,448	90,879	111,567
Revisions of previous estimates	(4,082)	(60,477)	(84,969)	—	—	—	(4,082)	(60,477)	(84,969)
Production	(5,975)	(86,681)	(122,531)	(1)	(7,740)	(7,746)	(5,976)	(94,421)	(130,277)
Sale of reserves-in-place	(30)	(3,515)	(3,695)	—	—	—	(30)	(3,515)	(3,695)
Purchase of reserves-in-place	10,973	444,694	510,532	34	239,513	239,717	11,007	684,207	750,249
Proved reserves, end of period	22,560	724,018	859,377	33	231,773	231,971	22,593	955,791	1,091,348
Proved developed reserves:									
Beginning of period	10,087	178,082	238,604	—	—	—	10,087	178,082	238,604
End of period	18,003	552,953	660,971	33	105,990	106,188	18,036	658,943	767,159

December 31, 1999

	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	22,560	724,018	859,377	33	231,773	231,971	22,593	955,791	1,091,348
Extensions, discoveries and other additions	4,593	158,801	186,359	—	37,835	37,835	4,593	196,636	224,194
Revisions of previous estimates	3,404	59,904	80,328	—	(98,571)	(98,571)	3,404	(38,667)	(18,243)
Production	(4,147)	(96,873)	(121,755)	—	(11,737)	(11,737)	(4,147)	(108,610)	(133,492)
Sale of reserves-in-place	(4,371)	(31,616)	(57,842)	(33)	(796)	(994)	(4,404)	(32,412)	(58,836)
Purchase of reserves-in-place	2,756	64,350	80,886	—	19,738	19,738	2,756	84,088	100,624
Proved reserves, end of period	24,795	878,584	1,027,353	—	178,242	178,242	24,795	1,056,826	1,205,595
Proved developed reserves:									
Beginning of period	18,003	552,953	660,971	33	105,990	106,188	18,036	658,943	767,159
End of period	17,750	627,120	733,620	—	136,203	136,203	17,750	763,323	869,823

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
Chesapeake and Gothic on a combined basis:									
Proved reserves, end of period	25,565	1,343,976	1,497,364	—	158,964	158,964	25,565	1,502,940	1,656,328
Proved developed reserves, end of period	17,012	985,247	1,087,319	—	118,688	118,688	17,012	1,103,935	1,206,007

During 1999, Chesapeake acquired approximately 101 bcfe of proved reserves through purchases of oil and gas properties for consideration of $52 million. We also sold 59 bcfe of proved reserves for consideration of approximately $46 million. During 1999, we recorded upward revisions of 80 bcfe to the December 31, 1998 estimates of our U.S. reserves, and downward revisions of 99 bcfe to the December 31, 1998 estimates of our Canadian reserves, for a total revision of 19 bcfe, or approximately 1.7%. The upward revisions to our U.S. reserves were caused by higher oil and gas prices at December 31, 1999, and actual performance in excess of predicted performance. Higher prices extend the economic lives of the underlying oil and gas properties and thereby increase the estimated future reserves. The downward revisions to our Canadian reserves were caused by a reduction of our proved undeveloped locations and an increase in projected transportation and operating costs in Canada, which decreased the economic lives of the underlying properties.

During 2000, Chesapeake acquired 107.9 bcfe of proved reserves for consideration of $75.3 million. 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 28.0 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.

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, 1998

	U.S.	Canada	Combined
		($ in thousands)	
Future cash inflows(a)	$ 1,374,280	$ 474,143	$ 1,848,423
Future production costs	(432,876)	(52,493)	(485,369)
Future development costs	(124,717)	(29,634)	(154,351)
Future income tax provision	(6,464)	(143,747)	(150,211)
Net future cash flows	810,223	248,269	1,058,492
Less effect of a 10% discount factor	(303,096)	(132,281)	(435,377)
Standardized measure of discounted future net cash flows	$ 507,127	$ 115,988	$ 623,115
Discounted (at 10%) future net cash flows before income taxes	$ 504,148	$ 156,843	$ 660,991

December 31, 1999

	U.S.	Canada	Combined
		($ in thousands)	
Future cash inflows(b)	$ 2,555,241	$ 437,928	$ 2,993,169
Future production costs	(671,431)	(195,464)	(866,895)
Future development costs	(209,921)	(20,950)	(230,871)
Future income tax provision	(219,866)	(29,410)	(249,276)
Net future cash flows	1,454,023	192,104	1,646,127
Less effect of a 10% discount factor	(545,125)	(94,390)	(639,515)
Standardized measure of discounted future net cash flows	$ 908,898	$ 97,714	$ 1,006,612
Discounted (at 10%) future net cash flows before income taxes	$ 991,748	$ 97,748	$ 1,089,496

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(d)

(a) Calculated using weighted average prices of $10.48 per barrel of oil and $1.68 per mcf of gas.

(b) Calculated using weighted average prices of $24.72 per barrel of oil and $2.25 per mcf of gas.

(c) Calculated using weighted average prices of $26.41 per barrel of oil and $10.12 per mcf of gas.

(d) Based on the adjusted cash spot price for natural gas and oil at December 31, 2000. These prices are significantly higher than the prices received in 2000.

In January 2001, Chesapeake acquired Gothic Energy Corporation. Gothic reported $858 million as its standardized measure of discounted future net cash flows and $1.27 billion as its discounted future net cash flows before income taxes at December 31, 2000.

	U.S.	Canada	Combined
		($ in thousands)	
Chesapeake and Gothic on a combined basis at December 31, 2000:			
Future cash flows	$14,341,562	$1,540,158	$15,881,720
Future production costs	(2,128,696)	(79,427)	(2,208,123)
Future development costs	(336,619)	(21,185)	(357,804)
Future income tax provision	(4,091,330)	(447,887)	(4,539,217)
Net future cash flows	7,784,917	991,659	8,776,576
Less effect of a 10% discount factor	(3,352,024)	(503,718)	(3,855,742)
Standard measure of discounted future net cash flows	$ 4,432,893	$ 487,941	$ 4,920,834
Discounted (at 10%) future net cash flows before income taxes	$ 6,631,731	$ 680,800	$ 7,312,531

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

December 31, 1998

	U.S.	Canada	Combined
		($ in thousands)	
Standardized measure, beginning of period	$ 430,110	$ —	$ 430,110
Sales of oil and gas produced, net of production costs	(191,246)	(6,144)	(197,390)
Net changes in prices and production costs	(189,817)	—	(189,817)
Extensions and discoveries, net of production and development costs	85,464	—	85,464
Changes in future development costs	72,279	—	72,279
Development costs incurred during the period that reduced future development costs	28,191	—	28,191
Revisions of previous quantity estimates	(64,770)	—	(64,770)
Purchase of reserves-in-place	288,694	164,821	453,515
Sales of reserves-in-place	(3,079)	—	(3,079)
Accretion of discount	46,651	—	46,651
Net change in income taxes	39,377	(40,855)	(1,478)
Changes in production rates and other	(34,727)	(1,834)	(36,561)
Standardized measure, end of period	$ 507,127	$ 115,988	$ 623,115

December 31, 1999

	U.S.	Canada	Combined
		($ in thousands)	
Standardized measure, beginning of period	$ 507,127	$ 115,988	$ 623,115
Sales of oil and gas produced, net of production costs	(209,039)	(11,844)	(220,883)
Net changes in prices and production costs	320,123	(55,156)	264,967
Extensions and discoveries, net of production and development costs	200,787	14,333	215,120
Changes in future development costs	(15,011)	20,679	5,668
Development costs incurred during the period that reduced future development costs	14,114	1,985	16,099
Revisions of previous quantity estimates	88,250	(49,034)	39,216
Purchase of reserves-in-place	66,895	18,476	85,371
Sales of reserves-in-place	(25,838)	(920)	(26,758)
Accretion of discount	50,415	15,684	66,099
Net change in income taxes	(85,828)	40,821	(45,007)
Changes in production rates and other	(3,097)	(13,298)	(16,395)
Standardized measure, end of period	$ 908,898	$ 97,714	$ 1,006,612

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. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 1999 and 2000 are as follows ($ in thousands except per share data):

	Quarters Ended			
	March 31, 1999	June 30, 1999	September 30, 1999	December 31, 1999
Net sales	$ 65,677	$80,892	$102,140	$106,237
Gross profit[(a)]	7,067	25,765	36,498	38,190
Net income (loss)	(11,950)	8,147	18,115	18,954
Net income (loss) per share:				
Basic	(0.17)	0.04	0.14	0.15
Diluted	(0.17)	0.04	0.13	0.14

	Quarters Ended			
	March 31, 2000	June 30, 2000	September 30, 2000	December 31, 2000
Net sales	$114,661	$134,463	$168,182	$210,646
Gross profit[(a)]	40,975	53,142	76,918	107,734
Net income	21,202	31,634	54,689	348,045[(b)]
Net income per share:				
Basic	.27	.26	.33	2.28
Diluted	.15	.22	.31	2.12

(a) Total revenue less total operating costs.

(b) In the fourth quarter of 2000, we eliminated our valuation allowance resulting in the recognition of a $265 million income tax benefit. Based upon recent results of operations and anticipated improvement in Chesapeake's outlook for sustained profitability, we 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.

13. Subsequent Events

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 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 (1.1 million shares as of March 15, 2001 at an average price of $12.28 per share) based on the merger exchange ratio. Prior to the merger, Chesapeake purchased substantially all of Gothic's 14.125% senior secured discount notes for total consideration valued at $80.8 million in cash and Chesapeake common stock. Prior to the merger, we also purchased $31.6 million principal amount of 11.125% senior secured notes due 2005 issued by Gothic's operating subsidiary and guaranteed by Gothic. The consideration for these purchases consisted of cash and Chesapeake common stock valued at a total of $34.8 million. In February 2001, we purchased $1.0 million principal amount of Gothic senior secured notes tendered at 101%. There remain outstanding $202.3 million principal amount of the 11.125% senior secured notes, all of which are secured by Gothic's oil and gas properties. Chesapeake has not assumed any payment obligations with respect to the notes. The parties executed a definitive merger agreement on September 8, 2000, as amended on October 1, 2000, and Gothic's shareholders approved the merger at a special meeting on December 12, 2000.

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, 1998:					
Allowance for doubtful accounts	$ 691	$ 1,589	$ 1,000	$ 71	$ 3,209
Valuation allowance for deferred tax assets	$ 77,934	$380,969	$ —	$ —	$458,903
December 31, 1999:					
Allowance for doubtful accounts	$ 3,209	$ 9	$ —	$ —	$ 3,218
Valuation allowance for deferred tax assets	$458,903	$ —	$(5,931)(a)	$ 10,956	$442,016
December 31, 2000:					
Allowance for doubtful accounts	$ 3,218	$ 256	$ —	$ 2,389	$ 1,085
Valuation allowance for deferred tax assets	$442,016	$ —	$ —	$442,016(b)	$ —

(a) At December 31, 1998, $5.9 million of the valuation allowance was related to our Canadian deferred tax assets. During 1999, this valuation allowance was eliminated as part of a purchase price reallocation related to a 1998 acquisition.

(b) 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.

