CHESAPEAKE
ENERGY CORPORATION

1998 Annual Report

Selected Financial Data

	Year Ended December 31,		Six Months Ended December 31,		Year Ended June 30,			
	1998	1997	1997	1996	1997	1996	1995	1994
Statement of Operations Data								
($ in thousands, except per share data)								
Oil and gas sales	$ 256,887	$198,410	$ 95,657	$ 90,167	$ 192,920	$110,849	$ 56,983	$ 22,404
Oil and gas marketing sales	121,059	104,394	58,241	30,019	76,172	28,428	–	–
Oil and gas service operations	–	–	–	–	–	6,314	8,836	6,439
Total revenues	377,946	302,804	153,898	120,186	269,092	145,591	65,819	28,843
Production expenses	51,202	14,737	7,560	4,268	11,445	6,340	3,379	2,141
Production taxes	8,295	4,590	2,534	1,606	3,662	1,963	877	1,506
Oil and gas marketing expenses	119,008	103,819	58,227	29,548	75,140	27,452	–	–
Oil and gas service operations	–	–	–	–	–	4,895	7,747	5,199
Impairment of oil and gas properties	826,000	346,000	110,000	–	236,000	–	–	–
Impairment of other assets	55,000	–	–	–	–	–	–	–
Oil and gas depreciation, depletion and amortization	146,644	127,429	60,408	36,243	103,264	50,899	25,410	8,141
Depreciation and amortization of other assets	8,076	4,360	2,414	1,836	3,782	3,157	1,765	1,871
General and administrative	19,918	10,910	5,847	3,739	8,802	4,828	3,578	3,135
Total operating costs	1,234,143	611,845	246,990	77,240	442,095	99,534	42,756	21,993
Income (loss) from operations	(856,197)	(309,041)	(93,092)	42,946	(173,003)	46,057	23,063	6,850
Other income (expense):								
Interest and other income	3,926	87,673	78,966	2,516	11,223	3,831	1,524	981
Interest expense	(68,249)	(29,782)	(17,448)	(6,216)	(18,550)	(13,679)	(6,627)	(2,676)
Total other income (expense)	(64,323)	57,891	61,518	(3,700)	(7,327)	(9,848)	(5,103)	(1,695)
Income (loss) before income taxes and extraordinary item	(920,520)	(251,150)	(31,574)	39,246	(180,330)	36,209	17,960	5,155
Provision (benefit) for income taxes	–	(17,898)	–	14,325	(3,573)	12,854	6,299	1,250
Income (loss) before extraordinary item	(920,520)	(233,252)	(31,574)	24,921	(176,757)	23,355	11,661	3,905
Extraordinary item:								
Loss on early extinguishment of debt, net of applicable income taxes	(13,334)	(177)	–	(6,443)	(6,620)	–	–	–
Net income (loss)	(933,854)	(233,429)	(31,574)	18,478	(183,377)	23,355	11,661	3,905
Preferred stock dividends	(12,077)	–	–	–	–	–	–	–
Net income (loss) available to common shareholders	(945,931)	(233,429)	(31,574)	18,478	(183,377)	23,355	11,661	3,905
Earnings (loss) per share	(9.97)	(3.30)	(0.45)	0.28	(2.79)	0.40	0.21	0.08
Operating cash flow	115,200	226,639	141,248	77,325	162,716	90,265	45,135	15,167
Operating cash flow per share	1.21	3.21	1.99	1.17	2.47	1.55	0.81	0.31
EBITDA	183,449	256,421	158,696	83,541	181,266	103,944	51,762	17,843
EBITDA per share	1.93	3.63	2.24	1.26	2.76	1.78	0.93	0.37
Weighted average shares outstanding	94,911	70,672	70,835	66,300	65,767	58,342	55,872	48,240
Property Data *($ in thousands)*								
Oil reserves (MBbls)	22,593	18,226	18,226	*	17,373	12,258	5,116	4,154
Gas reserves (MMcf)	955,791	339,118	339,118	*	298,766	351,224	211,808	117,066
Reserves in equivalent thousand barrels	181,891	74,746	74,746	*	67,167	70,795	40,417	23,665
Reserves in equivalent million cubic feet	1,091,348	448,474	448,474	*	403,004	424,775	242,505	141,992
Future net revenues discounted at 10%	$ 660,991	$466,509	$466,509	$ *	$ 437,386	$ 547,016	$ 188,137	$141,249
Future net revenues undiscounted	$1,208,641	$715,098	$715,098	$ *	$ 611,954	$ 795,600	$ 274,900	$209,795
Oil production (MBbls)	5,976	3,511	1,857	1,116	2,770	1,413	1,139	537
Gas production (MMcf)	94,421	59,236	27,326	30,095	62,005	51,710	25,114	6,927
Production in equivalent thousand barrels	21,713	13,384	6,411	6,132	13,104	10,031	5,325	1,692
Production in equivalent million cubic feet	130,277	80,302	38,468	36,791	78,625	60,190	31,974	10,152
Average oil price ($ per Bbl)	12.70	19.39	18.59	21.88	20.93	17.85	17.36	15.09
Average gas price ($ per Mcf)	1.92	2.20	2.24	2.18	2.18	1.66	1.48	2.06
Average gas equivalent price ($ per Mcfe)	1.97	2.47	2.49	2.45	2.45	1.84	1.78	2.21

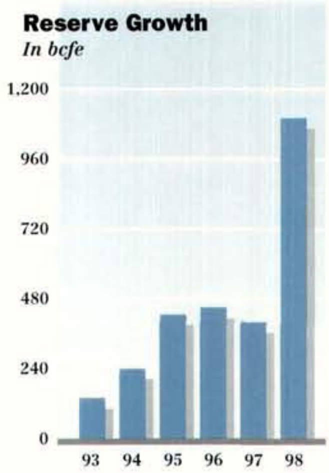
**An independent appraisal of the company's oil and gas reserves was not performed as of December 31, 1996, because the company's fiscal year-end at that time was June 30.*

Table of Contents

Chesapeake Energy Corporation is an independent oil and natural gas producer headquartered in Oklahoma City. The company's operations are focused on developmental drilling and producing property acquisitions in three major onshore natural gas producing areas of the United States and Canada. The company's Internet address is www.chesapeake-energy.com.

Letter to Shareholders

During 1998, a very difficult and challenging year for the oil and gas industry, Chesapeake completed the strategic repositioning effort it began in late 1997. Our goal was to reduce the company's risk profile, generate more attractive drilling results and build an inventory of long-lived natural gas reserves – the fuel of choice for the 21st century. Completely transformed, Chesapeake now owns 1.1 trillion cubic feet equivalent (tcfe) of proved oil and gas reserves, one of the 20 largest inventories of onshore U.S. natural gas, and is well positioned to benefit when natural gas prices recover.



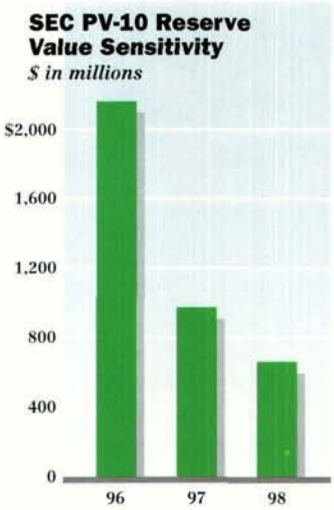
Chesapeake's oil and gas reserves increased by a compounded annual rate of 51% from 1993 to 1998.

Building long-term natural gas reserves

Prior to our transformation, Chesapeake was known primarily as an innovative exploration company that grew rapidly during 1994–96 through the application of advanced-technology horizontal drilling on its large leasehold inventory in the Texas Austin Chalk area. Despite high expectations in the industry and on Wall Street for the vast potential of extending the Austin Chalk Trend into Louisiana, falling oil prices and significant geological and engineering challenges generated disappointing returns for all operators involved.

To recover from this major setback and to better position the company for the coming growth in the natural gas industry, Chesapeake successfully transformed itself during the second half of 1997 and the first half of 1998. Unfortunately, during the process, we incurred substantial debt at the same time that oil and natural gas prices began to fall precipitously. To date, these factors have resulted in a market valuation that does not reflect the true value of Chesapeake's long-lived natural gas assets.

Chesapeake is confident that natural gas is the long-term, environmentally sensitive answer to the nation's energy needs. Based on this belief and on our expertise in increasing value from natural gas assets, Chesapeake completed eight major property acquisitions in 1998. The 750 billion cubic feet of natural gas equivalent (bcfe) of acquired properties significantly strengthened the company, preparing it for a brighter future with higher natural gas prices. Acquired for a $700 million combination of cash and Chesapeake common stock, these properties:



Dramatically lower oil and gas prices have caused the discounted present value of Chesapeake's reserve base of 1.1 tcfe (pro forma for acquisitions) to fall by more than $1.4 billion during the past two years.

- nearly tripled Chesapeake's oil and gas reserves to 1,091 bcfe;
- doubled the company's reserves-to-production index from five years to 10 years;
- increased the percentage of natural gas reserves from 70% to 87%;
- raised the percentage of proved developed reserves by value from 66% to 78%;
- increased 1998's oil and gas production by 62%.

We are confident that our acquisitions will add substantial value in the long-term. However, full-cost accounting standards have resulted in a series of asset writedowns reflecting exceptionally low oil and gas prices ($10.48 per barrel and $1.68 per mcf) as of December 31, 1998. These prices are the lowest inflation-adjusted prices in the past 50 years and yield unrealistic values for Chesapeake's reserves. Factoring in the two-year decline in oil and gas prices, the present value (discounted at 10%) of Chesapeake's reserves has decreased from approximately

Rising demand. Demand for natural gas is increasing rapidly, up 18% over the past decade, and is projected to grow 35% by the year 2010.

$2.1 billion (pro forma for acquisitions) as of January 1, 1997 to $661 million as of December 31, 1998, leading to significant asset writedowns in 1998 and 1997.

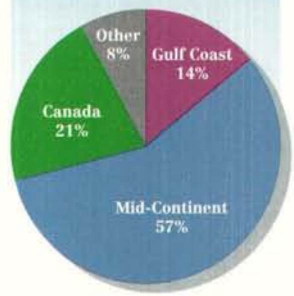
An important feature of how we built our long-life gas reserve base is that we used long-term capital. We have no net bank debt and our earliest senior debt maturity is in 2004. Even at today's unusually low oil and gas prices, we have sufficient cash flow to pay interest on our debt and fund a capital program sufficient to maintain our reserve base. We are confident Chesapeake has enough staying power to wait for the eventual turnaround in prices, which should lead to a dramatic increase in the value of our oil and gas assets.

First-class assets in three gas-rich areas

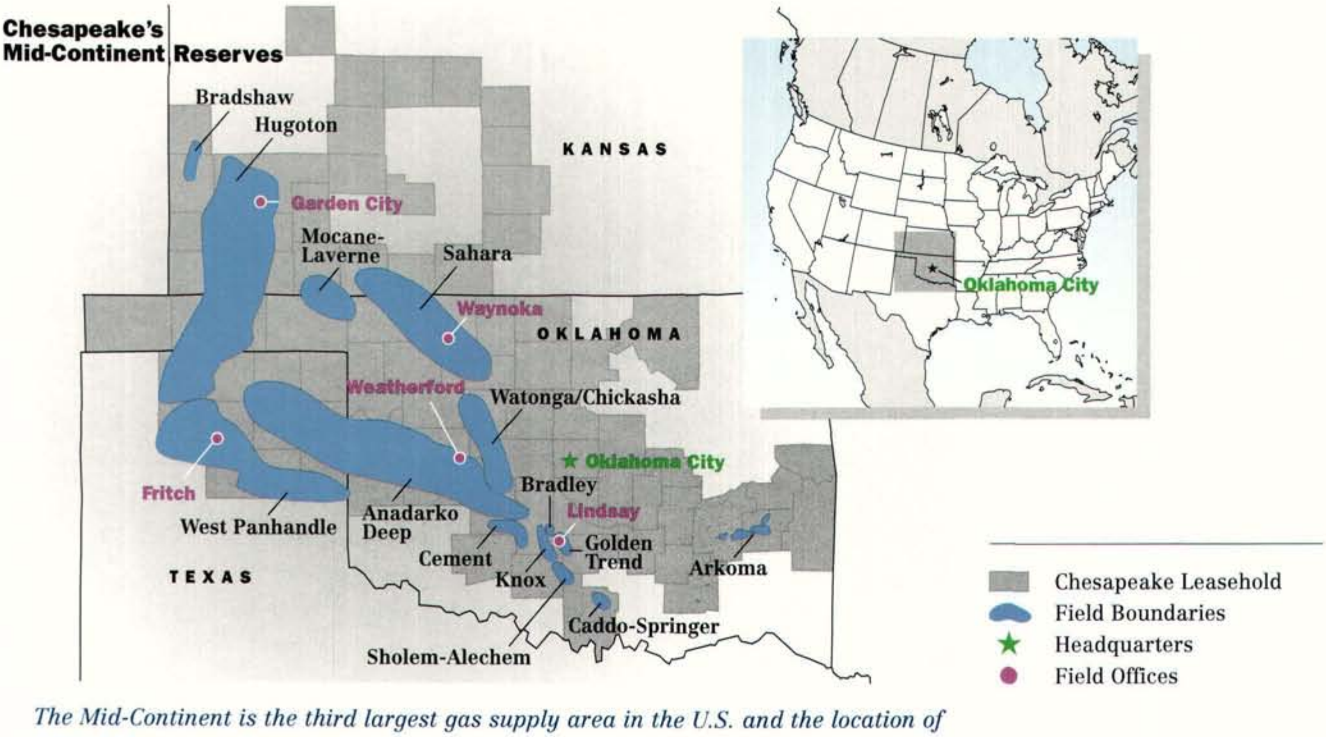
Despite the large non-cash impairment charges, we are pleased with the strength of our asset base and the value we have added in just the first year of owning our acquired properties. Chesapeake's portfolio of assets is concentrated in three major areas: the Mid-Continent region, the onshore Gulf of Mexico, and in far northeastern British Columbia, Canada. All of these project areas are characterized by a high concentration of valuable natural gas reserves. They are also areas where Chesapeake has a substantial asset base, significant technological expertise, and a large inventory of undeveloped leasehold with low-risk development drilling opportunities and high-impact exploratory projects. In the years ahead, the company's strategy is to continue building on its economies of scale in these core asset areas through value-enhancing drillbit activity and by further consolidating our ownership in these areas.