CHESAPEAKE ENERGY CORPORATION

PRO FORMA COMBINED FINANCIAL STATEMENTS

Summary

Chesapeake Energy Corporation completed the acquisition of Gothic Energy Corporation on January 16, 2001, by merging a wholly-owned subsidiary of Chesapeake into Gothic. We issued a total of 4.0 million shares of our common stock 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 (1.1 million shares as of March 15, 2001 at an average price of $12.28 per share) based on the merger exchange ratio. Prior to the merger, Chesapeake purchased substantially all of Gothic's 14.125% senior secured discount notes for total consideration valued at $80.8 million in cash and Chesapeake common stock. We also purchased prior to the merger $31.6 million principal amount of 11.125% senior secured notes due 2005 issued by Gothic's operating subsidiary and guaranteed by Gothic. The consideration for these purchases consisted of cash and Chesapeake common stock valued at a total of $34.8 million. In February 2001, we purchased an additional $1.0 million principal amount of Gothic Production senior secured notes tendered pursuant to a change-of-control offer to purchase for 101%. There remain outstanding $202.3 million principal amount of the Gothic Production 11.125% senior secured notes. The notes are collateralized by Gothic's oil and gas properties. Chesapeake has not assumed any payment obligations with respect to the notes. Gothic's preferred stock, all of which was owned by Chesapeake prior to the merger, remains outstanding. As part of the merger, the terms of the Gothic preferred stock were amended to eliminate cumulative dividends and conversion rights. The parties executed a definitive merger agreement on September 8, 2000, as amended on October 1, 2000, and Gothic's shareholders approved the merger at a special meeting on December 12, 2000.

The following unaudited pro forma combined financial statements are derived from the historical financial statements of Chesapeake Energy Corporation and Gothic Energy Corporation. The pro forma combined statements of operations for the year ended December 31, 2000 reflect the Gothic acquisition, accounted for as a purchase, as if the acquisition occurred on January 1, 2000. The pro forma combined balance sheet at December 31, 2000 reflects the consummation of the Gothic acquisition as if it occurred on December 31, 2000. The unaudited pro forma combined financial data should be read in conjunction with the notes thereto and the historical financial statements of Chesapeake and Gothic, including the notes thereto.

The unaudited pro forma combined financial statements do not purport to be indicative of the results of operations that would actually have occurred if the transaction described had occurred as presented in such statements or that may occur in the future. In addition, future results may vary significantly from the results reflected in such statements due to general economic conditions, oil and gas commodity prices, Chesapeake's ability to successfully integrate the operations of Gothic with its current business and several other factors, many of which are beyond Chesapeake's control.

CHESAPEAKE ENERGY CORPORATION

UNAUDITED PRO FORMA COMBINED BALANCE SHEET
as of December 31, 2000
($ in thousands)

	Historical		Pro Forma	
	Chesapeake	Gothic	Adjustments	As Adjusted
ASSETS				
Current assets	$ 166,926	$ 22,229	$ 58 (a) (1,010) (j)	$ 188,203
Property, plant and equipment:				
Proved properties	2,590,512	275,827	87,374 (a) (336) (k)	2,953,377
Unproved properties	25,685	6,191	3,809 (a)	35,685
Accumulated DD&A	(1,770,827)	(75,003)	75,003 (a)	(1,770,827)
Net proved and unproved properties	845,370	207,015	165,850	1,218,235
Other, net	42,864	4,737	(4,587) (a)	43,014
Total property, plant and equipment, net	888,234	211,752	161,263	1,261,249
Investment in Gothic	126,434	—	(125,521) (a) (913) (k)	—
Deferred tax asset	229,823	—	(20) (j) 1,280 (i)	231,083
Other	29,009	8,675	(8,675) (a) (2,800) (i)	26,209
Total assets	$ 1,440,426	$ 242,656	$ 23,662	$ 1,706,744
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities	$ 162,701	$ 11,209	$ 12,000 (a) (1,137) (a) (1,249) (k) 400 (i)	$ 183,924
Long-term debt	944,845	321,676	(112,400) (a) 6,434 (a) (1,060) (j)	1,159,495
Deferred income tax liabilities	11,850	—	—	11,850
Other liabilities	7,798	2,835	—	10,633
Stockholders equity:				
Preferred stock	31,202	55,139	(55,139) (a)	31,202
Common stock	1,578	233	(233) (a) 40 (a)	1,618
Warrants	—	—	1,500 (a)	1,500
Paid-in capital	963,584	44,830	(44,830) (a) 27,960 (a)	991,544
Accumulated earnings (deficit)	(659,286)	(193,266)	193,266 (a) (1,920) (i) 30 (j)	(661,176)
Accumulated other comprehensive income (loss)	(3,901)	—	—	(3,901)
Less treasury stock	(19,945)	—	—	(19,945)
Total stockholders' equity (deficit)	313,232	(93,064)	120,674	340,842
Total liabilities and stockholders' equity (deficit)	$ 1,440,426	$ 242,656	$ 23,662	$ 1,706,744

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

CHESAPEAKE ENERGY CORPORATION

UNAUDITED PRO FORMA COMBINED STATEMENT OF OPERATIONS
Year Ended December 31, 2000
(in thousands, except per share data)

	Historical		Pro Forma	
	Chesapeake	Gothic	Adjustments	As Adjusted
Revenues:				
Oil and gas sales	$ 470,170	$ 83,065	$ —	$ 553,235
Oil and gas marketing sales	157,782	—	—	157,782
Well operations	—	2,680	(2,680) (h)	—
Total revenues	627,952	85,745	(2,680)	711,017
Operating costs:				
Production expenses and taxes	74,925	11,800	—	86,725
General and administrative	13,177	5,763	(2,680) (h)	16,260
Oil and gas marketing expenses	152,309	—	—	152,309
Oil and gas depreciation, depletion and amortization	101,291	21,817	25,286 (b)	148,394
Depreciation and amortization of other assets	7,481	2,632	(2,582) (c)	7,531
Total operating costs	349,183	42,012	20,024	411,219
Income from operations	278,769	43,733	(22,704)	299,798
Other income (expense):				
Interest and other income	3,649	280	—	3,929
Interest expense	(86,256)	(37,931)	14,427 (g)	(106,987)
			2,773 (l)	
Total other income (expense)	(82,607)	(37,651)	17,200	(103,058)
Income (loss) before income taxes	196,162	6,082	(5,504)	196,740
Income tax expense (benefit)	(259,408)	—	(2,202) (d)	(261,610)
Net income (loss)	455,570	6,082	(3,302)	458,350
Preferred stock dividends	(8,484)	(9,527)	9,527 (f)	(8,484)
Gain (loss) on redemption of preferred stock	6,574	—	—	6,574
Net income (loss) available to common shareholders	$ 453,660	$ (3,445)	$ 6,225	$ 456,440
Earnings (loss) per common share(e):				
Basic	$ 3.52			$ 3.27
Assuming dilution	$ 3.01			$ 2.83
Weighted average common and common equivalent shares outstanding(e):				
Basic	128,993			139,536
Assuming dilution	151,564			162,107

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

NOTES TO UNAUDITED PRO FORMA COMBINED FINANCIAL STATEMENTS

(a) The purchase price reflects:

- the issuance of 4.0 million shares of Chesapeake common stock, valued at $7.00 per share, the closing price of Chesapeake common stock on the day the merger was announced, in exchange for all outstanding shares of Gothic common stock (other than shares of Gothic common stock held by Chesapeake);
- the issuance of Chesapeake warrants and options to purchase 2.9 million shares of Chesapeake common stock in exchange for all of the outstanding warrants and options to purchase shares of Gothic common stock based on the exchange ratio of 0.1908 of a share of Chesapeake common stock for each share of Gothic common stock;
- Chesapeake's investment in Gothic preferred and common stock, which has a carrying value of $10.0 million;
- Chesapeake's investment in Gothic debt. Chesapeake estimated the fair value of the Gothic Production senior secured notes equalled 106% of their face value; and
- the incurrence of acquisition costs of approximately $12.0 million.

Below is a summary of the purchase price allocation to the estimated fair value of the assets acquired and liabilities assumed ($ in 000's):

Issuance of common stock	$ 28,000
Investment in Gothic preferred and common stock	10,000
Fair value of Chesapeake warrants	1,500
Investment in Gothic senior secured discount notes	80,761
Investment in Gothic Production senior secured notes	34,760
Other acquisition costs	12,000
Purchase price	$167,021

	Gothic Book Value	Estimated Fair Value	Pro Forma Adjustment
Current assets	$ 22,229	$ 22,287	$ 58
Property and equipment — proved properties	275,827	363,201	87,374
Property and equipment — unproved properties	6,191	10,000	3,809
Accumulated DD&A	(75,003)	—	75,003
Other property and equipment	4,737	150	(4,587)
Other assets	8,675	—	(8,675)
Current liabilities	(11,209)	(10,072)	1,137
Debt, less $112.4 million of Gothic notes held by Chesapeake	(209,276)	(215,710)	(6,434)
Other liabilities	(2,835)	(2,835)	—
	$ 19,336	$ 167,021	$147,685

(b) To adjust DD&A expense of oil and gas properties using a rate of $0.92 per mcfe. This combined rate reflects the impact of the allocation of purchase price to Gothic's proved oil and gas properties.

(c) To adjust depreciation and amortization expense in connection with the allocation of purchase price to the estimated fair value of Gothic's other property and equipment and other assets. A significant portion of Gothic's depreciation and amortization expense was related to (1) telemetry assets which have been classified to oil and gas properties (and depreciated accordingly), and (2) debt issue costs that will have no future value to Chesapeake. The remaining fair value of other property and equipment will be depreciated over a three-year period.

(d) To record tax effects of the pro forma adjustments at a statutory rate of 40% (federal and state).

(e) Basic and diluted earnings per share have been calculated assuming the transaction was consummated at the beginning of the period and are calculated as follows (in 000's):

	Year Ended December 31, 2000
Chesapeake's basic shares outstanding (as reported)	128,993
Adjustment to reflect issuance of common stock to acquire Gothic debt at January 1, 2000	6,543
Issuance of common stock to Gothic — merger consideration	4,000
Basic shares outstanding — as adjusted	139,536
Chesapeake's diluted shares outstanding (as reported)	151,564
Adjustment to reflect issuance of common stock to acquire Gothic debt at January 1, 2000	6,543
Issuance of common stock to Gothic — merger consideration	4,000
Diluted shares outstanding — as adjusted	162,107

(f) To eliminate dividends on Gothic's preferred stock held by Chesapeake.

(g) To eliminate interest expense related to the Gothic senior discount notes and Gothic Production senior secured notes acquired by Chesapeake.

(h) To reclassify overhead reimbursements recognized by Gothic as operator of certain oil and gas properties and reported as well operations revenue. These reimbursements have been reclassified as a reduction to general and administrative expenses to conform with Chesapeake's presentation of similar reimbursements.

(i) To record the remaining financing fees (net of income tax) incurred by Chesapeake to establish a standby credit facility to fund purchases of Gothic Production senior secured notes tendered after the merger pursuant to a change-of-control offer to purchase the notes at 101% principal amount. The standby credit facility was not utilized, and therefore the associated fees were expensed when the holders' change-of-control put options expired in February 2001. Chesapeake incurred $2.8 million in financing fees prior to December 31, 2000 and $0.4 million subsequent thereto.

(j) To record the purchase of $1.0 million principal amount of Gothic Production senior secured notes which were tendered pursuant to the post-acquisition change-of-control offer to purchase at 101%. These notes were adjusted to their market value of 106% in the purchase price allocation (see note a). The gain on extinguishment is tax effected.

(k) To adjust the purchase price allocation and accrued merger-related costs for $1.24 million incurred through December 31, 2000. This amount includes $913 thousand paid by Chesapeake, included in Other Assets, and $336 thousand paid and expensed by Gothic.

(l) To record amortization of the 6% premium on remaining Gothic senior secured notes held by third parties.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and
Stockholder of Gothic Energy Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, stockholders' equity (deficit) and cash flows present fairly, in all material respects, the financial position of Gothic Energy Corporation ("Gothic") and Subsidiary at December 31, 1999 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of Gothic's management; our responsibility is to express an opinion on these financial statements 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 audits 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.

Chesapeake Energy Corporation ("Chesapeake") acquired all of the outstanding common stock and related outstanding warrants and options to acquire common stock of Gothic and Gothic was merged into a wholly owned subsidiary of Chesapeake.

PricewaterhouseCoopers LLP
Tulsa, Oklahoma
February 26, 2001

GOTHIC ENERGY CORPORATION AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS

	December 31, 1999	December 31, 2000
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,583	$ 2,000
Natural gas and oil receivables	8,163	18,273
Receivable from officers and employees	77	1,764
Other	624	192
Total Current Assets	11,447	22,229
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties on full cost method:		
Properties being amortized	258,818	275,827
Unproved properties not subject to amortization	5,473	6,191
Equipment, furniture and fixtures	6,123	6,385
Accumulated depreciation, depletion and amortization	(54,170)	(76,651)
PROPERTY AND EQUIPMENT, NET	216,244	211,752
OTHER ASSETS, NET	10,706	8,675
TOTAL ASSETS	$ 238,397	$ 242,656
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable trade	$ 4,630	$ 203
Revenues payable	6,047	6,349
Accrued interest	4,357	4,366
Other accrued liabilities	893	291
Total Current Liabilities	15,927	11,209
LONG-TERM DEBT	319,857	321,676
GAS IMBALANCE LIABILITY	3,648	2,835
COMMITMENTS AND CONTINGENCIES (NOTES 1 AND 6)		
STOCKHOLDERS' EQUITY (DEFICIT):		
Series B Preferred stock, par value $.05, authorized 165,000 shares; 59,216 and 66,674 shares issued and outstanding, respectively	45,612	55,139
Common stock, par value $.01, authorized 100,000,000 shares; 18,685,765 and 23,305,094 shares issued and outstanding, respectively	187	233
Additional paid in capital	42,987	44,830
Accumulated deficit	(189,821)	(193,266)
Total Stockholders' Equity (Deficit)	(101,035)	(93,064)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 238,397	$ 242,656

See accompanying notes to consolidated financial statements.

GOTHIC ENERGY CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENT OF OPERATIONS

	Years Ended December 31,		
	1998	1999	2000
	($ in thousands, except per share data)		
REVENUES:			
Natural gas and oil sales	$ 50,714	$ 52,967	$ 83,065
Well operations	2,319	2,657	2,680
Total revenues	53,033	55,624	85,745
COSTS AND EXPENSES:			
Lease operating expense	12,129	9,605	11,800
Depletion, depreciation and amortization	24,001	20,969	22,621
General and administrative expense	3,823	4,675	4,551
Investment banking and related fees	—	638	1,212
Provision for impairment of natural gas and oil properties	76,000	—	—
Operating income (loss)	(62,920)	19,737	45,561
Interest expense and amortization of debt issuance costs	(35,438)	(37,988)	(39,759)
Interest and other income	433	942	280
Loss on sale of investments	(305)	—	—
INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(98,230)	(17,309)	6,082
LOSS ON EARLY EXTINGUISHMENT OF DEBT	31,459	—	—
NET INCOME (LOSS)	(129,689)	(17,309)	6,082
PREFERRED DIVIDEND	5,599	6,820	7,678
PREFERRED DIVIDEND — AMORTIZATION OF PREFERRED DISCOUNT	5,095	1,847	1,849
NET LOSS AVAILABLE FOR COMMON SHARES	$(140,383)	$(25,976)	$ (3,445)
LOSS PER COMMON SHARE BEFORE EXTRAORDINARY ITEM, BASIC AND DILUTED	$ (6.70)	$ (1.51)	$ (0.17)
LOSS ON EARLY EXTINGUISHMENT OF DEBT	(1.93)	—	—
NET LOSS PER COMMON SHARE, BASIC AND DILUTED	$ (8.63)	$ (1.51)	$ (0.17)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	16,262	17,219	20,637

See accompanying notes to consolidated financial statements.

GOTHIC ENERGY CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY (DEFICIT)

	Years Ended December 31,		
	1998	1999	2000
	($ in thousands)		
PREFERRED STOCK:			
Balance beginning of period	$ —	$ 36,945	$ 45,612
Preferred stock dividend — Series B	4,187	6,820	7,678
Preferred dividend — amortization of discount — Series B	1,231	1,847	1,849
Issuance of Series A preferred stock	33,909	—	—
Redemption of Series A preferred stock	(33,909)	—	—
Issuance of Series B preferred stock	31,527	—	—
Balance, end of period	$ 36,945	$ 45,612	$ 55,139
COMMON STOCK:			
Balance, beginning of period	$ 162	$ 162	$ 187
Issuance of common stock on exercise of options	—	—	44
Issuance of common stock on exercise of warrants	—	—	2
Issuance of common stock on warrant conversion	—	25	—
Balance, end of period	$ 162	$ 187	$ 233
ADDITIONAL PAID-IN CAPITAL:			
Balance, beginning of period	$ 36,043	$ 42,996	$ 42,987
Issuance of common stock on exercise of options	—	—	1,695
Issuance of common stock as employee severance	—	16	—
Issuance of common stock on exercise of warrants	—	—	148
Issuance of common stock on warrant conversion	—	(25)	—
Issuance of Series A preferred stock	(20)	—	—
Warrants issued in connection with Series A preferred	941	—	—
Warrants issued in connection with Amoco acquisition	1,153	—	—
Warrants issued in connection with Series B preferred	4,879	—	—
Balance, end of period	$ 42,996	$ 42,987	$ 44,830
ACCUMULATED DEFICIT:			
Balance, beginning of period	$ (23,462)	$(163,845)	$(189,821)
Net income (loss)	(129,689)	(17,309)	6,082
Preferred stock dividend — Series B	(4,187)	(6,820)	(7,678)
Preferred stock dividend — amortization of discount — Series B	(1,231)	(1,847)	(1,849)
Preferred stock dividend — Series A	(1,412)	—	—
Preferred stock dividend — amortization of discount — Series A	(3,864)	—	—
Balance, end of period	$(163,845)	$(189,821)	$(193,266)
ACCUMULATED OTHER COMPREHENSIVE INCOME:			
Balance, beginning of period	$ (121)	$ —	$ —
Realized loss on available for sale investments	121	—	—
Balance, end of period	$ —	$ —	$ —
NOTE RECEIVABLE:			
Balance, beginning of period	$ (169)	$ (179)	$ —
Advance to officer	(10)	—	—
Forgiveness of officer note receivable	—	179	—
Balance, end of period	$ (179)	$ —	$ —
TOTAL STOCKHOLDERS' EQUITY (DEFICIT)	$ (83,921)	$(101,035)	$ (93,064)

See accompanying notes to consolidated financial statements.

GOTHIC ENERGY CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENT OF CASH FLOWS

	Years Ended December 31, 1998	1999	2000
	($ in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$(129,689)	$(17,309)	$ 6,082
ADJUSTMENTS TO RECONCILE NET LOSS TO NET CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	24,001	20,969	22,621
Amortization of discount and loan costs	1,994	1,769	1,828
Provision for impairment of natural gas and oil properties	76,000	—	—
Accretion of interest on discount notes	6,023	9,678	10,819
Loss on early extinguishment of debt	31,459	—	—
Other	—	179	—
CHANGES IN ASSETS AND LIABILITIES:			
Increase in accounts receivable	(4,009)	(949)	(11,797)
(Increase) decrease in other current assets	(143)	(403)	432
Increase (decrease) in accounts and revenues payable	5,605	1,438	(4,125)
Increase (decrease) in gas imbalance and other liabilities	65	(2,532)	(813)
Increase (decrease) in accrued liabilities	411	639	(593)
(Increase) decrease in other assets	(150)	228	202
NET CASH PROVIDED BY OPERATING ACTIVITIES	11,567	13,707	24,656
NET CASH USED BY INVESTING ACTIVITIES:			
Collection of note receivable from officer and director	167	—	—
Purchase of available-for-sale investments	(462)	—	—
Proceeds from sale of investments	1,359	—	—
Proceeds from sale of property and equipment	44,678	2,228	1,877
Purchase of property and equipment	(218,738)	(3,413)	(939)
Property development costs	(18,379)	(21,056)	(19,066)
NET CASH USED BY INVESTING ACTIVITIES	(191,375)	(22,241)	(18,128)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from short-term borrowings	60,000	—	—
Payments of short-term borrowings	(60,000)	—	—
Proceeds from long-term borrowings	431,290	31,000	13,473
Payments of long-term borrowings	(259,884)	(22,000)	(22,473)
Redemption of preferred stock, net	(40,809)	—	—
Proceeds from sale of preferred stock, net	73,475	—	—
Proceeds from exercise of stock options	—	—	1,739
Proceeds from exercise of stock warrants	—	—	150
Payment of loan and offering fees	(38,535)	(172)	—
Other	(162)	—	—
NET CASH PROVIDED (USED) BY FINANCING ACTIVITIES	165,375	8,828	(7,111)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(14,433)	294	(583)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	16,722	2,289	2,583
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 2,289	$ 2,583	$ 2,000
SUPPLEMENTAL DISCLOSURE OF INTEREST PAID	$ 23,063	$ 26,541	$ 27,104

See accompanying notes to consolidated financial statements.

GOTHIC ENERGY CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General and Accounting Policies

Organization and Nature of Operations

The consolidated financial statements include the accounts of Gothic Energy Corporation, ("Gothic Energy"), a holding company, and its wholly owned subsidiary, Gothic Production Corporation ("Gothic Production") since its formation in April of 1998 (collectively referred to as "Gothic" or the "Company"). All significant intercompany balances and transactions have been eliminated. Through January 15, 2001, Gothic Production was an independent energy company engaged in the business of acquiring, developing and exploiting natural gas and oil reserves in Oklahoma, Texas, New Mexico and Kansas.

On January 16, 2001, Gothic Energy Corporation merged with Chesapeake Merger 2000 Corp., a wholly owned subsidiary of Chesapeake Energy Corporation ("Chesapeake") (the "Merger"). Gothic was the surviving corporation in the Merger and since January 16, 2001 has been a wholly owned subsidiary of Chesapeake. Chesapeake had previously acquired all of Gothic's Series B Preferred Stock, substantially all of Gothic Energy's 14⅛% Senior Secured Discount Notes, and $31.6 million of Gothic Production's 11⅛% Senior Secured Notes. Under terms of the Merger, Chesapeake issued 4.0 million shares of common stock to the Gothic stockholders, with an exchange ratio of 0.1908 of a Chesapeake share for each share of Gothic common stock.

Use of 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 date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. In addition, accrued and deferred lease operating expenses, gas imbalance liabilities, natural gas and oil reserves (see Note 11) and the tax valuation allowance (see Note 5) also include significant estimates which, in the near term, could materially differ from the amounts ultimately realized or incurred.

Cash Equivalents

Cash equivalents include cash on hand, amounts held in banks, money market funds and other highly liquid investments with a maturity of three months or less at date of purchase.

Concentration of Credit Risk

Financial instruments, which potentially subject Gothic to concentrations of credit risk consist principally of derivative contracts (see "Hedging Activities" below), cash, cash equivalents and trade receivables. Gothic's accounts receivable are primarily from the purchasers (See Note 8 — Major Customers) of natural gas and oil products and exploration and production companies which own interests in properties operated by Gothic. The industry concentration has the potential to impact Gothic's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Gothic generally does not require collateral from customers. Gothic had an account receivable from one customer (CMS Continental Natural Gas) of approximately $2.3 million at December 31, 1999 and $8.8 million at December 31, 2000. The cash and cash equivalents are with major banks or institutions with high credit ratings. At December 31, 1999 and 2000, Gothic had a concentration of cash of $5.8 million and $6.5 million, respectively, with one bank, which was in excess of federally insured limits.