We are particularly interested in building Chesapeake's asset base in the Mid-Continent area of the U.S., which includes Oklahoma, Kansas and the Texas

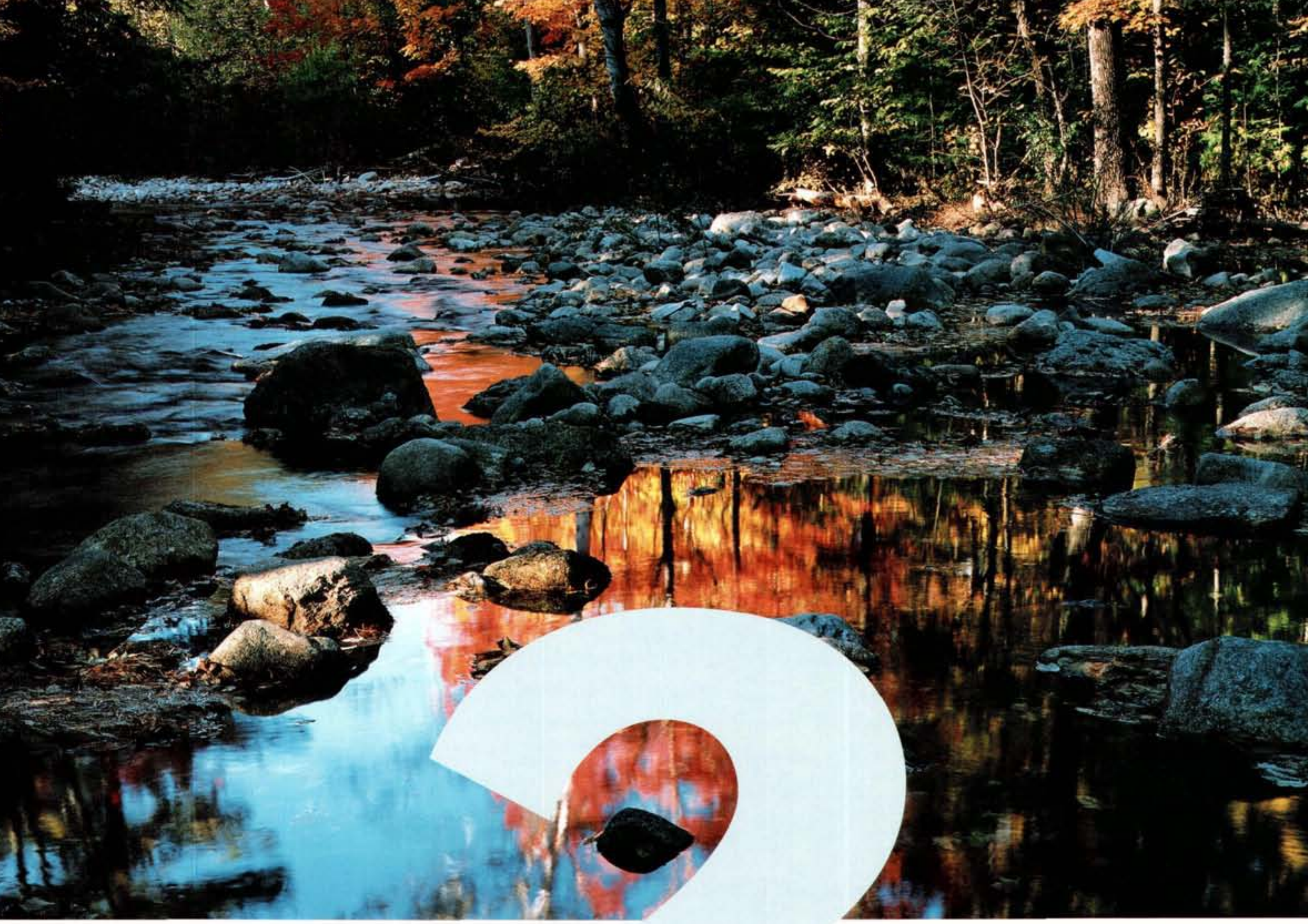
Total Reserves



92% of Chesapeake's oil and gas reserves are concentrated in its three core operating areas.



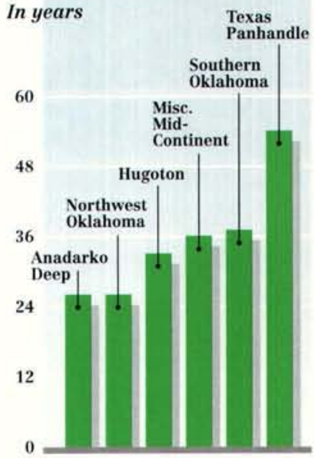
The Mid-Continent is the third largest gas supply area in the U.S. and the location of 57% of Chesapeake's reserves.



Clean energy. *Natural gas is the cleanest fuel available, producing 50% less carbon emissions than coal and 30% less than fuel oil.*

Panhandle. The Mid-Continent is the third largest gas supply area in the U.S., exceeded only by the offshore and onshore Gulf of Mexico regions. Characterized by long reserve lives, attractive lifting costs, excellent gas markets and abundant consolidation opportunities, the Mid-Continent is Chesapeake's operating backyard and the location of 57% of its reserves. The wisdom of increasing our assets in the Mid-Continent is particularly apparent during this time of historically low prices. Many of Chesapeake's Mid-Continent properties will continue producing for decades, and we believe these long-lived assets will enable the company to outlast what we anticipate will be a relatively brief period of low natural gas prices. Afterwards, we expect to prosper as natural gas prices increase substantially as a result of declining supply and rising demand.

Chesapeake's Key Fields' Reserve Lives
In years



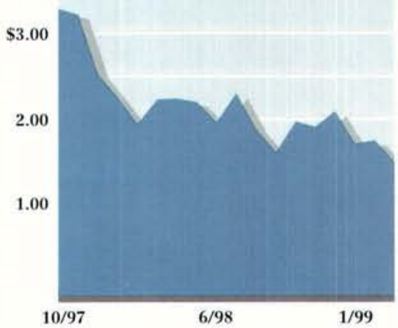
Chesapeake's Mid-Continent reserves are projected to continue producing for an average of 40 years.

Lessons from past cycles

Over the past 20 years, Chesapeake's management team has witnessed a number of down cycles in the energy industry: 1982–83, 1985–86, 1991–92 and 1994–95 come to mind. Although the current cycle has been unusually severe, history reinforces the wisdom of contrarians who understand that powerful self-correcting market forces generate strong price recoveries following cyclical downturns like the current one. While some investors may be reluctant to invest in this sector during tough times, Chesapeake's management knows that price collapses provide the foundation for improved valuations in the future. Simply put, low prices cure low prices as consumers are motivated to consume more and producers are compelled to produce less. Furthermore, his-tory tells us that the depth of this cycle assures a coming recovery in natural gas prices that is likely to be faster and more powerful than most observers realize.

Based upon an expected 50% reduction in drilling levels for new reserves in 1999 and the depletion of existing wells accelerating to annual rates of 15–20%, we anticipate that U.S. gas production may fall 5–10% in the next 18–24 months. With overall demand projected to increase by as much as 10% during the same period, Chesapeake believes a substantial increase in natural gas prices may be just ahead, possibly as soon as in the second half of 1999. With our 1.1 tcfe of natural gas reserves, low operating cost structure, substantial inventory of low-risk drilling projects, operational expertise to rejuvenate acquired properties and a high-potential 3-D seismic exploration program, Chesapeake is poised to benefit from the strong market forces shaping the future of the natural gas industry.

Two Years of Declining Natural Gas Prices



After peaking in the winter of 1996–97, natural gas prices have fallen significantly because of two record warm winters in a row.

The long-term case for natural gas

Every day more residential, commercial and industrial consumers select natural gas as their fuel of choice. Natural gas is America's best energy value at an average cost of 25% less than electricity and 15% less than fuel oil. It is also the most environmentally sensitive fuel – the same level of energy derived from burning natural gas generates 50% less carbon emissions than coal and 30% less than fuel oil.

The electricity generation sector is a major component of the projected strong demand growth for natural gas. This past summer's extremely volatile electric

Home grown. Natural gas is discovered, produced and consumed in North America, keeping it free from worldwide political and economic fluctuations.

utility markets demonstrated that electrical generating capacity has not kept up with rising demand for electricity. As a result, an estimated 45,000 megawatts of new gas-fired electrical generating units are scheduled to come on line by 2001. This alone could increase natural gas demand by an additional 2–4% per year, just as production declines should begin accelerating from the severe contraction in drilling activity.

In addition, increasingly stringent environmental standards will create an even greater reliance on gas-fired generation. The Environmental Protection Agency has recently issued a rule that requires 22 states east of the Mississippi River to lower their emissions by 28% before the year 2007. This rule strongly favors gas-fired generation over coal-fired facilities. Though nuclear power plants still provide 20% of the nation's electricity, during the next 20 years up to 75% of these facilities will likely be decommissioned and replaced by natural gas-fired power plants. Rising electricity usage, decreasing nuclear power capability and the significant environmental benefits of natural gas should make natural gas America's fuel of choice in the 21st century.

Electrical generation will increase from fourth on the gas consumption list today to first by 2020 as 1,100 gas-fired electrical generating plants are built.

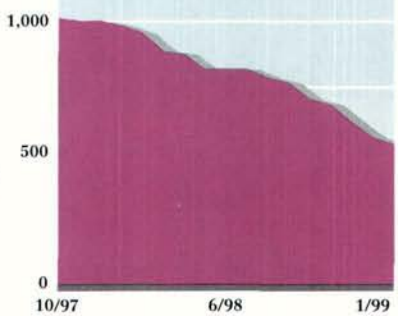
—Energy Information Agency January 1999

Favorable supply and demand trends

In the face of these impressive demand trends, the oil and gas industry will have to generate significant supply increases. If present growth trends continue, natural gas demand increases of 2–4% per year will require a supply increase from approximately 22 tcf in 1998 to 30 tcf in 2010. To satisfy this demand, the U.S. natural gas industry will be required to discover over 200 tcf of new natural gas reserves in the next 10 years, a task we believe the industry cannot accomplish without significantly higher natural gas prices. Our conclusion that gas demand will greatly outstrip supply in the next decade was the motivating factor behind Chesapeake's natural gas-focused acquisitions in 1997 and 1998, and our willingness to increase Chesapeake's debt in funding the acquisitions.

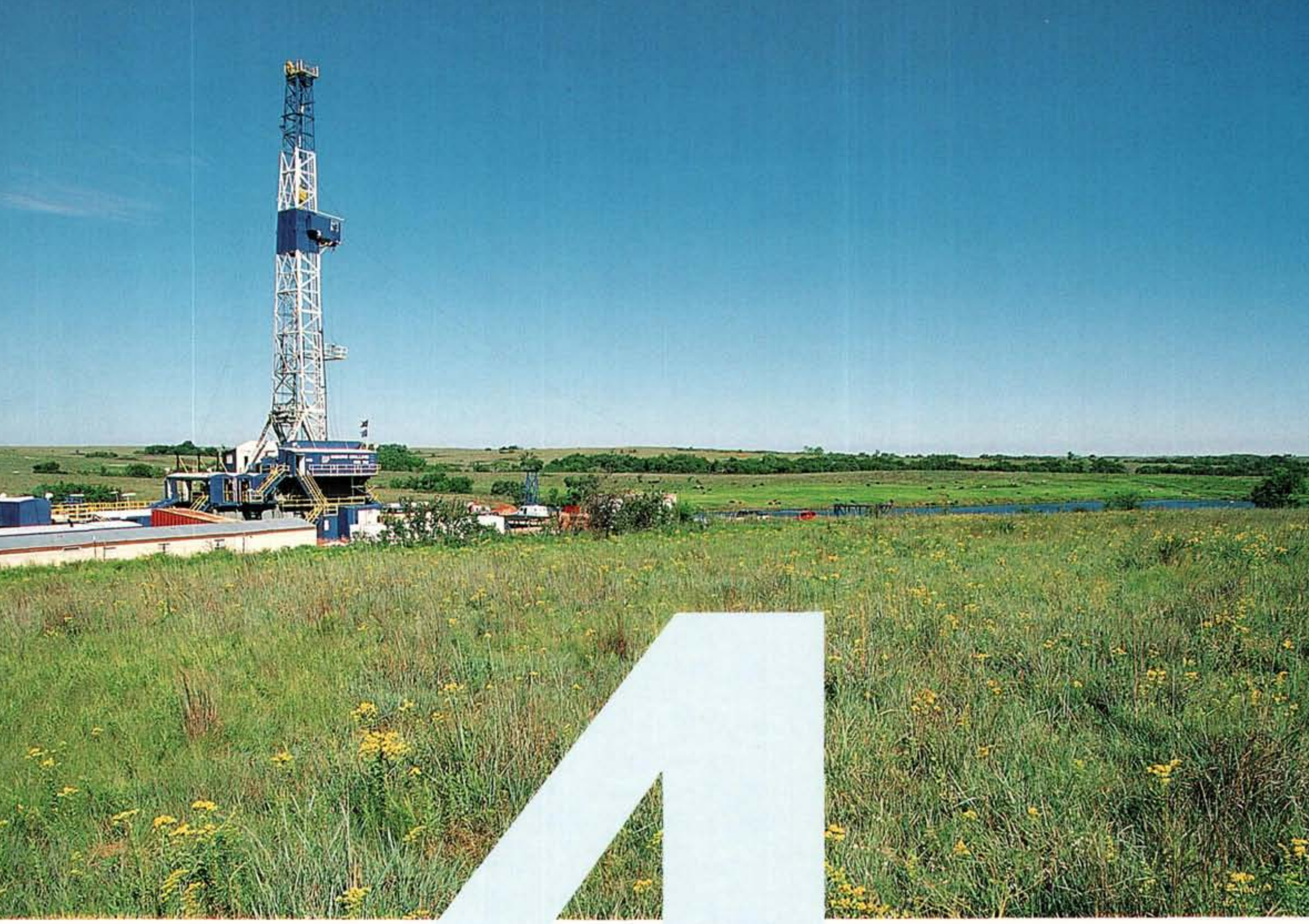
During the past two years, energy companies invested an estimated $50 billion in drilling new U.S. wells, increasing the active rig count by over 40% to more than 1,000 rigs in February 1998. Despite these record expenditures, the nation's gas production level increased by only 1% per year. Today's rig count of around 500, barely half of last year's, is the lowest level since industry record keeping began in 1944. By way of comparison, an all-time high of 4,530 rigs were drilling in December 1981, which represents an 88% reduction in drilling activity during the past 18 years.