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." Gothic, using available market information, has determined the estimated fair value amounts. 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. Gothic estimates the fair value of Gothic Production's 11⅛% Senior Secured Notes and Gothic Energy's 14⅛% Senior Secured Discount Notes using estimated market prices. Gothic's carrying amount for such debt at December 31, 1999 was $235.0 million and $75.9 million, respectively, compared to approximate fair value of $197.4 million and $35.9 million, respectively. At December 31, 2000, the notes were carried at $235.0 million and $86.7 million, respectively, compared to an approximate fair value of $249.1 million and $80.1 million, respectively. The carrying value of other long-term debt approximates its fair value as interest rates are primarily variable, based on prevailing market rates.

Hedging Activities

Gothic has involvement with derivative financial instruments, as defined in Statement of Financial Accounting Standards No. 119 "Disclosure About Derivative Financial Instruments and Fair Value of Financial Instruments," and does not use them for trading purposes. Gothic's objective is to hedge a portion of its exposure to price volatility from producing natural gas. These arrangements may expose Gothic to credit risk from its counterparty.

In July 1999, Gothic entered into a costless collar agreement with respect to the production of 50,000 mmbtu per day during the period of November 1999 through March 2000, which placed a floor of $2.30 per mmbtu and a ceiling of $3.03 per mmbtu. Collar arrangements limit the benefits Gothic will realize if actual prices rise above the ceiling price. These arrangements provide for Gothic to exchange a floating market price for a fixed range contract price. Payments are made by Gothic when the floating price exceeds the fixed range for a contract month and payments are received when the fixed range price exceeds the floating price. The commodity reference price for the contract was the Panhandle Eastern Pipeline Company, Texas, and Oklahoma Mainline Index. In August 1999, Gothic entered into a hedge agreement covering 10,000 barrels of oil per month at a price of $20.10 per barrel. This hedge was in effect from September 1999 through August 2000.

Additionally, in January 2000, Gothic entered into a hedge agreement covering 50,000 mmbtu per day at a fixed price of $2.435 per mmbtu. This hedge was in effect from April 2000 through October 2000. In February 2000, Gothic entered into a hedge agreement covering 20,000 mmbtu per day at a fixed price of $2.535 per mmbtu for April 2000 and $2.555 per mmbtu for May 2000. This hedge was in effect for the months of April and May 2000. The commodity price for both contracts was the Panhandle Eastern Pipeline Company, Texas, Oklahoma Mainline Index.

In September 2000, Gothic entered into hedge contracts for the months of November and December 2000, for 60,000 mmbtu per day at a price of $4.88 and $5.00, respectively. The commodity price for both contracts was the Panhandle Eastern Pipeline Company, Texas, Oklahoma Mainline Index.

Gains and losses on such natural gas and oil hedging contracts are reflected in revenues when the natural gas or crude oil is sold. Hedging activities reduced 2000 realized prices by $0.65 per mcf and $5.79 per barrel, and reduced natural gas and oil sales by $17.9 million. Gothic had no open commodity hedges at December 31, 2000. If the open commodity hedges outstanding at December 31, 1999 had been settled at that date, Gothic would have realized a gain of approximately $500,000.

Natural Gas and Oil Properties

Gothic accounts for its natural gas and oil exploration and development activities using the full-cost method of accounting prescribed by the Securities and Exchange Commission ("SEC"). Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of natural gas and oil reserves are capitalized and depleted using the units-of-production method based on proved natural gas and oil reserves. Gothic capitalizes costs, including salaries and related fringe benefits of employees and/or consultants directly engaged in the acquisition, exploration and development of natural gas and oil properties, as well as other directly identifiable general and administrative costs associated with such activities. Such costs do not include any costs related to production, general corporate overhead, or similar activities.

Gothic's natural gas and oil reserves are estimated annually by independent petroleum engineers. Gothic's calculation of depreciation, depletion and amortization ("DD&A") includes estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of salvage values. The average composite rate used for DD&A of natural gas and oil properties was $0.91, $0.77 and $0.81 per mcfe in 1998, 1999 and 2000, respectively. DD&A of natural gas and oil properties amounted to $23.6 million, $20.4 million and $21.9 million in 1998, 1999 and 2000, respectively.

In the event the unamortized cost of natural gas and oil properties being amortized exceeds the full-cost ceiling as defined by the SEC, the excess is charged to expense in the period during which such excess occurs. The full-cost ceiling is based principally on the estimated future discounted net cash flows from Gothic's natural gas and oil properties. Gothic recorded a $76.0 million provision for impairment of natural gas and oil properties during the year ended December 31, 1998. No such provision was recorded in 1999 or 2000. As discussed in Note 11, estimates of natural gas and oil reserves are imprecise. Changes in the estimates or declines in natural gas and oil prices could cause Gothic in the near-term to reduce the carrying value of its natural gas and oil properties.

Sales and abandonments of properties are accounted for as adjustments of capitalized costs with no gain or loss recognized unless a significant amount of reserves is involved. Since all of Gothic's natural gas and oil properties are located in the United States, a single cost center is used.

Equipment, Furniture and Fixtures

Equipment, furniture and fixtures are stated at cost and are depreciated on the straight-line method over their estimated useful lives which range from three to seven years.

Debt Issuance Costs

Debt issuance costs, including the original issue discount associated with Gothic's 11⅛% Senior Secured Notes Due 2005 and Gothic Energy's 14⅛% Senior Secured Discount Notes Due 2006, are amortized and included in interest expense using the effective interest method over the term of the notes. The unamortized portion of debt issuance costs associated with Gothic's credit facility is also included in other assets and amortized and included in interest expense using the straight-line method over the term of the facility. Amortization of debt issuance costs for the years ended December 31, 1998, 1999 and 2000 amounted to $2.0 million, $1.8 million and $1.8 million, respectively. Unamortized debt issue costs at December 31, 1999 and 2000 were $9.9 million and $7.4 million, respectively.

Natural Gas and Oil Sales and Natural Gas Balancing

Gothic uses the sales method for recording natural gas sales. Gothic's oil and condensate production is sold, the title passes, and revenue is recognized at or near its wells under short-term purchase contracts at prevailing prices in accordance with arrangements which are customary in the oil industry. Sales of gas applicable to Gothic's interest in producing natural gas and oil leases are recorded as revenues when the gas is metered and title transferred pursuant to the gas sales contracts covering its interest in gas reserves. During such times as Gothic's sales of gas exceed its pro rata ownership in a well, such sales are recorded as revenues unless total sales from the well have exceeded Gothic's share of estimated total gas reserves underlying the property at which time such excess is recorded as a gas imbalance liability. At December 31, 1999, total sales exceeded Gothic's share of estimated total gas reserves on 32 wells by $2.8 million (1,449 mmcf), based on historical settlement prices. At December 31, 2000, total sales exceeded Gothic's share of estimated total gas reserves on 27 wells by $2.2 million (1,233 mmcf). The gas imbalance liability has been classified in the balance sheet as non-current, as Gothic does not expect to settle the liability during the next twelve months.

Gothic has recorded deferred charges for estimated lease operating expenses incurred in connection with its underproduced gas imbalance position. Cumulative total gas sales volumes for underproduced wells were less than Gothic's pro-rata share of total gas production from these wells by 4,435 mmcf and 4,122 mmcf for 1999 and 2000, respectively, resulting in prepaid lease operating expenses of $1.5 million and $1.2 million for 1999 and 2000, respectively, which are included in other assets in the accompanying balance sheet. The rate used to calculate the deferred charge is the average annual production costs per mcf.

Gothic has recorded accrued charges for estimated lease operating expenses incurred in connection with its overproduced gas imbalance position. Cumulative total gas sales volumes for overproduced wells exceeded Gothic's pro-rata share of total gas production from these wells by 2,717 mmcf and 2,271 mmcf for 1999 and 2000, respectively, resulting in accrued lease operating expenses of $897,000 and $681,000 in 1999 and 2000, respectively, which are included in the gas imbalance liability in the accompanying balance sheet. The rate used to calculate the accrued liability is the average annual production costs per mcf.

Income Taxes

Gothic applies the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" ("SFAS No. 109"). Under SFAS No. 109, deferred tax liabilities or assets arise from the temporary differences between the tax basis of assets and liabilities, and their basis for financial reporting, and are subject to tests of realizability in the case of deferred tax assets. A valuation allowance is provided for deferred tax assets to the extent realization is not judged to be more likely than not.

Loss per Common Share

Loss per common share before extraordinary item and net loss per common share are computed in accordance with Statement of Financial Accounting Standards No. 128 ("FAS 128"). Presented on the Consolidated Statement of Operations is a reconciliation of loss available to common shareholders. There is no difference between actual weighted average shares outstanding, which are used in computing basic loss per share, and diluted weighted average shares, which are used in computing diluted loss per share, because the effect of outstanding options and warrants would be antidilutive. Warrants and options to purchase approximately 20,775,000, 19,940,000 and 14,731,000 shares were outstanding as of December 31, 1998, 1999 and 2000, and were excluded from the computation of diluted loss per share due to their anti-dilutive impact.

Stock Based Compensation

Gothic applies Accounting Principles Board Opinion No. 25 in accounting for its stock option plans. Under this standard, no compensation expense is recognized for grants of options which include an exercise price equal to or greater than the market price of the stock on the date of grant. Accordingly, based on Gothic's grants in 1998 and 1999 no compensation expense has been recognized.

Recently Issued Financial Accounting Pronouncements

In June 1998, the FASB issued Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities". FAS 133, as amended, is effective for all fiscal quarters of fiscal years beginning after June 15, 2000 (January 1, 2001 for Gothic). FAS 133 standardizes the accounting for derivative instruments by requiring that all derivatives be recognized as assets and liabilities and measured at fair value. Upon the Statement's initial application, all derivatives are required to be recognized in the statement of financial position as either assets or liabilities and measured at fair value. In addition, all existing hedging relationships must be designated, reassessed, documented and the accounting conformed to the provisions of FAS 133. Gothic had no derivative instruments outstanding at December 31, 2000, and has not subsequently entered into any hedging instruments.

2. Financing Activities

Credit Facility

On April 27, 1998, Gothic Production, with Gothic Energy as guarantor, entered into a credit facility, with Bank One (the "Credit Facility"). The Credit Facility consists of a revolving line of credit, with an initial borrowing base of $25.0 million. Borrowings are limited to being available for the acquisition and development of natural gas and oil properties, letters of credit and general corporate purposes. The borrowing base will be redetermined at least semi-annually. Upon an amendment to the Credit Facility dated November 15, 2000, the borrowing base was reduced to $10.75 million and the principal is due at maturity, January 31, 2001. Interest is payable monthly calculated at the Bank One base rate, as determined from time to time by Bank One. Gothic may elect to calculate interest under a London Interbank Offered Rate ("LIBOR") plus 1.5% (or up to 2.0% in the event the loan balance is greater than 75% of the borrowing base). Gothic is required to pay a commitment fee on the unused portion of the borrowing base equal to ½ of 1% per annum. Under the Credit Facility, Bank One holds first priority liens on substantially all of the natural gas and oil properties of Gothic, whether currently owned or hereafter acquired. As of December 31, 2000 there were no borrowings outstanding under the Credit Facility. The Credit Facility was terminated on January 31, 2001.

11⅛% Senior Secured Notes Due 2005

The 11⅛% Senior Secured Notes Due 2005 ("Senior Secured Notes") issued by Gothic Production are fully and unconditionally guaranteed by Gothic Energy. The aggregate original principal amount of Senior Secured Notes outstanding was $235.0 million issued under an indenture dated April 21, 1998 (the "Senior Note Indenture"). The Senior Secured Notes bear interest at 11⅛% per annum payable semi-annually in cash in arrears on May 1 and November 1 of each year commencing November 1, 1998. The Senior Secured Notes mature on May 1, 2005. All of the obligations of Gothic Production under the Senior Secured Notes are collateralized by a second priority lien on substantially all of Gothic's natural gas and oil properties, subject to certain permitted liens.

Gothic may, at its option, at any time on or after May 1, 2002, redeem all or any portion of the Senior Secured Notes at redemption prices decreasing from 105.563%, if redeemed in the 12-month period beginning May 1, 2002, to 100.00% if redeemed in the 12-month period beginning May 1, 2004 and thereafter plus, in each case, accrued and unpaid interest thereon. Notwithstanding the foregoing, at any time prior to May 1, 2002, Gothic may, at its option, redeem all or any portion of the Senior Secured Notes at the Make-Whole Price (as defined in the Senior Note Indenture) plus accrued or unpaid interest to the date of redemption. In addition, in the event Gothic consummates one or more Equity Offerings (as defined in the Senior Note Indenture) on or prior to May 1, 2001, Gothic, at its option, may redeem up to 33⅓% of the aggregate principal amount of the Senior Secured Notes with all or a portion of the aggregate net proceeds received by Gothic from such Equity Offering or Equity Offerings at a redemption price of 111.125% of the aggregate principal amount of the Senior Secured Notes so redeemed, plus accrued and unpaid interest thereon to the redemption date; provided, however, that following such redemption, at least 66⅔% of the original aggregate principal amount of the Senior Secured Notes remains outstanding.

Following the occurrence of any Change of Control (as defined in the Senior Note Indenture), Gothic must offer to repurchase all outstanding Senior Secured Notes at a purchase price equal to 101% of the aggregate principal amount of the Senior Secured Notes, plus accrued and unpaid interest to the date of repurchase. Gothic made a Change of Control offer following the Chesapeake Merger. The offer terminated on February 22, 2001. Prior to the expiration of the offer, $1.0 million of the Senior Secured Notes were tendered and purchased by Gothic.

The Senior Note Indenture under which the Senior Secured Notes were issued contains certain covenants limiting Gothic with respect to or imposing restrictions on the incurrence of additional indebtedness, the payment of dividends, distributions and other restricted payments, including the payment of dividends and distributions to Gothic Energy and Chesapeake, the sale of assets, creating, assuming or permitting to exist any liens (with certain exceptions) on its assets, mergers and consolidations (subject to meeting certain conditions), sale leaseback transactions, and transactions with affiliates, among other covenants.

Events of default under the Senior Note Indenture include the failure to pay any payment of principal or premium when due, failure to pay for 30 days any payment of interest when due, failure to make any optional redemption payment when due, failure to perform any covenants relating to mergers or consolidations, failure to perform any other covenant or agreement not remedied within 30 days of notice from the Trustee under the Senior Note Indenture or the holders of 25% in principal amount of the Senior Secured Notes then outstanding, defaults under other indebtedness of Gothic causing the acceleration of the due date of such indebtedness having an outstanding principal amount of $10.0 million or more, the failure of Gothic Production to be a wholly owned subsidiary of Gothic Energy, and certain other bankruptcy and other court proceedings, among other matters.

14⅛% Senior Secured Discount Notes Due 2006

The 14⅛% Senior Secured Discount Notes Due 2006 (the "Discount Notes") were issued by Gothic Energy under an indenture (the "Discount Note Indenture") dated April 21, 1998 in such aggregate principal amount and at such rate of interest as generated gross proceeds of $60.2 million. Gothic also issued seven-year warrants to purchase, at an exercise price of $2.40 per share, 825,000 shares of Gothic Energy's common stock with the Discount Notes. The estimated fair value of such warrants was approximately $554,000 on the date of issuance. The Discount Notes were issued at a substantial discount from their principal amount and accrete at a rate per annum of 14⅛%, compounded semi-annually, to an aggregate principal amount of $104.0 million at May 1, 2002. Thereafter, the Discount Notes accrue interest at the rate of 14⅛% per annum, payable in cash semi-annually in arrears on May 1 and November 1 of each year, commencing November 1, 2002. The Discount Notes mature on May 1, 2006 and are collateralized by a first priority lien against the outstanding shares of capital stock of Gothic Production. The carrying amount of the Discount Notes as of December 31, 2000 was $86.7 million.

Gothic may, at its option, at any time on or after May 1, 2003, redeem all or any portion of the Discount Notes at redemption prices decreasing from 107.063% if redeemed in the 12-month period beginning May 1, 2003 to 100.00% if redeemed in the 12-month period beginning May 1, 2005 and thereafter plus, in each case, accrued and unpaid interest thereon. Notwithstanding the foregoing, at any time prior to May 1, 2003, Gothic may, at its option, redeem all or any portion of the Discount Notes at the Make-Whole Price (as defined in the Discount Note Indenture) plus accrued or unpaid interest to the date of redemption.

3. Stockholders' Equity

In January 1999, Gothic Energy issued 30,000 shares of its common stock as part of a severance package to a former employee. On August 17, 1999, Chesapeake fully exercised the common stock purchase warrant issued to it in April 1998 and purchased 2,394,125 shares of Gothic Energy's common stock. The warrant had been issued to Chesapeake as part of the transaction involving the sale to Chesapeake of shares of Gothic Energy's Series B Senior Redeemable Preferred Stock, a 50% interest in Gothic's Arkoma basin natural gas and oil properties and a 50% interest in substantially all of Gothic's undeveloped acreage. The shares were issued pursuant to the cashless exercise provisions of the warrant that permitted Chesapeake to surrender the right to exercise the warrant for a number of shares of Gothic Energy's common stock having a market value equivalent to the total exercise price. The total exercise price was $23,941.25 or $0.01 per share. An aggregate of 45,121 warrants were surrendered in payment of the total exercise price. The shares of common stock were issued pursuant to the exemption from the registration requirements of the Securities Act of 1933, as amended, afforded by section 4(2) thereof.

In July 2000, Gothic Energy issued 225,000 shares of its common stock to one director and certain employees upon their exercise of stock options.

In July 2000, Gothic Energy issued 233,000 shares of its common stock to two warrant holders upon the exercise of outstanding common stock purchase warrants.

In August 2000, Gothic Energy issued 4,161,000 shares of its common stock to certain employees, two officers and two directors, upon their exercise of stock options. The directors, officers and employees issued full recourse interest bearing promissory notes, due one year from the date of issuance, upon exercise of the stock options. All of these notes were paid in full prior to January 31, 2001.

Preferred Stock

On April 27, 1998, as part of a recapitalization, Gothic Energy issued 50,000 shares of Series B Preferred Stock with an aggregate liquidation preference of $50.0 million and a warrant to purchase 2,439,246 shares of Gothic Energy's common stock, discussed above. The estimated fair value of such warrant was $4.9 million on the date of issuance. The Series B Preferred Stock, with respect to dividend rights and rights on liquidation, winding-up and dissolution, ranks senior to all classes of common stock of Gothic Energy and senior to all other classes or series of any class of preferred stock. Holders of the Series B Preferred Stock are entitled to receive dividends payable at a rate per annum of 12% of the aggregate liquidation preference of the Series B Preferred Stock payable in additional shares of Series B Preferred Stock; provided that after April 1, 2000, at Gothic Energy's option, it may pay the dividends in cash. Dividends are cumulative and will accrue from the date of issuance and are payable quarterly in arrears.

At any time prior to April 30, 2000, the Series B Preferred Stock may have been redeemed at the option of Gothic Energy in whole or in part, at 105% of the liquidation preference payable in cash out of the net proceeds from a public or private offering of any equity security, plus accrued and unpaid dividends (whether or not declared), which shall also be paid in cash. At any time on or after April 30, 2000, the Series B Preferred Stock may have been redeemed at the option of Gothic Energy in whole or in part, in cash at a redemption price equal to the liquidation preference.

Gothic Energy is required to redeem the Series B Preferred Stock on June 30, 2008 at a redemption price equal to the liquidation preference payable in cash or, at the option of Gothic Energy, in shares of common stock valued at the fair market value at the date of such redemption.

Except as required by Oklahoma law, the holders of Series B Preferred Stock are not entitled to vote on any matters submitted to a vote of the stockholders of Gothic Energy.

The Series B Preferred Stock is convertible at the option of the holders on or after April 30, 2000 into the number of fully paid and non-assessable shares of common stock determined by dividing the liquidation preference by the higher of (i) $2.04167 or (ii) the fair market value on the date the Series B Preferred Stock is converted. Notwithstanding the foregoing, no holder or group shall be able to convert any shares of Series B Preferred Stock to the extent that the conversion of such shares would cause such holder or group to own more than 19.9% of the outstanding common stock of Gothic Energy.

The Series B Preferred Stock, all of which was owned by Chesapeake prior to the Merger, remains outstanding. As part of the Merger, the terms of the Series B Preferred Stock were amended to provide for noncumulative cash dividends of $80 per share per annum if, as and when declared by the Board of Directors, optional redemption rights permitting Gothic Energy to redeem the shares at any time or from time to time, and mandatory redemption for cash on June 30, 2008. The amendment also eliminated conversion rights.

Other Warrants

In connection with past financing arrangements and as compensation for consulting and professional services, Gothic Energy has issued other warrants to purchase its common stock.

A summary of the status of Gothic Energy's warrants as of December 31, 1997, 1998, 1999 and 2000, and changes during the years ended December 31, 1998, 1999 and 2000 is presented below:

	Number Outstanding	Weighted Average Price	Number Exercisable	Weighted Average Exercise Price
Balance at December 31, 1997	11,404,531	$2.54	11,404,531	$2.54
Warrants granted	5,940,024	1.06		
Balance at December 31, 1998	17,344,555	$2.00	17,344,555	$2.00
Warrants exercised/expired	(2,639,246)	0.20		
Balance at December 31, 1999	14,705,309	$2.33	14,705,309	$2.33
Warrants exercised/expired	(1,233,121)	2.20		
Warrants adjusted for antidilution	524,109	—		
Balance at December 31, 2000	13,996,297	$2.40	13,996,297	$2.40

The following table summarizes information about Gothic Energy's warrants, which were outstanding, and those which were exercisable, as of December 31, 2000:

	Warrants Outstanding			Warrants Exercisable	
Price Range	Number Outstanding	Weighted Average Life	Weighted Average Price	Number Exercisable	Weighted Average Price
$1.78 — $3.00	13,996,297	1.1 years	$2.40	13,996,297	$2.40

4. Stock Options

Incentive Stock Option Plan

Gothic Energy has an incentive stock option and non-statutory option plan, which provides for the issuance of options to purchase up to 2,500,000 shares of common stock to key employees and directors. The incentive stock options granted under the Plan are generally exercisable for a period of ten years from the date of the grant, except that the term of an incentive stock option granted under the Plan to a stockholder owning more than 10% of the outstanding common stock must not exceed five years and the exercise price of an incentive stock option granted to such a stockholder must not be less than 110% of the fair market value of the common stock on the date of grant. The exercise price of a non-qualified option granted under the Plan may not be less than 40% of the fair market value of the common stock at the time the option is granted. No non-qualified options have been issued under the Plan. As of December 31, 1998 and 1999, options to purchase 2,095,000 and 2,500,000 shares of common stock, respectively, had been issued under the Plan. As of December 31, 2000, all options granted under the Plan had been exercised.

Omnibus Incentive Plan

On August 13, 1996 at the annual shareholders' meeting, the shareholders approved the 1996 Omnibus Incentive Plan and the 1996 Non-Employee Stock Option Plan. The 1996 Omnibus Incentive Plan provides for compensatory awards of up to an aggregate of 1,000,000 shares of common stock of Gothic Energy to officers, directors and certain other key employees. Awards may be granted for no consideration and consist of stock options, stock awards, stock appreciation rights, dividend equivalents, other stock-based awards (such as phantom stock) and performance awards consisting of any combination of the foregoing. Generally, options will be granted at an exercise price equal to the lower of (i) 100% of the fair market value of the shares of common stock on the date of grant or (ii) 85% of the fair market value of the shares of common stock on the date of exercise. Each option will be exercisable for the period or periods specified in the option agreement, which will generally not exceed 10 years from the date of grant. As of December 31, 1999, options to purchase 1,000,000 shares of common stock had been issued under the Omnibus Incentive Plan. As of December 31, 2000, all options granted under the Omnibus Incentive Plan had been exercised.