U.S. Rig Count



Today's rig count is 50% less than last year's and 88% below 1981's record levels.

Several factors have contributed to the lack of production growth. In the Gulf of Mexico, the most important gas supply basin in the U.S., a huge increase in drilling activity in 1995–98 resulted in no net supply increase. Finding costs were much higher than projected, and annual depletion rates approaching 30–40% in the high-deliverability, short-reserve life, shallow-water region overwhelmed the increased drilling activity, leaving the area with an average reserve life of less than five years. Further deepening the expected supply declines in the years ahead is the large reduction in rigs working the Gulf, from 140 in February 1998 to 100 today. The heavy concentration of drilling during the past few years in other



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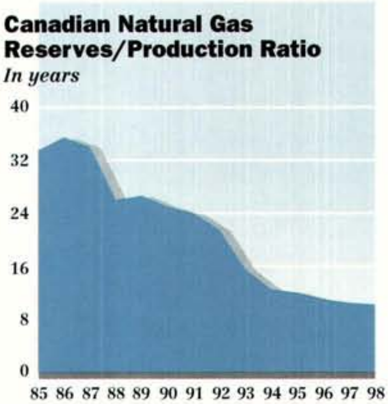
Chesapeake's strategic position.

We are well positioned to capitalize on the strengthening natural gas market, with significant reserves, land inventory and drillbit expertise in three key gas-rich areas in North America.

high-deliverability, short-reserve life areas such as the Austin Chalk and Cotton Valley Pinnacle Reef trends has compounded the Gulf supply problem.

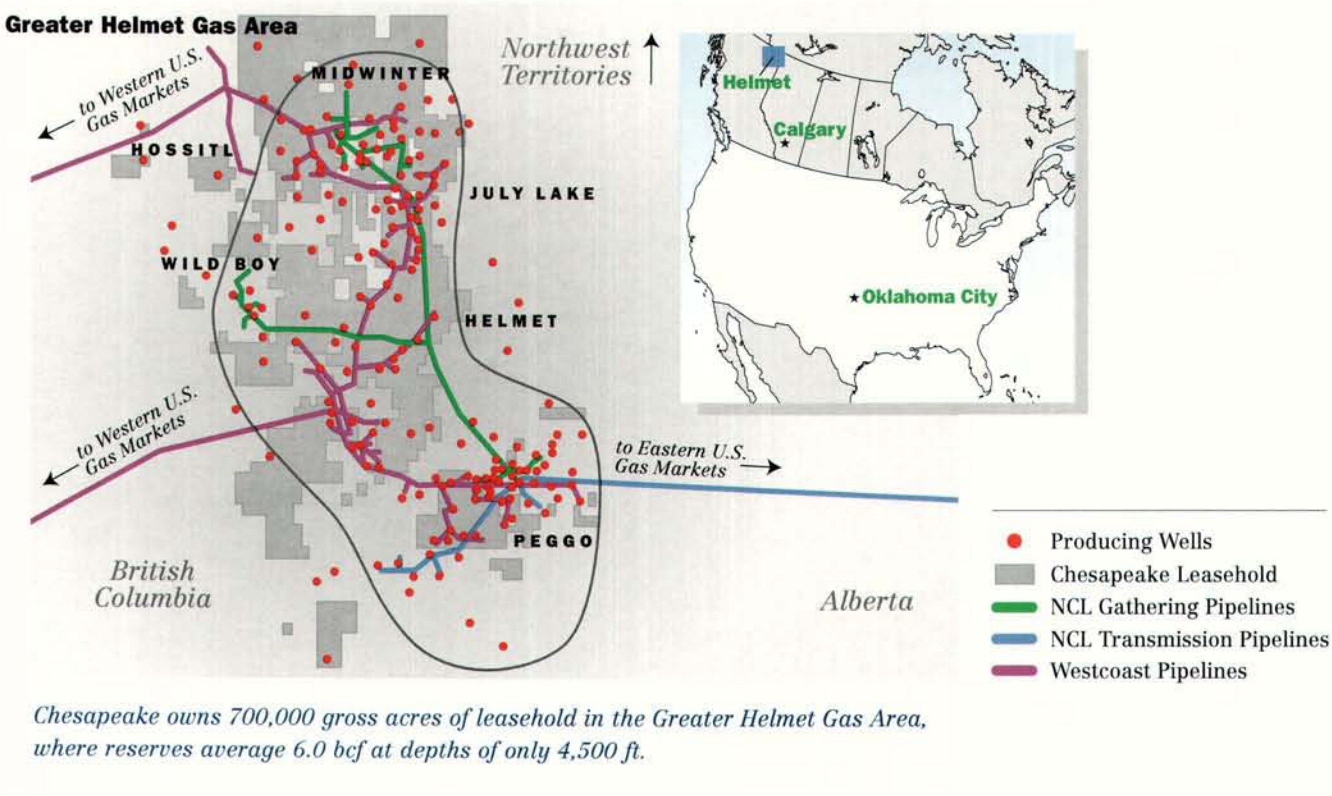
Many investors believe that the gas production required to meet increasing U.S. demand and overcome U.S. supply problems will come from Canada. While this has been true during the past 10 years, we believe gas supply problems are as challenging for the Canadian industry as they are for U.S. producers. We do not believe Canadian natural gas productivity can expand in the near term to fill the new Canadian pipeline projects. The required level of Canadian gas well drilling to fill the pipelines when they come into service in 2001 is projected to be in excess of 8,000 newly completed gas wells per year, far exceeding the level of 4,500 wells projected to be drilled in 1999. Further compounding the Canadian supply challenge is a well depletion problem similar to that in the U.S., with annual reservoir decline rates now approaching 20%.



Canadian reserve additions during the past 15 years have not kept up with production increases, leading to a dramatic reduction in Canada's reserve life index.

Acting decisively to enhance asset value

To ensure adequate liquidity, Chesapeake has significantly reduced its capital expenditures for 1999, matching the company's drilling budget with its expected cash flows from production and miscellaneous asset sales. Because service costs are down, our dollars are going further and achieving much lower finding and development costs. The 1999 budget is mostly allocated to low-risk, development drilling opportunities in the Helmet area of northeastern British Colombia and in the Mid-Continent, including Sahara in northwest Oklahoma, West Panhandle in the Texas Panhandle, and the Knox/Bradley/Cement and Watonga-Chickasha areas in west central Oklahoma.



Chesapeake owns 700,000 gross acres of leasehold in the Greater Helmet Gas Area, where reserves average 6.0 bcf at depths of only 4,500 ft.

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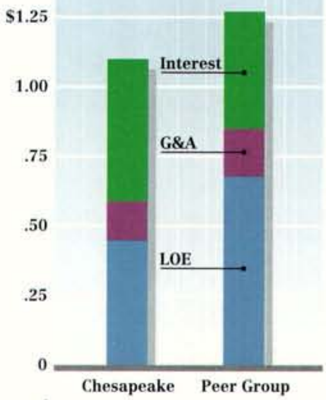
A brighter future. The future is bright for natural gas companies. The Chesapeake team is committed to surviving these challenging times and prospering in the years ahead.

In these core areas, Chesapeake will concentrate on improving operational efficiencies, increasing production through the installation of additional compression facilities and completing various production stimulation programs and mechanical reworks. The remaining budget is dedicated to higher-potential, higher-risk areas such as the Tuscaloosa Trend in Louisiana and the Austin Chalk Trend in Texas.

We are also continuing to reduce Chesapeake's already low operating costs though our program of selling approximately 1,000 low margin oil properties. To date, we have generated proceeds of $40 million with an additional $45 million of sales projected for later this year.

In addition, the company has reduced its general and administrative expenses. After completing eight acquisitions in early 1998, we have reduced Chesapeake's pro forma overhead expense by 40%. Recently, we further reduced staff by consolidating our Texas and Louisiana district offices into our Oklahoma City headquarters.

Chesapeake's Costs vs. Peers' Costs



In spite of higher interest costs, Chesapeake's operating cost structure is nearly 15% below that of its peers because of our exceptionally low lease operating and G&A expenses.

Looking Forward

To continue enhancing the value of Chesapeake's assets, we are building our inventory of drilling opportunities and retaining our best employees. We have a strong technical team that rigorously reviews all of our assets to identify the best opportunities to increase production and reserves. It is important for you to know that Chesapeake's management, directors and employees own 30% of the company's outstanding common shares. This level of ownership, among the highest levels in our industry, keeps all Chesapeake employees focused on our goal of continuing to build a first-class inventory of natural gas projects.

We believe the fundamental value of Chesapeake's natural gas reserves will move up dramatically in the near future. All of our efforts are designed to reach this point with the best set of assets and the highest quality people possible. We believe the wisdom of our transformation to a long-lived natural gas producer will be strongly vindicated and that better days are ahead for Chesapeake and our shareholders in 1999 and beyond.

Aubrey K. McClendon

Tom L. Ward

March 15, 1999

Board of Directors

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

Aubrey K. McClendon has served as Chairman of the Board, Chief Executive Officer and a director of the company since its inception in 1989. From 1982 to 1989, Mr. McClendon was an independent producer of oil and gas in affiliation with Tom L. Ward, the company's President and Chief Operating Officer. Mr. McClendon is a member of the Board of Visitors of the Fuqua School of Business at Duke University, an Executive Committee member of the Texas Independent Producers and Royalty Owners Association, a director of the Oklahoma Independent Petroleum Association and a director of the Louisiana Independent Oil and Gas Association. Mr. McClendon is a 1981 graduate of Duke University.

Tom L. Ward
President, Chief Operating Officer and Director

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

E.F. Heizer, Jr.
Director

E. F. Heizer, Jr. has been a director of the company since 1993. From 1985 to the present, Mr. Heizer has been a private venture capitalist. He founded Heizer Corporation, a publicly traded business development company, in 1969 and served as Chairman and Chief Executive Officer from 1969 until 1986, when Heizer Corporation was reorganized into a number of public and private companies. Mr. Heizer was Assistant Treasurer of the Allstate Insurance Company from 1962 to 1969 in charge of Allstate's venture capital operations. He was employed by Booz, Allen and Hamilton from 1958 to 1962, Kidder, Peabody & Co. from 1956 to 1958 and Arthur Andersen & Co. from 1954 to 1956. He serves on the advisory board of the Kellogg School of Management at Northwestern University. Mr. Heizer is a director of Material Science Corporation in Elk Grove, Illinois, and several private companies. Mr. Heizer graduated from Northwestern University in 1951 and from Yale University Law School in 1954.

Breene M. Kerr
Director

Breene M. Kerr has been a director of the company since 1993. He is Vice Chairman of Seven Seas Petroleum Corporation, Houston, Texas, an exploration and production company with operations in Colombia, South America. In 1969, Mr. Kerr founded Kerr Consolidated, Inc., which was sold in 1996. In 1969, Mr. Kerr co-founded the Resource Analysis and Management Group and remained its senior partner until 1982. From 1967 to 1969, he was Vice President of Kerr-McGee Chemical Corporation. From 1951 through 1967, Mr. Kerr worked for Kerr-McGee Corporation as a geologist and land manager. Mr. Kerr has served as chairman of the Investment Committee for the Massachusetts Institute of Technology and is a life member of the Corporation (Board of Trustees) of that university. He served as a director of Kerr-McGee Corporation from 1957 to 1981. Mr. Kerr currently is a trustee and serves on the Investment Committee of the Brookings Institute in Washington, D.C., and has been an associate director since 1987 of Aven Gas & Oil, Inc., an oil and gas property management company located in Oklahoma City. Mr. Kerr graduated from the Massachusetts Institute of Technology in 1951.

Shannon T. Self
Director

Shannon T. Self has been a director of the company since 1993. He is a shareholder of Self, Giddens & Lees, Inc., Attorneys at Law, in Oklahoma City, which he co-founded in 1991. Mr. Self was an associate and shareholder in the law firm of Hastie and Kirschner, Oklahoma City, from 1984 to 1991 and was employed by Arthur Young & Co. from 1979 to 1980. Mr. Self is a member of the Visiting Committee of Northwestern University School of Law and a director of The Rock Island Group, a private computer firm in Oklahoma City. Mr. Self is a Certified Public Accountant. He graduated from the University of Oklahoma in 1979 and from Northwestern University Law School in 1984.

Frederick B. Whittemore
Director

Frederick B. Whittemore has been a director of the company since 1993. Mr. Whittemore has been an advisory director of Morgan Stanley & Co. since 1989 and was a managing director of Morgan Stanley & Co. from 1970 to 1989. He was Vice Chairman of the American Stock Exchange from 1982 to 1984. Mr. Whittemore is a director of Ecofin Limited, London; Partner Reinsurance Company, Bermuda; Maxcor Financial Group Inc., New York; SunLife of New York, New York; KOS Pharmaceuticals, Inc., Miami, Florida; and Southern Pacific Petroleum, Australia, NL. Mr. Whittemore graduated from Dartmouth College in 1953 and from the Amos Tuck School of Business Administration in 1954.

Walter C. Wilson
Director

Walter C. Wilson has been a director of the company since 1993. From 1963 to 1974 and from 1978 to 1997, Mr. Wilson was a general agent with Massachusetts Mutual Life Insurance Company. From 1974 to 1978, he was Senior Vice President of Massachusetts Mutual Life Insurance Company, and from 1958 to 1963 he was an agent with that company. Mr. Wilson is a member of the Board of Trustees of Springfield College, Springfield, Massachusetts, and is a director of Earth Satellite Corporation of Rockville, Maryland, and "Q" Companies, Inc. of Houston, Texas. Mr. Wilson graduated in 1958 from Dartmouth College.

Marcus C. Rowland
Executive Vice President and Chief Financial Officer

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

Steven C. Dixon
Senior Vice President–Operations

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

J. Mark Lester
Senior Vice President–Exploration

J. Mark Lester has been Senior Vice President – Exploration since 1995 and served as Vice President – Exploration from 1989 to 1995. From 1986 to 1989, Mr. Lester was employed by Messrs. McClendon and Ward. He was employed by various independent oil companies in Oklahoma City from 1980 to 1986 and was employed by Union Oil Company of California from 1977 to 1980 as a geophysicist. Mr. Lester graduated from Purdue University in 1975 and in 1977.

Henry J. Hood
Senior Vice President–Land and Legal

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

Ronald A. Lefaive

Senior Vice President–Accounting, Controller and Chief Accounting Officer

Ronald A. Lefaive has served as Senior Vice President – Accounting since March 1998 and as Controller and Chief Accounting Officer since 1993. From 1991 until his association with the company, Mr. Lefaive was Controller for Phibro Energy Production, Inc., an international exploration and production subsidiary of Phibro Energy Corporation, whose principal operations were located in Russia. From 1982 to 1991, Mr. Lefaive served as Assistant Controller, General Auditor and Manager of Management Information Systems at Conquest Exploration Company in Houston, Texas. Prior to joining Conquest, Mr. Lefaive held various financial staff and management positions with The Superior Oil Company from 1980 to 1982 and Shell Oil Company from 1975 to 1982. Mr. Lefaive is a Certified Public Accountant and graduated from the University of Houston in 1975.

Martha A. Burger

Treasurer and Vice President–Human Resources

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

Thomas L. Winton

Senior Vice President–Information Technology and Chief Information Officer

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

Thomas S. Price, Jr.

Vice President–Corporate Development

Thomas S. Price, Jr. has served as Vice President – Corporate Development since 1992 and was a consultant to the company during the prior two years. He was employed by Kerr-McGee Corporation, Oklahoma City, from 1988 to 1990 and by Flag-Redfern Oil Company from 1984 to 1988. Mr. Price is Vice Chairman of the Mid-Continent Oil and Gas Association, and a member of the Petroleum Investor Relations Association and the National Investor Relations Institute. Mr. Price graduated from the University of Central Oklahoma in 1983, from the University of Oklahoma in 1989 and from the American Graduate School of International Management in 1992.

Frank E. Jordan
Vice President–Production

Frank E. Jordan has served as Vice President – Production since February 1998. From 1994 to 1998, Mr. Jordan served in various engineering positions with the company, including District Manager – College Station in 1996 and Vice President – Drilling, Northern Division in 1997. Prior to joining the company, Mr. Jordan served as a drilling engineer for Sedco Forex Schlumberger from 1985 to 1989 and as a production engineer for Kerr-McGee Corporation from 1991 to 1994. Mr. Jordan is a member of the Society of Petroleum Engineers and graduated from Texas A & M University in 1984 and in 1990.

Stephen W. Miller
Vice President–Operations

Stephen W. Miller has served as Vice President – Operations since 1996 and served as District Manager – College Station District from 1994 to 1996. Mr. Miller held various engineering positions in the oil and gas industry from 1980 to 1993. Mr. Miller is a registered Professional Engineer in Texas, a member of the Society of Petroleum Engineers and graduated from Texas A & M University in 1980.

Michael A. Johnson
Vice President–Financial Reporting

Michael A. Johnson has served as Vice President – Financial Reporting since March 1998. From 1993 to March 1998, he served as Assistant Controller to the company. From 1991 to 1993, he served as project manager for Phibro Energy Production, Inc., a Russian joint venture. From 1987 to 1991, Mr. Johnson served as audit manager for Arthur Andersen & Co. Mr. Johnson is a Certified Public Accountant and graduated from the University of Texas in 1987.

Tony S. Say
President–Chesapeake Energy Marketing, Inc.

Tony S. Say has served as President of Chesapeake Energy Marketing, Inc. since 1995. In 1993, Mr. Say co-founded Princeton Natural Gas Company, which was purchased by Chesapeake Energy Corporation in 1995. From 1986 to 1993, Mr. Say was President and Chief Executive Officer of Clinton Gas Transmission, Inc., a company he co-founded and later sold to a major utility in 1993. From 1979 to 1986, Mr. Say was employed by Delhi Gas Pipeline Corporation. Mr. Say is a member of the Natural Gas Society of Oklahoma and the Natural Gas Society of North Texas, and graduated from the University of Oklahoma in 1979.

Janice A. Dobbs
Corporate Secretary and Compliance Manager

Janice A. Dobbs has served as Corporate Secretary and Compliance Manager since 1993. From 1975 until her association with the company, Ms. Dobbs was the corporate/securities legal assistant with the law firm of Andrews Davis Legg Bixler Milsten & Price, Inc. in Oklahoma City. From 1973 to 1975, Ms. Dobbs worked for Texas International Company, an oil and gas company in Oklahoma City. Ms. Dobbs is a Certified Legal Assistant, an associate member of the American Bar Association, a member of the American Society of Corporate Secretaries and a member of the Society of Human Resources Management.

The Chesapeake Team

Norvella Adams, Steve Adams, Richey Albright, Linda Allen, Sam Allen, Karla Allford, Eduardo Alvarez-Salazar, Amy Anderson, Heather Anderson, Mark Anderson, Colley Andrews, Joe Archuleta, Judy Arias-Sanchez, Paula Asher, Eric Ashmore, David Ault, Jack Austin, Barbara Bale, Marilyn Ball, Ralph Ball, Crae Barr, Francy Beesley, Michaela Benners, Joel Bennett, Leonard Berry Jr., Rodney Beverly, Calvin Bodin, Sandra Bogle, Ted Boismier, Randy Borlaug, Susan Bradford, Steve Brady, Wade Brawley, James Brinkley, Leslie Bross, Joe Brougher, Janice Brown, Mark Brown, Pamela Brown, Randy Brown, Debra Brummett, Lori Budde, Ruth Burba, Martha Burger, Karl Burkard, Steve Burns, Diane Busch, Shelli Butler, Kenneth Bynum, Lisa Calaway, Sara Caldwell, Terry Caldwell, Wendy Call, Robert Campbell, Sharon Campbell, Ted Campbell, Jesse Canaan, Donna Cardwell, Patti Carlisle, Leonardo Carmona, Martin Carmona-Cruz, Jamie Carter, Belinda Cathey, Ilan Cathey, Natasha Chamberlain, Sherri Childers, Sherry Childress-Walton, Ivajean Clark, Stephen Cody, Michael Coles, Gary Collings, Maria Constantino, Kristine Conway, Dale Cook Jr., Walter Cook, Randy Cornelsen, Lori Coryell, Frank Coshow, David Craycraft, Mary Crocker, Tiffany Cruce, Audra Cumings, Ken Davidson, Cheryl Davis, Jason Davis, Ted Davis, Kevin Decker, Casidy Denney, George Denny, Tim Denny, David DeSalvo, Alton Dickey, Lynn Diel, Bruce Dixon, Steve Dixon, Janice Dobbs, Eric Dodson, Jennifer Dorsey, Kim Doty, Stephen Douglas, Mac Drake, Greg Drwenski, Mandy Duane, Gary Dunlap, Don Dunn, Gary Egger, Heidi Einspahr, Steve Emick, Kyle Essmiller, Dan Estes, Mark Evans, Jan Fair, Jenny Ferguson, Lisa Finley, Gary Finn, Charles Floyd, Barbara Frailey, Joy Franklin, Billy Free, Sherry Freeman, Dennis Frick, Crystal Fuchs, Linda Gardner, Terry Garrison, Randy Gasaway, Steve Gaskins, Jeff Geis, Stacy Gilbert, Robert Gilkes, Kim Ginter, Debbie Glasgow, Charlene Glover, Randy Goben, Jim Gomez, Traci Gonzales, Pat Goode, Gena Goodwin, Dana Gordon, Marty Gore, Tony Gore, Amy Goss, Jimmy Gowens, Ranae Green, Tana Griggs, Jennifer Grigsby, Brian Gross, Melissa Gruenewald, Brian Guire, Dena Guthery, Eddie Hall, Cheryl Hamilton, Shane Hamilton, Kelsey Hammit, Tresa Hammond, Steve Hammons, Cliff Hanoch, Gayle Harris, Jeff Harris, Joey Harris, Jimmy Hayes, Michelle Hazlip, Mike Hazlip, Duane Heckelsberg, Robert Hefner IV, Larry Hesse, David Higgins, JoAnna Ho, Ladana Hodgin, Deborah Hoehne, Carol Holden, Henry Hood, Marilyn Hooser, Kenny Hopkins, Greg Horn, Michael Horn, Janice Horton, Yamei Hou, Christia Hudson, Eric Hughes, Fred Hughes, Jean Hughes, Richard Hughes, Ted Hulett, Marion Hunt, Brian Imes, Charles Imes, Kim Imes, Kimberly Jacks, Kristie Jacob, Lorrie Jacobs, Eugene James, Doug Johnson, Jim Johnson, Mike Johnson, Lee Johnston, Mike Johnston, David Jones, David W. Jones, Johnny Jones, Frank Jordan, Susan Keller, Tammy Kelln, Taylor Kemp, Phyllis Kimray, Stephen King, Terry Kite, Darvin Knapp, Dana Knaub, Greg Knight, Ted Krigbaum, Wesley Kruckenberg, Sandi Lagaly, Michael Lancaster, Gwen Lang, Barry Langham, Kim Laughlin, Cindy LeBlanc, Dan LeDonne, Mike Lebsack, Chris Lee, Randy Lee, Ron Lefaive, Steve Lepretre, Mark Lester, Carrie Lewis-Crawford, Kimberly Louthan, Kinney Louthan, Janet Lowrey, Michael Ludlow, Sarah Lumen, Larry Lunardi, Craig Madsen, Troy Mahan, Felipe Maldonado, John Marks, Tim Marnich, John Marshall, Chris Martin, Kim Massey, Sandy Mathis, Allen May, Sam McCaskill, Aubrey McClendon, Joe McClendon, Carrol McCoy, Matt McCreary, Dennis McGee, Janelle McNeely, Sondra McNeiland, Carl McSpadden, Dorina Meihls, Hue Miller, Steve Miller, William Miller, Carey Milligan, Laura Minter, David Mobley, Linda Mollman, Sonya Monica, Deborah Morgan, Tommy Morphew, James Morton, Michelle Munnerlyn, Pat Murano, Eric Murray, Leland Murray, Liz Muskrat, Wes Myers, Tara Nash, Robert Neely, Ira Neff Jr., Jay Newton, Tammy Nguyen, Stafona Nichols, Buddy Novak, Jonna Nowakowski, Kathryn Nowlin, Lejeia Nunley, Gerda Oliver, Raymond Osborn, Edward Oursler, Lisa Owens, Donald Pannell, Michael Park, Carol Passick, Amy Patel, Gary Payne, Armando Pena, Robert Perkins II, Linda Peterburs, Dale Petty, Barbie Phelps, Ty Phoenix, Randy Pierce, Bob Pope, Pat Pope, Erick Porter, Bobby Portillo, Fernando Portillo, Angela Ports, Robert Potts, Buddy Powell Jr., Heather Preston, Tom Price Jr., Wayne Psencik, Thomas Putz, John Qualls, Lori Ray, Deborah Reichert, Aaron Reyna, Deborah Richardson, Christie Rickey, Brandy Riley, Carole Robinson, William Robinson, Matthew Rockers, Les Rodman, Lawrence Rogers, Pat Rolla, Janna Rothwell, Ray Roush, Marc Rowland, Robert Rowley, Kelly Ruminer, Beth Russ, Danny Rutledge, Bryan Sagebiel, Rose Sales, Tony Say, John Schartz, Hank Scheel, Patti Schlegel, Charles Scholz, Bonnie Schomp, Kurt Schrantz, Delores Schreiber, Jolene Schur, Daniel Scott, Ricky Scruggs, Cheryl Self, David Sellers, Stephanie Shedden, Ellen Short, Arlene Shuman, Carolyn Simmons, Shirley Skelton-Blass, Greg Small, April Smith, Charles Smith, Jason Smith, Sylvia Smith, Vivian Smith, Wilma Smith, Paige Snider, James Snyder, William Snyder, Antonio Soto, George Soto, Daniel Sparks, Krysta Starkey, Linda Steen, Stan Stinnett, Liz Stranczek, Brenda Stremble, John Striplin, Dani Stuart, Randy Summers, Iris Tadlock, Candice Taylor, Wesley Tayrien, Rebecca Thomas, Terri Thomas, Jennifer Thompson, Rachel Thompson, Lynda Townsend, John Tracy, Connie Turner, Kenneth Turner, Jimmie Turnpaugh, Guy Unger, Frank Unsicker, Amy Van Brunt, Jennifer Van Meir, Shelby VanWinkle, Joe Vaughan, Melissa Verett, Peggy Vosika, Brent Voto, Kay Vuong, Bill Wagner, James Walck, Allan Waldroup, Robert Walker, Ronnie Walker, Ronnie Ward, Tom Ward, Julie Washam, Patsy Watters, Melanie Weaver, Janet Weeks, Lance Weihs, Greg Weinschenk, Lu Ann Wernli, Amanda Whipple, Dennis Whipple, James Whipple, Craig White, Shelly White, Mary Whitson, Tony Wildman, Ken Will, Cindi Williams, Dori Williams, Jeff Williams, Sincerria Williams, Curtis Williford, Tina Willingham, Durell Willoughby, Julie Wilmoth, Brian Winter, Lon Winton, David Wittman, Heidi Wolfinbarger, Jimmy Wright, Tobin Yocham, Alan Zeiler, Gerald Zgabay

Glossary of Terms

Bcf Billion cubic feet of natural gas.