Non-Employee Stock Option Plan

The 1996 Non-Employee Stock Option Plan provides a means by which non-employee directors of Gothic and consultants to Gothic can be given an opportunity to purchase stock in Gothic Energy. The plan provides that a total of 1,000,000 shares of Gothic Energy's common stock may be issued pursuant to options granted under the Non-Employee Plan, subject to certain adjustments. The exercise price for each option granted under the Non-Employee Plan will not be less than the fair market value of the common stock on the date of grant. Each option will be exercisable for the period or periods specified in the option agreement, which can not exceed 10 years from the date of grant. Options granted to directors will terminate thirty (30) days after the date the director is no longer a director of Gothic. As of December 31, 1998 and 1999, options to purchase 600,000 and 1,000,000 shares of common stock, respectively, had been issued under the Non-Employee Plan. As of December 31, 2000, all options granted under the Non-Employee Plan had been exercised.

A summary of the status of Gothic Energy's stock options as of December 31, 1997, 1998, 1999 and 2000, and changes during December 31, 1998, 1999 and 2000, is presented below:

	Options Outstanding		Options Exercisable	
	Number Outstanding	Weighted Average Price	Number Exercisable	Weighted Average Price
Balance at December 31, 1997	2,690,000	$ 1.17	1,850,000	$1.52
Options granted	1,285,000	.40		
Options forfeited	(545,000)	.40		
Balance at December 31, 1998	3,430,000	$ 1.00	1,927,500	$1.47
Options granted	2,185,000	.39		
Options forfeited	(380,000)	.40		
Balance at December 31, 1999	5,235,000	$ .79	2,807,500	$1.13
Options exercised	(4,390,000)	.15-.53		
Options forfeited	(110,000)	.40		
Balance at December 31, 2000	735,000	$ 3.21	735,000	$3.21

The following table summarizes information about Gothic Energy's stock options which were outstanding, and those which were exercisable, as of December 31, 2000:

	Options Outstanding			Options Exercisable	
Price Range	Number Outstanding	Weighted Average Life	Weighted Average Price	Number Exercisable	Weighted Average Price
$1.50 — $3.30	735,000	0.3 years	$3.21	735,000	$3.21

Gothic applies Accounting Principles Board Opinion No. 25 in accounting for stock options granted to employees, including directors, and Statement of Financial Accounting Standards No. 123 ("SFAS No. 123") for stock options and warrants granted to non-employees. No compensation cost has been recognized in 1998, 1999 or 2000.

Had compensation been determined on the basis of fair value pursuant to SFAS No. 123, net loss and loss per share would have been increased as follows:

	1998	1999	2000
	($ in thousands, except per share data)		
Net loss available for common shares:			
As reported	$(140,383)	$(25,976)	$(3,445)
Pro forma	$(141,232)	$(26,439)	$(3,751)
Basic and diluted loss per share:			
As reported	$ (8.63)	$ (1.51)	$ (0.17)
Pro forma	$ (8.68)	$ (1.54)	$ (0.18)

The fair value of each option granted is estimated using the Black Scholes model. Gothic's stock volatility was 0.81 and 0.95 in 1998 and 1999, respectively, based on previous stock performance. Dividend yield was estimated to remain at zero with an average risk-free interest rate of 4.81 percent and 5.59 percent in 1998 and 1999, respectively. Expected life was three years for options issued in both 1998 and 1999 based on the vesting periods involved and the make up of participating employees within each grant. Fair value of options granted during 1998 and 1999 under the Stock Option Plan were $643,000 and $646,000, respectively. No options were granted during 2000. As part of the Merger, all plans terminated on January 16, 2001.

5. Income Taxes

A reconciliation of the income tax expense or benefit, computed by applying the federal statutory rate to pre-tax income or loss, to Gothic's effective income tax expense or benefit is as follows:

	1998	1999	2000
	($ in thousands)		
Income tax (expense) benefit computed at the statutory rate (34%)	$ 44,094	$ 5,885	$(2,068)
State income taxes, net of federal	5,135	685	(260)
Change in valuation allowance	(49,229)	(6,570)	2,555
Other	—	—	(227)
Income tax (expense) benefit	—	—	—

Deferred tax assets and liabilities are comprised of the following at December 31, 1999 and 2000:

	1999	2000
	($ in thousands)	
Deferred tax assets:		
Gas balancing liability	$ 1,386	$ 1,077
Net operating loss carryforwards	68,448	68,436
Depletion carryforwards	257	257
Tax over book basis of property and equipment	2,627	426
Accrued wages	119	—
Gross deferred tax assets	72,837	70,196
Deferred tax liabilities:		
Deferred lease operating expenses	(556)	(470)
Gross deferred tax liabilities	(556)	(470)
Net deferred tax assets	72,281	69,726
Valuation allowance	(72,281)	(69,726)
	—	—

Net operating losses of approximately $180.3 million are available for future use against taxable income. These net operating loss carryforwards ("NOL") expire in the years 2010 through 2019.

Pursuant to Section 382 of the Internal Revenue Code of 1986, as amended, in the event that a substantial change in the ownership of Gothic Energy were to occur in the future (whether through the sale of stock by a significant shareholder or shareholders, new issuances of stock by Gothic Energy, conversions, a redemption, recapitalization, reorganization, any combination of the foregoing or any other method) so that ownership of more than 50% of the value of Gothic Energy's capital stock changed during any three-year period, Gothic Energy's ability to utilize its NOLs could be substantially limited.

Realization of the net deferred tax asset is dependent on generating sufficient taxable income in future periods. As a result of significant losses in prior years, Gothic has recorded a 100% valuation allowance, as management presently deems it is more likely than not that realization will not occur in the future.

6. Commitments and Contingencies

Gothic entered into an employment agreement with its President effective January 1, 1999. The President received a base salary of $225,000 per year. In addition, he was to receive a cash bonus as was determined by Gothic's Board of Directors. The President was also entitled to participate in such incentive compensation and benefit programs as Gothic made available. The term of the agreement was for a period of three years and at the end of the first year and at the end of each succeeding year the agreement was automatically extended for one year such that at the end of each year there would automatically be three years remaining on the term of the agreement. The President could terminate the agreement at the end of the initial term and any succeeding term on not less than six months notice. In the event the employment agreement was terminated by Gothic (other than for cause, as defined), the President was entitled to receive a payment representing all salary due under the remaining full term of his agreement and Gothic was obligated to continue his medical insurance and other benefits provided under the agreement in effect for a period of one year after such termination. In the event of a change in control, as defined, of Gothic, the President had the right to terminate his employment agreement with Gothic within sixty days thereafter, whereupon Gothic would be obligated to pay to him a sum equal to three years of his base salary under the agreement, plus a lump sum payment of $250,000. The President resigned from Gothic effective January 16, 2001, upon completion of the Chesapeake Merger.

Gothic also entered into an employment agreement with its Chief Financial Officer effective January 1, 1999. The Chief Financial Officer received a base salary of $187,500 per year. In addition, he was to receive a cash bonus as was determined by Gothic's Board of Directors. The CFO was also entitled to participate in such incentive compensation and benefit programs as Gothic made available. The term of the agreement was for a period of three years and at the end of the first year and at the end of each succeeding year the agreement was automatically extended for one year such that at the end of each year there would automatically be three years remaining on the term of the agreement. The CFO could terminate the agreement at the end of the initial term and any succeeding term on not less than six months notice. In the event the employment agreement was terminated by Gothic (other than for cause, as defined), the CFO was entitled to receive a payment representing all salary due under the remaining full term of his agreement, and Gothic was obligated to continue his medical insurance and other benefits provided under the agreement in effect for a period of one year after such termination. In the event of a change in control, as defined, of Gothic, the CFO had the right to terminate his employment with Gothic within sixty days thereafter, whereupon Gothic would be obligated to pay to him a sum equal to three years base salary, plus a lump sum payment of $200,000. The Chief Financial Officer resigned from Gothic effective January 16, 2001, upon completion of the Chesapeake Merger.

The above employment agreements were amended in connection with the Merger whereby the executives each received a severance payment equal to their year 2000 base salary, and entered into consulting and non-compete agreements with Chesapeake.

Gothic leases its corporate offices and certain office equipment and automobiles under non-cancelable operating leases. Rental expense under non-cancelable operating leases was $190,000, $240,000 and $345,000 for the years ended December 31, 1998, 1999 and 2000, respectively.

Remaining minimum annual rentals under non-cancelable lease agreements subsequent to December 31, 2000 are as follows:

2001	$295,000
2002	$282,000
2003	$267,000
2004	$247,000

Gothic is not a defendant in any pending legal proceedings other than routine litigation incidental to its business. While the ultimate results of these proceedings cannot be predicted with certainty, Gothic does not believe that the outcome of these matters will have a material adverse effect on Gothic's financial position or results of operations.

7. Benefit Plan

Gothic maintained a 401(k) plan for the benefit of its employees. The plan was implemented in October 1997. The plan permitted employees to make contributions on a pre-tax salary reduction basis. Gothic made limited matching contributions to the plan, and also made other discretionary contributions. Gothic's contributions for 1998, 1999 and 2000 were $62,000, $85,000 and $81,000, respectively. The plan was terminated in December 2000.

8. Major Customers

During the year ended December 31, 2000, Gothic was a party to contracts whereby it sold approximately 60% of its natural gas production to CMS Continental Natural Gas Corporation ("Continental"), and approximately 64% of its oil production to Duke Energy, Inc. Gothic has a ten-year marketing agreement, whereby the majority of the natural gas associated with properties acquired from Amoco in January 1998 will be sold to Continental, at market prices, under this agreement.

9. Related Party Transactions

During 1997, Gothic made advances totaling $336,000 to two officers and directors of Gothic. In February 1998, $168,000 was received in connection with a severance agreement. The balance outstanding on the remaining advance was $179,000 as of December 31, 1998. This amount was forgiven by Gothic during 1999.

During 2000, Gothic made advances to directors, officers and employees totaling $1.7 million for the exercise of options to purchase Gothic common stock. These amounts were settled in connection with the Merger on January 16, 2001.

10. Selected Quarterly Financial Information (Unaudited)

Summarized quarterly financial information for 1999 and 2000 is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	($ in thousands, except per share data)			
Year Ended December 31, 1999:				
Revenues	$11,470	$13,206	$14,150	$16,798
Gross profit(1)	$ 3,846	$ 5,577	$ 6,217	$ 9,410
Net loss	$(5,621)	$(4,850)	$(4,296)	$(2,542)
Loss per common share:(2)				
Basic	$ (0.47)	$ (0.43)	$ (0.37)	$ (0.26)
Diluted	$ (0.47)	$ (0.43)	$ (0.37)	$ (0.26)
Year Ended December 31, 2000:				
Revenues	$15,559	$17,660	$21,904	$30,622
Gross profit(1)	$ 8,334	$10,467	$12,920	$19,603
Net income (loss)	$(2,883)	$ (517)	$ 1,325	$ 8,157
Earnings (loss) per common share:(2)				
Basic	$ (0.28)	$ (0.15)	$ (0.05)	$ 0.24
Diluted	$ (0.28)	$ (0.15)	$ (0.05)	$ 0.24

(1) Gross profit includes total revenues, less lease operating expenses and depletion, depreciation and amortization expense.

(2) As a result of shares issued during the year, earnings per share for the year's four quarters, which is based on average shares outstanding during each quarter, does not equal the annual earnings per share, which is based on the average shares outstanding during the year.

11. Supplementary Natural Gas and Oil Information

The following supplemental historical and reserve information is presented in accordance with Financial Accounting Standards Board Statement No. 69, "Disclosures About Oil and Gas Producing Activities".