Bcfe Billion cubic feet of natural 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.

Ceiling Test Writedown A non-cash charge to earnings mandated by the Securities and Exchange Commission for companies utilizing the full-cost method of accounting. Under the full-cost method of accounting, all costs of acquisition, exploration and development of oil and gas reserves are capitalized into a "full-cost pool," and properties in the pool are depleted and charged to operations using the unit-of-production method based on the ratio of current production to total proved oil and gas reserves. To the extent that such capitalized costs (net of accumulated depreciation, depletion and amortization) less deferred taxes exceed the present value (discounted at 10%) of estimated future net cash flows from proved oil and gas reserves and the lower of cost or fair value of unproved properties after income tax effects, the excess is charged to operations in the current period. However, such charges do not have an impact on cash flows from operating activities. Once incurred, a writedown of oil and gas properties is not reversible, even if oil and gas prices subsequently increase.

Commingled Well A well producing from two or more formations through a common well casing and a single tubing string.

DD&A Depreciation, depletion and amortization.

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.

Downdip Wells Wells producing from deeper depths lower on a structure than updip wells.

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

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

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.

Finding Costs The capital costs associated with finding and developing oil and gas reserves.

Formation An identifiable single geologic horizon.

Fracture Stimulation Action taken to increase the inherent productivity of a prospective formation through the hydraulic injection of water, diesel or CO2 at high rates.

G&A Expenses General and administrative expenses.

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

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

Increased Density A well drilled in addition to the number of wells permitted under normal spacing regulations to accelerate recovery or prevent loss of reserves.

Independent Producer A nonintegrated producer of oil and gas with no refining or retail marketing operations.

Lease Operating Expenses (LOE) The costs of maintaining and operating property and equipment on a producing oil and gas lease.

MBbls One thousand barrels of oil.

Mcf One thousand cubic feet of natural gas.

MMcf One million cubic feet of natural gas.

MMcfe One million cubic feet of natural gas equivalent; a unit of measurement which combines oil, natural gas liquids, and natural gas. Oil and natural gas liquids are converted to natural gas based upon their relative energy content at the rate of 6 mcf for each barrel of oil or natural gas liquids.

Operating Costs The sum of lease operating costs, production taxes and G&A expenses.

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

Payzone The producing formation(s) of a well.

Present Value When used with respect to oil and gas reserves, present value is 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 natural 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 a known reservoir(s) on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Reserve Life The term in years required to deplete the company's proved oil and gas reserve base at current production rates.

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.

3-D Seismic Advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

Tcf One trillion cubic feet of natural gas.

Tcfe One trillion cubic feet of natural 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.

With the number of asset impairment charges incurred by the company over the past two years as oil and natural gas prices have declined and the company sharply reduced its Louisiana Austin Chalk drilling program, many investors have inquired about the different oil and gas accounting methods and rules that affect energy producers. The following provides some explanation of the related issues.

Full-cost versus successful-efforts accounting
Oil and gas companies are allowed to use either of two accounting methods – full cost or successful efforts. Although both methods follow the accounting principles of matching, realization, and cost, they differ materially on how impairments are caused.

Impairments, or the writedown in value of oil and gas properties, are principally caused by temporary downturns in oil and gas prices which significantly reduce reserve values because the SEC requires a company to value its reserve base using end-of-quarter prices in lieu of historical averages, future expectations or other concepts that attempt to capture the intrinsic long-term value of a company's reserves. Under full-cost accounting, impairment charges against the book value of oil and gas assets are typically larger and more frequent than under successful-efforts accounting largely due to the requirement that full-cost companies use the discounted (at 10%) stream of future revenue to compare against the book value of the properties. Successful-efforts companies, on the other hand, are not subject to the same requirement to discount the future revenue stream. The difference in the two methods is magnified when applied to assets with especially long expected production lives. In cases of extremely long-lived properties (productive lives of more than 40 years such as Chesapeake's Hugoton Field and West Panhandle Field assets), as much as 50% of the total reserves may be determined uneconomic at today's constant, discounted prices and are thus eliminated from the reserve report in spite of their substantial future value.

Furthermore, in addition to the adverse income statement impact caused by the impairment charges, a producer's balance sheet is similarly negatively affected. The category of Stockholders' Equity is permanently reduced in periods of low prices, but is not revised upward when prices increase. Another peculiar result is the reappearance of "phantom" reserves in future years. These are reserves that are deducted from the reserve report when prices are unfavorable but are added back to the reserve report when prices become more favorable. The overall existence of the physical reserves does not change, but the economic viability of the reserves can come and go. An important mitigating benefit of the impairments is that future earnings are enhanced because future depreciation rates are lower than they would have been without the writedowns.

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 1998

[ ] 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 26, 1999 was $103,439,199. At such date, there were 96,720,308 shares of Common Stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 1999 annual meeting of shareholders are incorporated by reference in Part III

PART I

ITEM 1. *Business*

General

Chesapeake Energy Corporation ("Chesapeake" or the "Company") is an independent oil and gas company primarily engaged in the exploration, acquisition, development and production of onshore natural gas reserves in the United States and Canada. Chesapeake began operations in 1989, completed an initial public offering in 1993, and trades on the New York Stock Exchange under the symbol CHK. The Company's principal offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118 (telephone 405/848-8000).

Chesapeake currently owns interests in approximately 5,300 producing oil and gas wells concentrated in three primary operating areas: the Mid-Continent region consisting of Oklahoma, southwestern Kansas and the Texas Panhandle; the Gulf Coast region consisting primarily of the Austin Chalk Trend in Texas and Louisiana and the Tuscaloosa Trend in Louisiana; and the Helmet area of northeastern British Columbia. During 1998 the Company produced 130.3 Bcfe, of which 72% was natural gas, making Chesapeake one of the top 20 public independent oil and gas companies in the United States as measured by production.

The following table sets forth the Company's estimated proved reserves, the related present value (discounted at 10%) of the proved reserves (based on weighted average prices at December 31, 1998 of $10.48 per barrel of oil and $1.68 per Mcf of gas), and the estimated capital expenditures required to develop the Company's proved undeveloped reserves at December 31, 1998:

	Oil (MBbl)	Gas (MMcf)	Gas Equivalent (MMcfe)	Percent of Proved Reserves	Present Value (Disc. @10%) ($ in 000's)	Estimated CapEx to Develop PUD's ($ in 000's)
Mid-Continent	11,009	558,754	624,811	57%	$347,937	$ 72,398
Canada	33	231,773	231,969	21	156,843	28,298
Gulf Coast	3,836	128,419	151,434	14	111,135	34,120
Other areas	7,715	36,845	83,134	8	45,076	9,674
Total	22,593	955,791	1,091,348	100%	$660,991	$144,490

From inception through mid-1997, Chesapeake's primary business strategy was growth through the drillbit. In 1997, however, disappointing drilling results in the Louisiana Austin Chalk Trend, combined with the industry's rapidly escalating drilling costs and falling oil prices, caused management to change the Company's business strategy. As a result of this change, in late 1997 and 1998 the Company significantly reduced its capital expenditures for exploration drilling and acreage acquisition and focused on the acquisition of long-lived natural gas properties in the Mid-Continent and Canada that contain numerous low risk development opportunities. During 1998, the Company acquired approximately 750 Bcfe primarily in eight separate transactions. The total consideration given for the acquisitions was 30.8 million shares of Company common stock, $280 million in cash, the assumption of $205 million in debt, and the incurrence of approximately $20 million of other acquisition related costs.

The oil and gas industry is characterized by volatile product prices. During late 1998, inflation-adjusted prices for oil reached lows not seen in 50 years. Also, a second consecutive mild winter and the resulting high inventory of natural gas in storage have caused gas prices to fall. These low oil and gas prices, combined with the Company's high level of indebtedness, have caused the Company to focus on decreasing operating and general and administrative costs and reducing drilling capital expenditures to a level that can be financed from operating cash flow, including proceeds from the sale of non-core, low-value oil properties. The Company's strategy for 1999 is to maintain appropriate liquidity levels while concentrating on further developing its core natural gas assets.

Drilling Activity

The following table sets forth the wells drilled by the Company during the periods indicated. In the table, "gross" refers to the total wells in which the Company has a working interest and "net" refers to gross wells multiplied by the Company's working interest therein.

	Year Ended December 31, 1998		Six Months Ended December 31, 1997		Year Ended June 30, 1997		Year Ended June 30, 1996	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development:								
Productive	169	97.5	55	24.4	90	55.0	111	49.5
Non-productive	10	5.1	1	0.3	2	0.2	4	1.6
Total	179	102.6	56	24.7	92	55.2	115	51.1
Exploratory:								
Productive	47	23.7	28	15.5	71	46.1	29	16.5
Non-productive	16	8.9	2	0.9	8	5.7	4	1.4
Total	63	32.6	30	16.4	79	51.8	33	17.9

Included in the above table for 1998, the Company drilled 11 (3.6 net) productive development wells and one (0.4 net) non-productive development wells in Canada. Also during 1998, the Company drilled one (0.3 net) productive exploratory wells and seven (2.1 net) non-productive exploratory wells in Canada.

Well Data

At December 31, 1998, the Company had interests in 5,304 (2,405 net) producing wells, of which 219 (96 net) were classified as primarily oil producing wells and 5,085 (2,309 net) were classified as primarily gas producing wells.

Volumes, Revenue, Prices and Production Costs

The following table sets forth certain information regarding the production volumes, revenue, average prices received and average production costs associated with the Company's sale of oil and gas for the periods indicated:

	Year Ended December 31, 1998	Six Months Ended December 31, 1997	Year Ended June 30, 1997	Year Ended June 30, 1996
Net production:				
Oil (MBbl)	5,976	1,857	2,770	1,413
Gas (MMcf)	94,421	27,326	62,005	51,710
Gas equivalent (MMcfe)	130,277	38,468	78,625	60,190
Oil and gas sales ($ in 000's):				
Oil	$ 75,877	$ 34,523	$ 57,974	$ 25,224
Gas	181,010	61,134	134,946	85,625
Total oil and gas sales	$ 256,887	$ 95,657	$ 192,920	$ 110,849
Average sales price:				
Oil ($ per Bbl)	$ 12.70	$ 18.59	$ 20.93	$ 17.85
Gas ($ per Mcf)	$ 1.92	$ 2.24	$ 2.18	$ 1.66
Gas equivalent ($ per Mcfe)	$ 1.97	$ 2.49	$ 2.45	$ 1.84
Oil and gas costs ($ per Mcfe):				
Production expenses and taxes	$ .45	$ .27	$ .19	$ .14
General and administrative	$ .15	$ .15	$ .11	$ .08
Depreciation, depletion and amortization of oil and gas properties	$ 1.13	$ 1.57	$ 1.31	$ .85

Included in the above table are the results of Canadian operations during 1998. The average sales price for the Company's Canadian gas production was $1.03 during 1998 and the Canadian production expenses and taxes were $0.24 per Mcf.

Development, Exploration and Acquisition Expenditures

The following table sets forth certain information regarding the costs incurred by the Company in its development, exploration and acquisition activities during the periods indicated:

	Year Ended December 31, 1998	Six Months Ended December 31, 1997	Year Ended June 30, 1997	Year Ended June 30, 1996
		($ in thousands)		
Development costs	$ 150,537	$ 120,628	$ 187,736	$ 138,188
Exploration costs	68,672	40,534	136,473	39,410
Acquisition costs:				
Unproved properties	26,369	25,516	140,348	138,188
Proved properties	740,280	39,245	—	24,560
Sales of oil and gas properties	(15,712)	—	—	—
Capitalized internal costs	5,262	2,435	3,905	1,699
Proceeds from sale of leasehold, equipment and other	(296)	(1,861)	(3,095)	(6,167)
Total	$ 975,112	$ 226,497	$ 465,367	$ 335,878

Acreage

The following table sets forth as of December 31, 1998 the gross and net acres of both developed and undeveloped oil and gas leases which the Company holds. "Gross" acres are the total number of acres in which the Company owns a working interest. "Net" acres refer to gross acres multiplied by the Company's fractional working interest. Acreage numbers are stated in thousands and do not include options for additional leasehold held by the Company, but not yet exercised.

	Developed		Undeveloped		Total Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	1,576	621	835	304	2,411	925
Gulf Coast	451	280	1,333	1,084	1,784	1,364
Canada	82	32	569	233	651	265
Other areas	60	30	1,134	683	1,194	713
Total	2,169	963	3,871	2,304	6,040	3,267

Marketing

The Company's oil production is sold under market sensitive or spot price contracts. The Company's natural gas production is sold to purchasers under varying percentage-of-proceeds and percentage-of-index contracts. By the terms of these contracts, the Company receives a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after gathering and processing the Company's gas. The residue gas and natural gas liquids sold by these purchasers are sold primarily based on spot market prices. The revenue received by the Company from the sale of natural gas liquids is included in natural gas sales. During 1998, the following two customers individually accounted for 10% or more of the Company's total oil and gas sales:

	Amount ($ in thousands)	Percent of Oil and Gas Sales
Koch Oil Company	$ 30,564	12%
Aquila Southwest Pipeline Corporation	$ 28,946	11%

Management believes that the loss of either of the above customers would not have a material adverse effect on the Company's results of operations or its financial position.

Chesapeake Energy Marketing, Inc. ("CEMI"), a wholly-owned subsidiary, provides oil and natural gas marketing services, including commodity price structuring, contract administration and nomination services for the Company, its partners and other oil and natural gas producers in geographical areas in which the Company is active.

Hedging Activities

Periodically the Company utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include (i) swap arrangements that establish an index-related price above which the Company pays the counterparty and below which the Company is paid by the counterparty, (ii) the purchase of index-related puts that provide for a "floor" price below which the counterparty pays the Company the amount by which the price of the commodity is below the contracted floor, (iii) the sale of index-related calls that provide for a "ceiling" price above which the Company pays the counterparty the amount by which the price of the commodity is above the contracted ceiling, and (iv) basis protection swaps, which are arrangements that guarantee the price differential of oil or gas from a specified delivery point or points. Results from commodity hedging transactions are reflected in oil and gas sales to the extent related to the Company's oil and gas production. The Company only enters into commodity hedging transactions related to the Company's oil and gas production volumes or CEMI's physical purchase or sale commitments. 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, 1998, the Company had the following natural gas swap arrangements designed to hedge a portion of the Company's domestic gas production for periods after December 1998:

Months	Volume (MMBtu)	NYMEX-Index Strike Price (per MMBtu)
February 1999	4,300,000	$1.968
March 1999	4,600,000	1.968
April 1999	4,500,000	1.968
May 1999	4,600,000	1.968
June 1999	1,200,000	1.950
July 1999	1,240,000	1.950
August 1999	1,240,000	1.950
September 1999	1,200,000	1.950

During 1998, the Company closed transactions for natural gas previously hedged for the period April 1999 through November 1999 for net proceeds of $0.5 million.

Subsequent to December 31, 1998, the Company entered into additional natural gas swap arrangements for 6,100,000 MMBtu at a strike price of $1.875 for the period from June 1999 through September 1999. Such swap arrangements, along with those listed above and other miscellaneous transactions, were closed as of March 15, 1999, resulting in net proceeds of $4.7 million.

As of December 31, 1998, the Company had the following natural gas swap arrangements designed to hedge a portion of the Company's Canadian gas production for periods after December 1998:

Months	Volume (MMBtu)	Index-Strike Price (per MMBtu)
January 1999	589,000	$1.60
February 1999	532,000	1.60
March 1999	589,000	1.60
April 1999	570,000	1.60
May 1999	589,000	1.60
June 1999	570,000	1.60
July 1999	589,000	1.60
August 1999	589,000	1.60
September 1999	570,000	1.60

If the swap arrangements listed above had been settled on December 31, 1998, the Company would have incurred a loss of $0.8 million.

As of December 31, 1998, the Company had the following oil swap arrangements for periods after December 1998:

Months	Monthly Volume (Bbls)	NYMEX Heating Oil Minus NYMEX Crude Oil Index Strike Price (per Bbl)
January 1999	217,000	$ 2.957
February 1999	196,000	2.957
March 1999	155,000	2.900

If the swap arrangements listed above had been settled on December 31, 1998, the Company would have incurred a loss of $0.2 million. Subsequent to December 31, 1998, the Company settled the swap arrangements listed above for the periods of January 1999 and February 1999 resulting in a $0.4 million loss.

In addition to commodity hedging transactions related to the Company's oil and gas production, CEMI periodically enters into various hedging transactions designed to hedge against physical purchase and sale commitments made by CEMI. 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.

The Company also utilizes hedging strategies to manage fixed-interest rate exposure. Through the use of a swap arrangement, the Company believes it can benefit from stable or falling interest rates and reduce its current interest expense. For the year ended December 31, 1998, the Company's interest rate swap resulted in a $0.7 million reduction of interest expense.

Risk Factors

Substantial Debt Levels Could Affect Operations.

As of December 31, 1998, we had long-term indebtedness of $920 million and short-term bank indebtedness of $25 million. Additionally, the Company had a working capital deficit of $13 million and stockholders' equity was a deficit of $249 million. Our ability to meet our debt service requirements throughout the life of the senior notes and our ability to meet our preferred stock obligations will depend on our future performance, which will be subject to oil and gas prices, our production levels of oil and gas, general economic conditions, and financial, business and other factors affecting our operations. Our level of indebtedness may have the following effects on our future operations:

- a substantial portion of our cash flow from operations may be dedicated to the payment of interest on indebtedness and will not be available for other purposes,
- restrictions in our debt instruments limit our ability to borrow additional funds or to dispose of assets and may affect our flexibility in planning for, and reacting to, changes in the energy industry, and
- our ability to obtain additional capital in the future may be impaired.

The short-term indebtedness described above was incurred under our commercial bank facility which matures in August 1999. Although we believe this facility will be renewed, we can offer no assurances that we will be able to renew the bank facility on favorable terms. As a result of our high level of indebtedness and poor conditions in the energy industry, Standard & Poor's Corporation and Moody's Investors Service, in late 1998, reduced the credit ratings on our senior notes to "B" and "B3", respectively. These ratings remain under credit review with negative implications. Low credit ratings could negatively impact our ability to access capital markets.

The Volatility of Oil and Gas Prices Creates Uncertainties.

Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our oil and gas. Historically, the markets for oil and gas have been volatile and may continue to be volatile in the future. Various factors which are beyond our control will affect prices of oil and gas. These factors include:

- worldwide and domestic supplies of oil and gas,
- 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,
- the price and level of foreign imports,
- the level of consumer demand,
- the price and availability of alternative fuels,
- the availability of pipeline capacity,
- weather conditions, and
- domestic and foreign governmental regulations and taxes.

We are unable to predict the long-term effects of these and other conditions on the prices of oil and gas. Lower oil and gas prices may reduce the amount of oil and gas we produce, which may adversely affect our revenues and operating income. Because our 1999 business strategy is to generally match our capital expenditures for drilling activities to cash flow from operations, significant reductions in oil and gas prices may require us to reduce our capital expenditures. Reducing drilling will make it more difficult for us to replace the reserves we produce.

We Must Replace Reserves to Sustain Production.

As is customary in the oil and gas exploration and production industry, 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. Approximately 30% by volume, or 22% by value, of our total estimated proved reserves at December 31, 1998 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 that the Company can successfully find and produce reserves economically in the future.

Significant Capital Expenditures Will be Required to Exploit Reserves.

We have made and intend to make substantial capital expenditures in connection with the exploration, development and production of our oil and gas properties. Historically, we have funded our capital expenditures through a combination of internally generated funds, equity issuances and long-term debt financing arrangements and sale of non-core assets. From time to time, we have used short-term bank debt, generally as a working capital facility. 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 and in selling non-core assets. 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 debt or equity financing will be available to meet these requirements.

We May Have Additional Full-Cost Ceiling Writedowns if Oil and Gas Prices Decline Further or if Drilling Results are Unfavorable.

The Company reported full-cost ceiling writedowns of $826 million, $110 million, and $236 million during the year ended December 31, 1998, the six month transition period ended December 31, 1997 (the "Transition Period"), and the fiscal year ended June 30, 1997, respectively. These writedowns were caused by significant declines in oil and gas prices during all three periods and by poor drilling results in 1997 and during the Transition Period.

Additionally, significant declines in prices can cause proved undeveloped reserves to become uneconomic, and long-lived production to become "economically truncated", further reducing proved reserves and increasing any writedown. Such economic truncation resulted in the Company's reserves being approximately 100 Bcfe less at December 31, 1998 than they would have been using pricing in effect as of December 31, 1997. The Company's reserve values were calculated using weighted average prices at December 31, 1998 of $10.48 per barrel of oil and $1.68 per Mcf of natural gas. If prices in future periods are below the prices used at December 31, 1998, future impairment charges will likely be incurred. Although the Company has taken steps to reduce drilling risk, reduce operating costs, and reduce investment in unproved leasehold, these steps may not be sufficient to enhance future economic results or prevent additional leasehold impairment and full-cost ceiling writedowns, which are highly dependent on future oil and gas prices.

Drilling and Oil and Gas Operations Present Unique Risks.

Drilling activities are subject to many risks, including well blowouts, cratering, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pollution, releases of toxic gases and other environmental hazards and risk, any of which could result in substantial losses. In addition, we incur the risk that we will not encounter any commercially productive reservoirs through our drilling operations. We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our investment in wells drilled. Drilling for oil and gas may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs.

Existing Debt Covenants Restrict Our Operations.

The indentures which govern our long-term debt contain covenants which restrict our ability, and the ability of our subsidiaries other than CEMI, to engage in the following activities:

- incurring additional debt,
- creating liens,
- paying dividends and making other restricted payments,
- merging or consolidating with any other entity,
- selling, assigning, transferring, leasing or otherwise disposing of all or substantially all of our assets, and
- guaranteeing any indebtedness.

At December 31, 1998, the Company did not meet a debt incurrence test contained in two of the senior note indentures. Thus, we will be unable to incur unsecured non-bank debt until there is significant improvement in oil and gas prices and/or our production levels. Additionally, the Company will not be able to resume the payment of dividends on its common and preferred stock until it meets the debt incurrence test.

Canadian Operations Present the Risks Associated with Conducting Business Outside the U.S.

A portion of our business is conducted in Canada. You may review the amounts of revenue, operating losses and identifiable assets attributable to our Canadian operations in Note 8 of the Notes to Consolidated Financial Statements in Item 8. Also, Note 11 of the Consolidated Financial Statements provides disclosures about our Canadian oil and gas producing activities. Our operations in Canada are subject to the risks associated with operating outside of the United States. 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 United States court.

Pending Legal Proceedings Could Have a Material Adverse Effect.

The Company is a defendant in two purported class actions based on federal and state securities fraud claims. In addition, we are defending claims of patent infringement in another pending action. While no prediction can be made as to the outcome of these matters or the amount of damages that might be awarded, if any, an adverse result in any of them could be material to our financial results. See Item 3. Legal Proceedings.

The Loss of Either the CEO or the COO Could Adversely Affect Operations.

Our operations are dependent upon our Chief Executive Officer, Aubrey K. McClendon, and our Chief Operating Officer, Tom L. Ward. The unexpected loss of the services of either of these executive officers could have a detrimental effect on our operations. The Company maintains $20 million key man life insurance policies on the life of each of Messrs. McClendon and Ward.

Transactions with Executive Officers May Create Conflicts of Interest.

Messrs. McClendon and Ward have rights to participate in wells we drill during any succeeding quarter, and they participated in every well we have drilled through December 31, 1998. As a result of their participation, they routinely have significant accounts payable to the Company for joint interest billings. As of December 31, 1998, Messrs. McClendon and Ward had payables to the Company of $2.8 million and $2.4 million, respectively, in connection with such participation. Additionally, Messrs. McClendon and Ward have loans due on December 31, 1999 to CEMI in the principal amounts of $4.9 million and $5.0 million (as of December 31, 1998), respectively. Such loans, which were first made in July 1998, are collateralized and carry an annual interest rate of 9.125%. As of March 30, 1999, Messrs. McClendon's and Ward's loans have been reduced to $4.3 million and $4.6 million, respectively. The existence of these loans and the rights to participate in wells we drill could present a conflict of interest with respect to Messrs. McClendon and Ward.

The Ownership of a Significant Percentage of Stock by Insiders Could Influence the Outcome of Shareholder Votes.

At March 26, 1999, our Board of Directors and senior management beneficially owned an aggregate of 27,923,997 shares of common stock (including outstanding vested options), which represented approximately 28% of our outstanding shares. The ownership of Messrs. McClendon and Ward and their children's trusts accounted for 25% of the outstanding common stock. As a result, Messrs. McClendon and Ward, together with other officers and directors of the Company, are in a position to significantly influence matters requiring the vote or consent of our shareholders.

The Company Could be Adversely Affected if Our Computer Systems or Those of Our Vendors Are Not Year 2000 Compliant.

Year 2000 issues exist when dates are recorded in computers using two digits, rather than four, and are then used for arithmetic operations, comparisons or sorting. A two-digit recording may recognize a date using "00" as 1900 rather than 2000, which could cause our computer systems to perform inaccurate computations. Year 2000 issues relate not only to our systems, but also to those used by our suppliers. We anticipate that system replacements and modifications will resolve any Year 2000 issues that may exist with our suppliers or their suppliers. However, we cannot guarantee that such replacements or modifications will be completed successfully or on time and, as a result, any failure to complete such modifications on time could materially affect our financial and operating results in a negative way. Please read the additional discussion regarding the Year 2000 issue and the potential impact on our business in the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations – Year 2000" later in this Form 10-K for additional information.

Regulation

General

Numerous departments and agencies, 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. The regulatory burden on the oil and gas industry increases the Company's cost of doing business and, consequently, affects its profitability.

Exploration and Production

The Company's operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used or obtained in connection with operations. The Company's operations are also subject to various conservation regulations. These include the regulation of the size of drilling and spacing units and the density of wells which may be drilled 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 develop a prospect 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 the Company can produce from its wells and to limit the number of wells or the locations at which the Company can drill. The extent of any impact on the Company of such restrictions cannot be predicted.

Environmental and Occupational Regulation

General. The Company's activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. It is anticipated that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations concerning the protection of the environment and human health will not have a material effect upon the operations, capital expenditures, earnings or the competitive position of the Company. The Company cannot predict what effect additional regulation or legislation, enforcement policies thereunder and claims for damages for injuries to property, employees, other persons and the environment resulting from the Company's operations could have on its activities.

Activities of the Company with respect to the exploration, development and production of oil and natural gas are subject to stringent environmental regulation by state and federal authorities including the United States Environmental Protection Agency ("EPA"). Such regulation has increased the cost of planning, designing, drilling, operating and in some instances, abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products and waste created by water and air pollution control procedures. Although the Company believes that compliance with environmental regulations will not have a material adverse effect on operations or earnings, risks of substantial costs and liabilities are inherent in oil and gas operations, and there can be no assurance that significant costs and liabilities, including criminal penalties, will not be incurred. Moreover, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages for injuries to property or persons resulting from the Company's operations could result in substantial costs and liabilities.