Financial Data

Capitalized Costs

The aggregate amounts of capitalized costs relating to natural gas and oil producing activities, net of valuation allowances, and the aggregate amounts of the related accumulated depreciation, depletion, and amortization at December 31, 1999 and 2000 were as follows:

	1999	2000
	($ in thousands)	
Proved properties	$258,818	$275,827
Unproved, not subject to depreciation, depletion and amortization	5,473	6,191
Less accumulated depreciation, depletion, and amortization	(53,137)	(75,003)
Net natural gas and oil properties	$211,154	$207,015

Costs Incurred

Costs incurred in natural gas and oil property acquisition, exploration and development activities for the years ended December 31, 1998, 1999 and 2000 were as follows:

	1998	1999	2000
	($ in thousands)		
Proved property acquisition	$225,103	$ 1,499	$ 655
Unproved property acquisition	2,109	2,611	718
Development costs	16,270	18,445	18,535
Total costs incurred	$243,482	$22,555	$19,908

Results of Operations From Oil and Gas Producing Activities (Unaudited)

Gothic's results of operations from natural gas and oil producing activities are presented below for 1998, 1999 and 2000. The following table includes revenues and expenses associated directly with Gothic's natural gas and oil producing activities.

	1998	1999	2000
	($ in thousands)		
Oil and gas sales	$ 50,714	$ 52,967	$ 83,065
Production expenses	(8,608)	(5,725)	(5,234)
Production taxes	(3,521)	(3,880)	(6,566)
Impairment of oil and gas properties	(76,000)	—	—
Depletion and depreciation	(24,001)	(20,969)	(22,621)
Results of operations from oil and gas producing activities	$(61,416)	$ 22,393	$ 48,644

Natural Gas and Oil Reserves Data (Unaudited)

Estimated Quantities

Natural gas and oil reserves cannot be measured exactly. Estimates of natural gas and oil reserves require extensive judgments of reservoir engineering data and are generally less precise than other estimates made in connection with financial disclosures.

Proved reserves are those quantities which, upon analysis of geological and engineering data, appear with reasonable certainty to be recoverable in the future from known natural gas and oil reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

Estimates of natural gas and oil reserves require extensive judgments of reservoir engineering data as explained above. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. Indeed, the uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. The information set forth herein is therefore subjective and, since judgments are involved, may not be comparable to estimates submitted by other natural gas and oil producers. In addition, since prices and costs do not remain static and no price or cost escalations or de-escalations have been considered, the results are not necessarily indicative of the estimated fair market value of estimated proved reserves nor of estimated future cash flows and significant revisions could occur in the near term. Accordingly, these estimates are expected to change as future information becomes available. All of Gothic's reserves are located onshore in the states of Oklahoma, Texas, New Mexico, Arkansas and Kansas.

The following unaudited table, which is based on reports of Lee Keeling and Associates, Inc., sets forth proved natural gas and oil reserves:

	1998		1999		2000	
	mbbls	mmcf	mbbls	mmcf	mbbls	mmcf
Proved Reserves:						
Beginning of year	3,585	127,460	1,761	306,668	1,922	289,191
Revisions of previous estimates	(872)	39,577	319	6,598	50	32,051
Purchases of reserves in place	1,362	233,007	—	1,402	—	172
Production	(257)	(24,455)	(158)	(25,477)	(135)	(26,309)
Sales of reserves in place	(2,057)	(68,921)	—	—	(69)	(4,198)
End of year	1,761	306,668	1,922	289,191	1,768	290,907
Proved Developed:						
Beginning of year	2,503	91,690	1,523	254,762	1,683	251,631
End of year	1,523	254,762	1,683	251,631	1,567	245,472

Standardized Measure of Discounted Future Net Cash Flows

Future net cash inflows are based on the future production of proved reserves of natural gas and crude oil as estimated by Lee Keeling and Associates, Inc., independent petroleum engineers, by applying current prices of natural gas and oil to estimated future production of proved reserves. The average prices used in determining future cash inflows for natural gas and oil as of December 31, 2000, were $10.19 per mcf, and $26.54 per barrel, respectively. These prices were based on the adjusted cash spot price for natural gas and oil at December 31, 2000. These prices are significantly higher than the average natural gas and oil price ($5.88 per mcf and $25.00 per barrel) received by Gothic during December 2000, and the prices Gothic expects to receive during 2001. Future net cash flows are then calculated by reducing such estimated cash inflows by the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves and by the estimated future income taxes.

Estimated future income taxes are computed by applying the appropriate year-end statutory tax rate to the future pretax net cash flows relating to Gothic's estimated proved natural gas and oil reserves. The estimated future income taxes give effect to permanent differences and tax credits and allowances.

Included in the estimated standardized measure of future cash flows are certain capital projects (future development costs). Gothic estimates the capital required to develop its undeveloped natural gas and oil reserves during 2001 to be approximately $30.0 million. If such capital is not employed, the estimated future cash flows will be negatively impacted.

The following table sets forth Gothic's unaudited estimated standardized measure of discounted future net cash flows.

	For the Years Ended December 31,		
	1998	1999	2000
	($ in thousands)		
Cash Flows Relating to Proved Reserves:			
Future cash inflows	$ 573,604	$ 596,216	$3,005,450
Future production costs	(141,253)	(139,458)	(350,371)
Future development costs	(37,028)	(26,969)	(42,260)
Future income tax expense	(47,264)	(30,113)	(843,629)
	348,059	399,676	1,769,190
Ten percent annual discount factor	(169,297)	(201,291)	(911,617)
Standardized measure of discounted future net cash flows	$ 178,762	$ 198,385	$ 857,573

The following table sets forth changes in the standardized measure of discounted future net cash flows:

	For the Years Ended December 31,		
	1998	1999	2000
	($ in thousands)		
Standardized measure of discounted future cash flows-beginning of period	$ 94,102	$178,762	$198,385
Sales of natural gas and oil produced, net of operating expenses	(38,585)	(43,362)	(71,265)
Purchases of reserves-in-place	231,184	1,000	114
Sales of reserves-in-place	(62,933)	—	(3,815)
Revisions of previous quantity estimates and changes in sales prices and production costs	(54,416)	44,109	714,315
Accretion of discount	9,410	17,876	19,839
Standardized measure of discounted future cash flows-end of period	$178,762	$198,385	$857,573

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, 2001.

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, 2001.

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

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, 2001.

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, 2001.

PART IV

ITEM 14. ***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, Gothic's consolidated financial statements and pro forma combined 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	—	Senior Secured Discount Notes Purchase Agreement dated June 23, 2000 between Chesapeake Energy Marketing, Inc. and Appaloosa Investment Limited Partnership I, Palomino Fund Ltd. and Tersk L.L.C. Incorporated herein by reference to Exhibit 2.1 to Registrant's Form S-1 Registration Statement (No. 333-41014).
2.2	—	Senior Secured Discount Notes Purchase Agreement dated June 23, 2000 between Chesapeake Energy Marketing, Inc. and Oppenheimer Strategic Income Fund, Oppenheimer Champion Income Fund, Oppenheimer High Yield Fund, Oppenheimer Strategic Bond Fund/VA and Atlas Strategic Income Fund. Incorporated herein by reference to Exhibit 2.2 to Registrant's Form S-1 Registration Statement (No. 333-41014).
2.3	—	Senior Secured Discount Notes Purchase Agreement dated June 26, 2000 between Chesapeake Energy Marketing, Inc. and John Hancock High Yield Bond Fund and John Hancock Variable Annuity High Yield Bond Fund. Incorporated herein by reference to Exhibit 2.3 to Registrant's Form S-1 Registration Statement (No. 333-41014).
2.4	—	Senior Secured Discount Notes Purchase Agreement dated June 26, 2000 between Chesapeake Energy Marketing, Inc. and Ingalls & Snyder Value Partners, L.P., Heritage Mark Foundation and Arthur R. Ablin. Incorporated herein by reference to Exhibit 2.4 to Registrant's Form S-1 Registration Statement (No. 333-41014).
2.5	—	Senior Secured Discount Notes Purchase Agreement dated August 29, 2000 between Chesapeake Energy Marketing, Inc. and BNP Paribas. Incorporated herein by reference to Exhibit 2.5 to Registrant's registration statement on Form S-1 (No. 333-45872).
2.6	—	Senior Secured Notes Purchase Agreement dated September 1, 2000 between Chesapeake Energy Corporation and Lehman Brothers Inc. Incorporated herein by reference to Exhibit 2.6 to Registrant's registration statement on Form S-1 (No. 333-45872).
2.7	—	Agreement and Plan of Merger dated September 8, 2000 among Chesapeake Energy Corporation, Chesapeake Merger 2000 Corp. and Gothic Energy Corporation, as amended by Amendment No. 1 to Agreement and Plan of Merger dated October 31, 2000. Incorporated by reference to Annex A to proxy statement/prospectus included in Amendment No. 1 to Registrant's registration statement on Form S-4 (No. 333-47330).
3.1	—	Registrant's Certificate of Incorporation as amended. Incorporated herein by reference to Exhibit 3.1 to Registrant's registration statement on Form S-1 (No. 333-45872).
3.2	—	Registrant's Bylaws. Incorporated herein by reference to Exhibit 3.2 to Registrant's registration statement on Form 8-B (No. 001-13726).

Exhibit Number		Description
4.1	—	Indenture dated as of March 15, 1997 among the Registrant, as issuer, Chesapeake Operating, Inc., Chesapeake Gas Development Corporation and Chesapeake Exploration Limited Partnership, as Subsidiary Guarantors, and 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 Registrant'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 Registrant'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 Registrant's Amendment No. 1 to Form S-3 registration statement (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.
4.2	—	Indenture dated as of March 15, 1997 among the Registrant, as issuer, Chesapeake Operating, Inc., Chesapeake Gas Development Corporation and Chesapeake Exploration Limited Partnership, as Subsidiary Guarantors, and 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 Registrant'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 Registrant'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 Registrant's Amendment No. 1 to Form S-3 registration statement (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.
4.3	—	Indenture dated as of April 1, 1998 among the Registrant, as Subsidiary Guarantors, and United States Trust Company of New York, As Trustee, with respect to 9.625% Senior Notes due 2005. Incorporated herein by reference to Exhibit 4.3 to Registrant registration statement on Form S-3 (No. 333-57235). First Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.4.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.
4.4	—	Indenture dated as of April 1, 1996 among the Registrant, its subsidiaries signatory thereto, as Subsidiary Guarantors, and United States Trust Company of New York, as Trustee, with respect to 9.125% Senior Notes, due 2006. Incorporated herein by reference to Exhibit 4.6 to Registrant's registration statement on Form S-3 (No. 333-1588). First Supplemental Indenture dated December 30, 1996 and Second Supplemental Indenture dated December 17, 1997. Incorporated herein by reference to Exhibit 4.4.1 to Registrant's transition report on Form 10-K for the six months ended December 31, 1997. Third Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.4.1 to Registrant's Amendment No. 1 to Form S-3 registration statement (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.3.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.
4.5	—	Agreement to furnish copies of unfiled long-term debt Instruments. Incorporated herein by reference to Registrant's transition report on Form 10-K for the six months ended December 31, 1997.
4.7	—	Common Stock Registration Rights Agreement dated as of June 27, 2000 among the Registrant and Appaloosa Investment Limited Partnership I, Palomino Fund Ltd., Tersk L.L.C., Oppenheimer Strategic Income Fund, Oppenheimer Champion Income Fund, Oppenheimer High Yield Fund, Oppenheimer Strategic Bond Fund/VA and Atlas Strategic Income Fund. Incorporated herein by reference to Exhibit 4.6 to Registrant's registration statement on Form S-1 (No. 333-41014).
4.8*	—	Warrant dated as of August 19, 1996 issued by Gothic Energy Corporation to Gaines, Berland Inc.
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.
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.