Waste Disposal. The Company currently owns or leases, and has in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although the

Company has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under the Company's control. State and federal laws applicable to oil and natural gas wastes and properties have gradually become more strict. Under such laws, the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

The Company generates wastes, including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA and various state agencies have limited the disposal options for certain hazardous and nonhazardous wastes and are considering the adoption of stricter disposal standards for nonhazardous wastes. Furthermore, certain wastes generated by the Company's 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.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the owner and operator of a site and persons that disposed of or arranged for the disposal of the hazardous substances found at a site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from responsible classes of persons the costs of such action. In the course of its operations, the Company may have generated and may generate wastes that fall within CERCLA's definition of "hazardous substances". The Company may also be or have been an owner of sites on which "hazardous substances" have been released. The Company may be responsible under CERCLA for all or part of the costs to clean up sites at which such wastes have been released. To date, however, neither the Company nor, to its knowledge, its predecessors or successors have been named a potentially responsible party under CERCLA or similar state superfund laws affecting property owned or leased by the Company.

Air Emissions. The operations of the Company are subject to local, state and federal regulations for the control of emissions of air pollution. Legal and regulatory requirements in this area are increasing, and there can be no assurance that significant costs and liabilities will not be incurred in the future as a result of new regulatory developments. In particular, regulations promulgated under the Clean Air Act Amendments of 1990 may impose additional compliance requirements that could affect the Company's operations. However, it is impossible to predict accurately the effect, if any, of the Clean Air Act Amendments on the Company at this time. The Company may in the future be subject to civil or administrative enforcement actions for failure to comply strictly with air regulations or permits. These enforcement actions are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require the Company to forego construction or operation of certain air emission sources.

OSHA. The Company is subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and similar state statutes require the Company to organize information about hazardous materials used, released or produced in its operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens. The Company is also subject to the requirements and reporting set forth in OSHA workplace standards. The Company provides safety training and personal protective equipment to its employees.

OPA and Clean Water Act. Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as the Company, to prepare and implement spill prevention control plans, countermeasure plans and facilities response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") amends certain provisions of the federal Water Pollution Control Act of 1972, commonly referred to as the Clean Water Act ("CWA"), and other statutes as they pertain to the prevention of and response to oil spills into navigable waters. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. The CWA provides penalties for any discharges of petroleum product in reportable quantities and imposes substantial liability for the costs of removing a spill. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of releases of petroleum or its derivatives into surface waters or into the ground. Regulations are currently being developed under OPA and state laws concerning oil pollution prevention and other matters that may impose additional regulatory burdens on the Company. In addition, the CWA and analogous state laws require permits to be obtained to authorize discharges into surface waters or to construct facilities in wetland areas. With respect to certain of its operations, the Company is required to maintain such permits or meet general permit requirements. The EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, participate in a group permit or seek coverage under an EPA general permit. The Company believes that with respect to existing properties it has obtained, or is included under, such permits and with respect to future operations it will be able to obtain, or be included under, such permits, where necessary. Compliance with such permits is not expected to have a material effect on the Company.

NORM. Oil and gas exploration and production activities have been identified as generators of concentrations of low-level naturally-occurring radioactive materials ("NORM"). NORM regulations have recently been adopted in several states. The Company is unable to estimate the effect of these regulations, although based upon the Company's preliminary analysis to date, the Company does not believe that its compliance with such regulations will have a material adverse effect on its operations or financial condition.

Safe Drinking Water Act. The Company's operations involve the disposal of produced saltwater and other nonhazardous oilfield wastes by reinjection into the subsurface. Under the Safe Drinking Water Act ("SDWA"), oil and gas operators, such as the Company, must obtain a permit for the construction and operation of underground Class II injection wells. To protect against contamination of drinking water, periodic mechanical integrity tests are often required to be performed by the well operator. The Company has obtained such permits for the Class II wells it operates. The Company also has disposed of wastes in facilities other than those owned by the Company which are commercial Class II injection wells.

Toxic Substances Control Act. The Toxic Substances Control Act ("TSCA") was enacted to control the adverse effects of newly manufactured and existing chemical substances. Under the TSCA, the EPA has issued specific rules and regulations governing the use, labeling, maintenance, removal from service and disposal of PCB items, such as transformers and capacitors used by oil and gas companies. The Company may own such PCB items but does not believe compliance with TSCA has or will have a material adverse effect on the Company's operations or financial condition.

Title to Properties

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, the Company's title to oil and gas properties is challenged through legal proceedings. The Company is routinely involved in litigation involving title to certain of its oil and gas properties, none of which management believes will be materially adverse to the Company, individually or in the aggregate.

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 the Company 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. The Company's horizontal and Deep Tuscaloosa drilling activities involve greater risk of mechanical problems than conventional vertical drilling operations.

The Company maintains a $50 million oil and gas lease operator policy that insures the Company against certain sudden and accidental risks associated with drilling, completing and operating its wells. There can be no assurance that this insurance will be adequate to cover any losses or exposure to liability. The Company also carries comprehensive general liability policies and a $60 million umbrella policy. The Company and its subsidiaries carry workers' compensation insurance in all states in which they operate and a $35 million employment practice liability policy. While the Company believes these policies are customary in the industry, they do not provide complete coverage against all operating risks.

Employees

The Company had 481 full-time employees as of December 31, 1998 and reduced this level to 453 as of March 15, 1999. No employees are represented by organized labor unions. The Company considers its employee relations to be good.

Facilities

The Company owns 13 buildings totaling approximately 86,500 square feet and nine acres of land in an office complex in Oklahoma City that comprise its headquarters' offices. The Company also owns field offices in Lindsay, Waynoka and Weatherford, Oklahoma and leases office space in Garden City, Hays and Wichita, Kansas; Oklahoma City, Oklahoma; Big Lake, College Station, Fritch and Navasota, Texas; Lafayette, Louisiana; and in Calgary, Alberta, Canada. The offices in Garden City, Wichita, College Station and Lafayette have been or will be closed in the near future and the space sub-leased or terminated.

Glossary

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of gas equivalent.

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

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

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

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

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

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

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

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

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

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

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

Horizontal Wells. Wells which are drilled at angles greater than 70 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.

Present Value. When used with respect to oil and gas reserves, present value 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*

Primary Operating Areas

The Company's strategy is to focus its acquisition and development efforts in three areas: (i) the Mid-Continent (consisting of Oklahoma, southwestern Kansas and the Texas Panhandle), (ii) the onshore Gulf Coast in Texas and Louisiana, and (iii) the Helmet area in northeastern British Columbia. In addition, the Company will selectively pursue exploration projects such as the Deep Tuscaloosa in Louisiana and the Deep Wilcox in Wharton County, Texas.

Mid-Continent Region. The Company's Mid-Continent proved reserves of 625 Bcfe represented 57% of the Company's total proved reserves as of December 31, 1998 and this area produced 64 Bcfe, or 49% of the Company's 1998 production.

During 1998, the Company invested approximately $63 million to drill 165 gross (96.1 net) wells in the Mid-Continent. The Company has budgeted approximately $50 million for the Mid-Continent during 1999, representing approximately 56% of the Company's total budget for exploration and development activities during the year. The Company anticipates the Mid-Continent will contribute approximately 67 Bcfe of production during 1999, or 54% of expected total production.

Gulf Coast. The Company's Gulf Coast proved reserves, consisting of the Austin Chalk Trend in Texas and Louisiana and the Tuscaloosa Trend in Louisiana, represented 151 Bcfe, or 14% of the Company's total proved reserves as of December 31, 1998. During 1998, the Gulf Coast assets produced 52 Bcfe, or 40% of the Company's total production. The Company anticipates the Gulf Coast will contribute approximately 38 Bcfe of production during 1999, or 31% of expected total production.

During 1998, the Company invested approximately $109 million to drill 37 gross (17.8 net) wells in the Gulf Coast. For 1999, the Company has budgeted approximately $6 million for Texas Austin Chalk and Louisiana Austin Chalk drilling and $15 million for Tuscaloosa exploratory drilling activities. In the aggregate, these Gulf Coast expenditures represent approximately 23% of the Company's total budget for exploration and development activities in 1999.

Helmet Area. During fiscal 1996 and 1997, the Company began to evaluate the possibility of developing a third core area of operations to complement its activities in the Mid-Continent and Gulf Coast regions. Management believed that the North American gas market would significantly tighten and as a result, Canadian natural gas prices, which have significantly lagged U.S. natural gas prices during the past 15 years, would increase in the future compared to U.S. gas prices. During 1998, the Company entered into two transactions which established a significant presence in a major gas field in northeastern British Columbia.

The Company's Canadian proved reserves of 232 Bcfe represented 21% of the Company's total proved reserves at December 31, 1998. During 1998, production from Canada was 8 Bcfe, or 6% of the Company's total production. The Company has budgeted $15 million to drill seven net wells in 1999 and expects production of 20 Bcfe, or 16% of the Company's estimated total production for 1999.

Other Operating Areas

Permian Basin. In 1995, the Company initiated drilling activity in the Permian Basin in the Lovington area of Lea County, New Mexico. In this project, the Company is utilizing 3-D seismic technology to search for prospects that management believes have been overlooked in this portion of the Permian Basin because of inconclusive results provided by traditional 2-D seismic technology. During 1998, the Company drilled seven wells in the Lovington area, four of which were successfully completed and three were unsuccessful. The Company has budgeted approximately $0.8 million to drill one gross (0.8 net) well in this area during 1999.

Wharton County, Texas. In 1997, the Company acquired approximately 25,000 net acres in Wharton County, Texas. This exploration project is seeking gas production from the shallower Frio and Yegua sands and from the Deep Wilcox at depths of up to 19,000 feet. The Company participated with a 55% interest in a 85,000 acre 3-D seismic program with Coastal Oil & Gas Corporation, Seagull Energy Corporation and other industry partners during 1998 to delineate potential future drillsites in the prospect. During 1998, the Company drilled its first well in the prospect, which was abandoned as a dry hole.

Williston Basin. In 1996, the Company began acquiring leasehold in the Williston Basin, located in eastern Montana and western North Dakota, and as of December 31, 1998 owned approximately 0.9 million gross (0.6 million net) acres. During the Transition Period, the Company drilled and successfully completed six wells targeting the Red River formation on the northern portion of its leasehold. During 1998, the Company invested approximately $4.2 million to drill three gross (2.8 net) wells in the Williston Basin. The Company does not plan to drill any wells during 1999 in the Williston Basin unless oil prices increase significantly.

Oil and Gas Reserves

The tables below set forth information as of December 31, 1998 with respect to the Company's estimated net proved reserves, the estimated future net revenue therefrom and the present value thereof at such date. Williamson Petroleum Consultants, Inc., Ryder Scott Company Petroleum Engineers and H.J. Gruy and Associates, Inc. evaluated 63%, 12% and 1%, respectively, of the Company's combined discounted future net revenues from the Company's estimated proved reserves at December 31, 1998. The remaining properties were evaluated internally by the Company's engineers. All estimates were prepared based upon a review of production histories and other geologic, economic, ownership and engineering data developed by the Company. 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 owned by the Company.

Estimated Proved Reserves as of December 31, 1998	**Oil (MBbl)**	**Gas (MMcf)**	**Total (MMcfe)**
Proved developed	18,036	658,943	767,160
Proved undeveloped	4,557	296,848	324,188
Total proved	22,593	955,791	1,091,348

Estimated Future Net Revenue as of December 31, 1998(a)	**Proved Developed**	**Proved Undeveloped**	**Total Proved**
		($ in thousands)	
Estimated future net revenue	$ 864,109	$ 344,532	$1,208,641
Present value of future net revenue	$ 513,566	$ 147,425	$ 660,991

(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, 1998. 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 $10.48 per barrel of oil and $1.68 per Mcf of gas.

The future net revenue attributable to the Company's estimated proved undeveloped reserves of $345 million at December 31, 1998, and the $147 million present value thereof, have been calculated assuming that the Company will expend approximately $144 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.

The Company's interest used in calculating proved reserves and the estimated future net revenue therefrom was determined after giving effect to the assumed maximum participation by other parties to the Company's 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, 1998. 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 the control of the Company. The reserve data set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates, and such revisions may be material. Accordingly, reserve estimates are often different from the actual quantities of oil and gas that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the present value thereof 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 the Company's proved reserves.

See Item 1 and Note 11 of Notes to Consolidated Financial Statements included in Item 8 for a description of the Company's primary and other operating areas, production and other information regarding its oil and gas properties.

ITEM 3. ***Legal Proceedings***

The Company is subject to ordinary routine litigation incidental to its business. In addition, the following matters are pending:

Securities Litigation. On January 13, 1998, a consolidated class action complaint styled *In re Chesapeake Energy Corporation Securities Litigation* was filed in the U.S. District Court for the Western District of Oklahoma. It consolidated 12 pending purported class actions filed in August and September 1997. The action is brought on behalf of purchasers of the Company's common stock and common stock options between January 25, 1996 and June 27, 1997. The defendants are the Company and the following officers and directors: Aubrey K. McClendon, Tom L. Ward, Marcus C. Rowland, Shannon T. Self, Walter C. Wilson, Henry J. Hood, Steven C. Dixon, J. Mark Lester and Ronald A. Lefaive. The complaint alleges violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 and Rule 10b-5 thereunder.

The plaintiffs assert that the defendants made material misrepresentations and failed to disclose material facts about the success of the Company's exploration and drilling activities in the Louisiana Trend. The complaint alleges the lack of disclosure artificially inflated the price of the Company's common stock during the period beginning January 25, 1996 and ending on June 27, 1997, when the Company issued a press release announcing disappointing drilling results in the Louisiana Trend and a full-cost ceiling writedown to be reflected in its June 30, 1997 financial statements. The plaintiffs further allege that certain of the named individual defendants sold the Company's common stock during the class period when they knew or should have known adverse nonpublic information. The plaintiffs seek a determination that the suit is a proper class action and damages in an unspecified amount, together with interest and costs of litigation, including attorneys' fees. The Company and the individual defendants believe that these claims are without merit and on March 16, 1998 filed a motion to dismiss. To date, the U.S. District Court has not ruled on this motion. No estimate of loss or range of estimate of loss, if any, can be made at this time.