Exhibit Number		Description
4.11*	—	Warrant Agreement dated as of January 23, 1998 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent.
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.
4.13*	—	Substitute Warrant to Purchase Common Stock of Chesapeake Energy Corporation dated as of January 16, 2001 issued to Amoco Corporation.
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.
4.15*	—	Warrant Registration Rights Agreement dated as of April 21, 1998 among Gothic Energy Corporation and purchasers of units consisting of its 14⅛% senior secured discount notes due 2006 and warrants to purchase its common stock.
10.1.1†	—	Registrant's 1992 Incentive Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.1 to Registrant's registration statement on Form S-4 (No. 33-93718).
10.1.2†	—	Registrant's 1992 Nonstatutory Stock Option Plan, as Amended. Incorporated herein by reference to Exhibit 10.1.2 to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.3†	—	Registrant's 1994 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.3 to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.4†	—	Registrant's 1996 Stock Option Plan. Incorporated herein by reference to Registrant's Proxy Statement for its 1996 Annual Meeting of Shareholders and to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.5†	—	Registrant's 1999 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.5 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 1999.
10.1.6†	—	Registrant's 2000 Employee Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.6 to Registrant's quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.7†	—	Registrant's 2000 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.7 to Registrant's quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.2.1†	—	Amended and Restated Employment Agreement dated as of July 1, 1998, as amended by First Amendment thereto dated December 31, 1998 between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.1 to Registrant's quarterly reports on Form 10-Q for the quarters ended September 30, 1998 and June 30, 1999.
10.2.2†	—	Amended and Restated Employment Agreement dated as of July 1, 1998, as amended by First Amendment thereto dated December 31, 1998 between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Registrant's quarterly reports on Form 10-Q for the quarters ended September 30, 1998 and June 30, 1999.
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 Registrant's registration statement on Form S-1 (No. 333-45872).
10.2.5†	—	Employment Agreement dated as of July 1, 2000 between Steven C. Dixon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.5 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 2000.
10.2.6†	—	Employment Agreement dated as of July 1, 2000 between J. Mark Lester and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.6 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 2000.
10.2.7†	—	Employment Agreement dated as of July 1, 2000 between Henry J. Hood and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.7 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 2000.

Exhibit Number		Description
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 Registrant'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 Registrant'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 Registrant and its subsidiaries. Incorporated herein by reference to Exhibit 10.30 to Registrant's registration statement on Form S-1 (No. 33-55600).
10.4.1*	—	Amended and Restated Consulting Agreement dated January 11, 2001 between Chesapeake Energy Corporation and Michael Paulk.
10.4.2*	—	Amended and Restated Consulting Agreement dated January 11, 2001 between Chesapeake Energy Corporation and Steven P. Ensz.
10.5	—	Rights Agreement dated July 15, 1998 between the Registrant and UMB Bank, N.A., as Rights Agent. Incorporated herein by reference to Exhibit 1 to Registrant'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 Registrant'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 Registrant'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.
21*	—	Subsidiaries of Registrant
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 PricewaterhouseCoopers LLP
23.6*	—	Consent of Lee Keeling and Associates, Inc.

* Filed previously.

** Filed herewith.

† Management contract or compensatory plan or arrangement.

(b) Reports on Form 8-K

During the quarter ended December 31, 2000, Chesapeake filed the following current reports on Form 8-K:

On October 4, 2000, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing a dividend on preferred shares.

On October 23, 2000, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing third quarter earnings and providing information for a conference call with management.

On October 26, 2000, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release reporting record results for the third quarter of 2000.

On November 14, 2000, we filed a current report on Form 8-K providing under Item 9 guidance on future financial performance with respect to the fourth quarter of 2000 and full year 2001.

On November 16, 2000, we filed a current report on Form 8-K providing under Item 9 guidance on future financial performance with respect to the fourth quarter of 2000 and full year 2001.

On December 4, 2000, we filed a current report on Form 8-K providing under Item 9 guidance on future financial performance with respect to the fourth quarter of 2000 and full year 2001.

On December 18, 2000, we filed a current report on Form 8-K including under Item 5 an amendment to the description of our capital stock contained in our Registration Statement on Form 8-B (No. 001-13726).

On December 21, 2000, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release reporting a major exploratory success, increased 2001 capital expenditure budget, higher production and cash flow forecasts and an update on the Gothic merger.

On December 21, 2000, we filed a current report on Form 8-K providing under Item 9 guidance on future financial performance with respect to the fourth quarter of 2000 and full year 2001.

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.

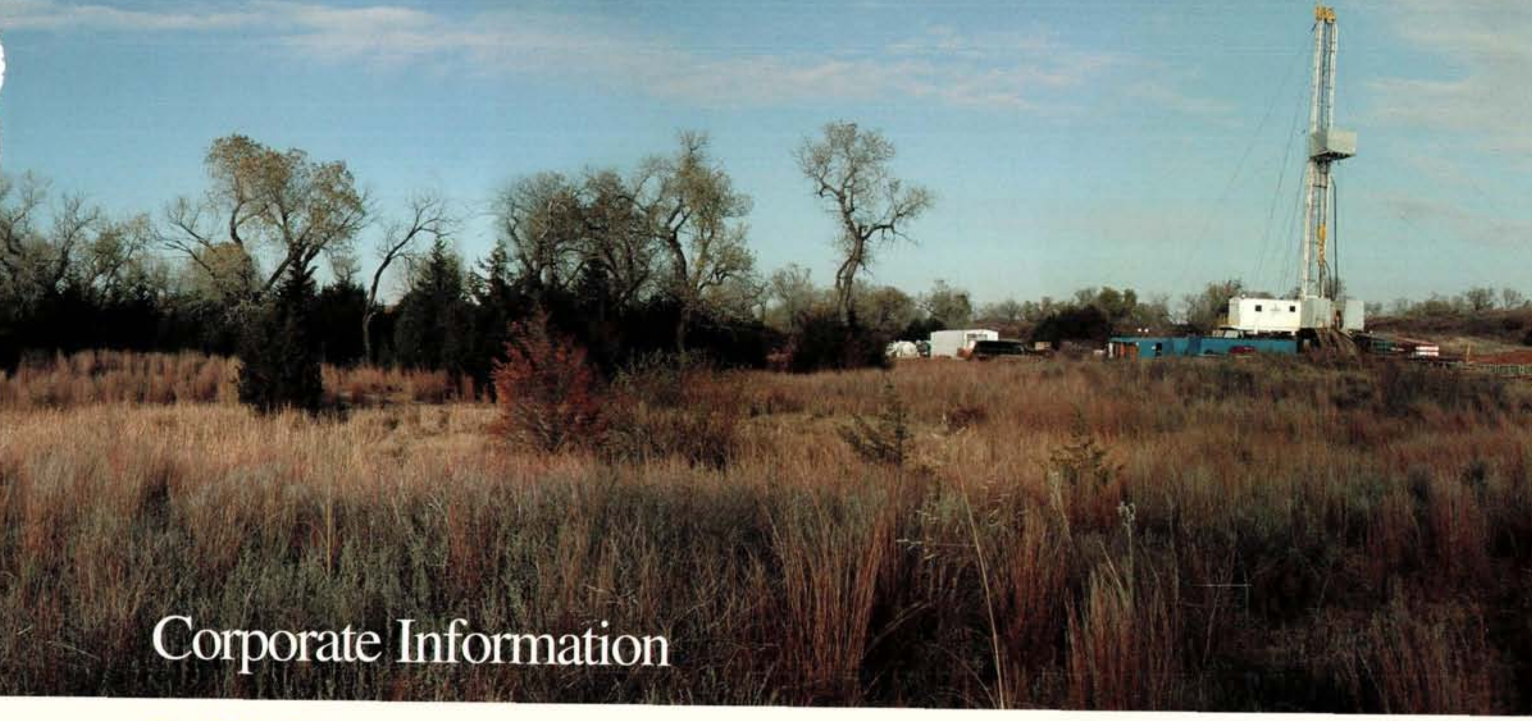
CHESAPEAKE ENERGY CORPORATION

By /s/ AUBREY K. McCLENDON
Aubrey K. McClendon
Chairman of the Board and Chief Executive Officer

Date: April 3, 2001

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.

Signature	Title	Date
/s/ AUBREY K. McCLENDON Aubrey K. McClendon	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	April 3, 2001
/s/ TOM L. WARD Tom L. Ward	President, Chief Operating Officer and Director (Principal Executive Officer)	April 3, 2001
/s/ MARCUS C. ROWLAND Marcus C. Rowland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	April 3, 2001
/s/ MICHAEL A. JOHNSON Michael A. Johnson	Senior Vice President — Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	April 3, 2001
/s/ EDGAR F. HEIZER, JR. Edgar F. Heizer, Jr.	Director	April 3, 2001
/s/ BREENE M. KERR Breene M. Kerr	Director	April 3, 2001
/s/ SHANNON T. SELF Shannon T. Self	Director	April 3, 2001
/s/ FREDERICK B. WHITTEMORE Frederick B. Whittemore	Director	April 3, 2001



Corporate Information

Stock Price Data

2000	High	Low	Last
First Quarter	$ 3.31	$1.94	$3.25
Second Quarter	8.00	2.75	7.88
Third Quarter	8.25	5.31	7.19
Fourth Quarter	10.50	5.44	10.13
1999			
First Quarter	$ 1.50	$0.63	$1.38
Second Quarter	2.94	1.31	2.94
Third Quarter	4.13	2.75	3.88
Fourth Quarter	3.88	2.13	2.38

Stock Split History

December 1994; two-for-one

December 1995; three-for-two

June 1996; three-for-two

December 1996; two-for-one

Trustees for the Company's Senior Notes

United States Trust Company
of New York
114 West 47th Street
New York, New York 10036

Internet Address

Company financial information, public disclosures and other information are available at Chesapeake's website www.chkenergy.com or by contacting Thomas S. Price, Jr., at (405) 879-9257 or tprice@chkenergy.com.

Common Stock

Chesapeake Energy Corporation's common stock is listed on the New York Stock Exchange under the symbol CHK. As of April 12, 2001, there were approximately 41,000 beneficial owners of the common stock.

Common Stock Dividends

The payment of future cash dividends, if any, will be reviewed periodically by the Board of Directors and will depend upon, among other things, the company's financial condition, funds from operations, the level of its capital and development expenditures, its future business prospects and any contractual restrictions.

Corporate Headquarters

6100 North Western Avenue
Oklahoma City, Oklahoma 73118
(405) 848-8000

Independent Public Accountants

PricewaterhouseCoopers LLP
15 North Robinson, Suite 400
Oklahoma City, Oklahoma 73102
(405) 236-5800

Stock Transfer Agent and Registrar

UMB Bank, N.A.
928 Grand Blvd.
Kansas City, Missouri 64106
(816) 860-7760

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to the transfer agent.

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.

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 in Item 1 of our 2000 10-K and include: the volatility of oil and gas prices, our substantial indebtedness, our commodity price risk management activities, our ability to replace reserves, the availability of capital, uncertainties inherent in estimating quantities of oil and gas reserves, projecting future rates of production and the timing of development expenditures, uncertainties in evaluating oil and gas reserves of acquired properties and associated potential liabilities, drilling and operating risks, our ability to generate future taxable income sufficient to utilize our net operating losses before expiration, future ownership changes which could result in additional limitations to our net operating losses, adverse effects of governmental and environmental regulation, losses possible from pending or future litigation, the strength and financial resources of our competitors 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 our 2000 10-K, 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 SEC that attempt to advise interested parties of the risks and factors that may affect our business.

Photos by Keith Rinearson

Chesapeake

Chesapeake

Natural Gas.
Natural Advantages.

Chesapeake Energy Corporation

6100 North Western Avenue

Oklahoma City, Oklahoma 73118

www.chkenergy.com