Bayard Drilling Technologies, Inc. ("Bayard"). 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 Sections 11 and 12 of the Securities Act of 1933 and Section 408 of the Oklahoma Securities Act by the Company and others. The action was brought purportedly on behalf of investors who purchased Bayard common stock in, or traceable to, Bayard's initial public offering in November 1997. The defendants include officers and directors of Bayard who signed the registration statement, selling shareholders (including the Company) and underwriters of the offering. Total proceeds of the offering were $254 million, of which the Company received net proceeds of $90 million.

In May 1998, two additional purported class actions filed in January and February 1998 in the District Court for Oklahoma County, Oklahoma were dismissed without prejudice pursuant to stipulation of all parties. On May 12, 1998, the plaintiffs in the dismissed cases became co-lead plaintiffs in *Yuan v. Bayard, et al.*

Plaintiffs allege that the Company, which owned 30.1% of Bayard's outstanding common stock prior to the offering, was a controlling person of Bayard. Plaintiffs also allege that the Company had established an interlocking financial relationship with Bayard and was a customer of Bayard's drilling services under allegedly below-market terms. Plaintiffs also note the fact that Messrs. McClendon, Ward and Rowland, executive officers and directors of the Company, were formerly directors of Bayard. Plaintiffs assert that the Bayard prospectus contained material omissions and misstatements relating to (i) the Company's financial "problems" and their impact on Bayard's operating results, (ii) increased costs associated with Bayard's growth strategy, (iii) undisclosed pending related-party transactions between Bayard and third parties other than the Company, (iv) Bayard's planned use of offering proceeds and (v) Bayard's capital expenditures and liquidity. The alleged defective disclosures are claimed to have resulted in a decline in Bayard's share price following the public offering.

Plaintiffs seek 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. The Company believes the claims against it in this action are without merit. On September 11, 1998, the Company and the other named defendants filed a motion to dismiss. No estimate of loss or range of estimate of loss, if any, can be made at this time. Bayard has subsequently agreed to merge into a wholly-owned, newly created, special purpose subsidiary of Nabors Industries, Inc.

UPRC Patent Suit. On October 15, 1996, Union Pacific Resources Company ("UPRC") filed suit against the Company in the U.S. District Court for the Northern District of Texas, Fort Worth Division, alleging (i) infringement and inducing infringement of UPRC's claims to a patent for an invention involving a method of maintaining a borehole in a stratigraphic zone during drilling, (ii) tortious interference with contracts between UPRC and certain of its former employees regarding the confidentiality of proprietary information of UPRC and (iii) misappropriation of such proprietary information. On May 20, 1998, two orders were entered granting the Company summary judgment on several issues. The court ruled as a matter of law that UPRC's tort claims for misappropriation of trade secrets and tortious interference with business relations are barred by the statute of limitations. Further, the court found that UPRC's claim for inducement to infringe its patent for a drillbit steering method is barred as to any wells drilled by the Company prior to August 14, 1995. The only issues remaining in the case involve the validity, potential infringement and value, if any, of UPRC's patent.

UPRC's claims against the Company in *UPRC v. Chesapeake Energy Corporation, et al.* are based on services provided to the Company by a third party vendor controlled by former UPRC employees. UPRC is seeking injunctive relief, damages of an unspecified amount, including actual, enhanced, consequential and punitive damages, interest, costs and attorneys' fees. The Company believes that it has meritorious defenses to UPRC's allegations and has petitioned the court to declare the UPRC patent invalid. Various motions for summary judgment filed by both parties are pending. While no prediction can be made as to the outcome of the matter or the amount of damages that might be awarded, if any, damage estimates have been made in reports of experts filed in the proceeding. Experts for UPRC claim that damages could be as much as $18 million, while Company experts state that the amount should not exceed $25,000, in each case based on the expert's view of a reasonable royalty for use of the patent. The case has been set for trial in June 1999 on the issue of liability.

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

The 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 (adjusted for a 2-for-1 stock split on December 31, 1996) of the common stock as reported by the New York Stock Exchange:

	Common Stock	
	High	Low
Fiscal year ended June 30, 1997:		
First Quarter	$ 34.00	$ 21.00
Second Quarter	34.13	25.69
Third Quarter	31.50	19.88
Fourth Quarter	22.38	9.25
Transition Period ended December 31, 1997:		
First Quarter	11.50	6.31
Second Quarter	13.44	6.81
Fiscal year ended December 31, 1998:		
First Quarter	7.75	5.50
Second Quarter	6.00	3.88
Third Quarter	4.06	1.13
Fourth Quarter	2.63	0.75

At March 26, 1999 there were 1,025 holders of record of common stock and approximately 28,000 beneficial owners.

Dividends

The Company paid quarterly dividends of $0.02 per common share from July 1997 to July 1998. In September 1998 the Board of Directors determined that because of low oil and natural gas prices the payment of cash dividends on the common stock should be cancelled. 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.

Two of the indentures governing the Company's outstanding senior notes contain restrictions on the Company's ability to declare and pay dividends. Under these indentures, the Company may not pay any cash dividends on its common or preferred stock if (i) a default or an event of default has occurred and is continuing at the time of or immediately after giving effect to the dividend payment, (ii) the Company would not be able to incur at least $1 of additional indebtedness under the terms of the indentures, or (iii) immediately after giving effect to the dividend payment, the aggregate of all dividends and other restricted payments declared or made after the respective issue dates of the notes exceeds the sum of specified income, proceeds from the issuance of stock and debt by the Company and other amounts from the quarter in which the respective note issuances occurred to the quarter immediately preceding the date of the dividend payment. As of December 31, 1998, the Company did not meet the debt incurrence or the restricted payment tests under these indentures.

ITEM 6. *Selected Financial Data*

The following table sets forth selected consolidated financial data of the Company for each of the four fiscal years ended June 30, 1997, the six month transition period ended December 31, 1997, the six months ended December 31, 1996 and the twelve months ended December 31, 1998 and 1997. The data is derived from the consolidated financial statements of the Company. Acquisitions made by the Company 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 the consolidated financial statements, including the notes thereto, appearing in Items 7 and 8 of this report.

	Year Ended December 31,		Six Months Ended December 31,		Year Ended June 30,			
	1998	1997	1997	1996	1997	1996	1995	1994
	($ in thousands, except per share data)							
Statement of Operations Data:								
Revenues:								
Oil and gas sales	$ 256,887	$ 198,410	$ 95,657	$ 90,167	$ 192,920	$ 110,849	$ 56,983	$ 22,404
Oil and gas marketing sales	121,059	104,394	58,241	30,019	76,172	28,428	—	—
Oil and gas service operations	—	—	—	—	—	6,314	8,836	6,439
Total revenues	377,946	302,804	153,898	120,186	269,092	145,591	65,819	28,843
Operating costs:								
Production expenses	51,202	14,737	7,560	4,268	11,445	6,340	3,379	2,141
Production taxes	8,295	4,590	2,534	1,606	3,662	1,963	877	1,506
Oil and gas marketing expenses	119,008	103,819	58,227	29,548	75,140	27,452	—	—
Oil and gas service operations	—	—	—	—	—	4,895	7,747	5,199
Impairment of oil and gas properties	826,000	346,000	110,000	—	236,000	—	—	—
Impairment of other assets	55,000	—	—	—	—	—	—	—
Oil and gas depreciation, depletion and amortization	146,644	127,429	60,408	36,243	103,264	50,899	25,410	8,141
Depreciation and amortization of other assets	8,076	4,360	2,414	1,836	3,782	3,157	1,765	1,871
General and administrative	19,918	10,910	5,847	3,739	8,802	4,828	3,578	3,135
Total operating costs	1,234,143	611,845	246,990	77,240	442,095	99,534	42,756	21,993
Income (loss) from operations	(856,197)	(309,041)	(93,092)	42,946	(173,003)	46,057	23,063	6,850
Other income (expense):								
Interest and other income	3,926	87,673	78,966	2,516	11,223	3,831	1,524	981
Interest expense	(68,249)	(29,782)	(17,448)	(6,216)	(18,550)	(13,679)	(6,627)	(2,676)
	(64,323)	57,891	61,518	(3,700)	(7,327)	(9,848)	(5,103)	(1,695)
Income (loss) before income taxes and extraordinary item	(920,520)	(251,150)	(31,574)	39,246	(180,330)	36,209	17,960	5,155
Provision (benefit) for income taxes	—	(17,898)	—	14,325	(3,573)	12,854	6,299	1,250
Income (loss) before extraordinary item	(920,520)	(233,252)	(31,574)	24,921	(176,757)	23,355	11,661	3,905
Extraordinary item:								
Loss on early extinguishment of debt, net of applicable income taxes	(13,334)	(177)	—	(6,443)	(6,620)	—	—	—
Net income (loss)	(933,854)	(233,429)	(31,574)	18,478	(183,377)	23,355	11,661	3,905
Preferred stock dividends	(12,077)	—	—	—	—	—	—	—
Net income (loss) available to common shareholders	$ (945,931)	$(233,429)	$(31,574)	$ 18,478	$(183,377)	$ 23,355	$ 11,661	$ 3,905
Earnings (loss) per common share - basic:								
Income (loss) before extraordinary item	$ (9.83)	$ (3.30)	$ (0.45)	$ 0.40	$ (2.69)	$ 0.43	$ 0.22	$ 0.08
Extraordinary item	(0.14)	—	$ —	(0.10)	(0.10)	—	—	—
Net income (loss)	$ (9.97)	$ (3.30)	$ (0.45)	$ 0.30	$ (2.79)	$ 0.43	$ 0.22	$ 0.08
Earnings (loss) per common share - assuming dilution:								
Income (loss) before extraordinary item	$ (9.83)	$ (3.30)	$ (0.45)	$ 0.38	$ (2.69)	$ 0.40	$ 0.21	$ 0.08
Extraordinary item	(0.14)	—	—	(0.10)	(0.10)	—	—	—
Net income (loss)	$ (9.97)	$ (3.30)	$ (0.45)	$ 0.28	$ (2.79)	$ 0.40	$ 0.21	$ 0.08
Cash dividends declared per common share	$ 0.04	$ 0.06	$ 0.04	$ —	$ 0.02	$ —	$ —	$ —
Cash Flow Data:								
Cash provided by operating activities before changes in working capital	$ 117,500	$ 152,196	$ 67,872	$ 76,816	$ 161,140	$ 88,431	$ 45,903	$ 15,527
Cash provided by operating activities	94,639	181,345	139,157	41,901	84,089	120,972	54,731	19,423
Cash used in investing activities	548,050	476,209	136,504	184,149	523,854	344,389	112,703	29,211
Cash provided by (used in) financing activities	363,797	277,985	(2,810)	231,349	512,144	219,520	97,282	21,162
Effect of exchange rate changes on cash	(4,726)	—	—	—	—	—	—	—
Balance Sheet Data (at end of period):								
Total assets	$ 812,615	$ 952,784	$952,784	$860,597	$949,068	$572,335	$276,693	$125,690
Long-term debt, net of current maturities	919,076	508,992	508,992	220,149	508,950	268,431	145,754	47,878
Stockholders' equity (deficit)	(248,568)	280,206	280,206	484,062	286,889	177,767	44,975	31,260

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

Overview

Although the Company's oil and gas revenues, production, and proved reserves reached record levels during the year ended December 31, 1998 (the "Current Year"), significant declines in oil and gas prices as of December 31, 1998 resulted in downward revisions in estimates of the Company's proved oil and gas reserves and the related present value of the estimated future net revenues from its proved reserves. The Company recorded an $826 million oil and gas property writedown and a net loss of $934 million during the Current Year.

In response to disappointing drilling results in Louisiana and changes occurring in oil and natural gas markets, the Company significantly revised its business strategy during the six months ended December 31, 1997 (the "Transition Period"). These revisions included (i) reducing the size and risk of its exploratory drilling program, especially in the Louisiana Trend, (ii) acquiring significant volumes of long-lived natural gas reserves, particularly in the Mid-Continent region of the U.S., and (iii) building a larger inventory of lower risk drilling opportunities through acquisitions and joint ventures. Further, the Company reduced its capital expenditure budget for exploration and development to more closely match anticipated cash flow from operations.

As part of this revised strategy, the Company acquired various proved oil and gas reserves through merger or through purchases of oil and gas properties. During the Current Year, the Company acquired approximately 750 Bcfe of proved reserves primarily in eight major transactions. Of these transactions, three were closed in the first quarter of 1998, and five were closed during the second quarter of 1998. These acquisitions increased oil and gas production volumes and revenues, decreased DD&A per Mcfe, and increased production expenses during the Current Year. Long-term debt and interest expense also increased as a result of the financing required to fund these acquisitions. The total consideration given for the acquisitions was 30.8 million shares of Company common stock, $280 million of cash, the assumption of $205 million of debt, and the incurrence of approximately $20 million of other acquisition related costs.

The Company incurred an $826 million impairment of oil and gas properties in the Current Year. The writedown was caused by a combination of several factors, including the acquisitions completed by the Company during the Current Year, which were accounted for using the purchase method, and the significant decreases in oil and gas prices throughout the Current Year. Oil and gas prices used to value the Company's 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 the remaining contributing factors which led to the writedown in the Current Year.

During the Current Year, the Company participated in 242 gross (135.2 net) wells, 156 of which were Company operated. A summary of the Company's drilling activities and capital expenditures by primary operating area is as follows ($ in thousands):

			Capital Expenditures – Oil and Gas Properties					
	Gross Wells	Net Wells	Drilling	Leasehold	Sub-Total	Acquisitions	Sale of Properties	Total
Mid-Continent	165	96.1	$ 63,431	$ 4,779	$ 68,210	$ 662,104	$(15,712)	$714,602
Gulf Coast	37	17.8	109,122	13,921	123,043	—	—	123,043
Canada	20	6.4	10,011	2,535	12,546	78,176	—	90,722
All other areas	20	14.9	41,611	5,134	46,745	—	—	46,745
Total	242	135.2	$224,175	$26,369	$250,544	$740,280	$(15,712)	$975,112

The Company's proved reserves increased 144% to an estimated 1,091 Bcfe at December 31, 1998, an increase of 643 Bcfe from the 448 Bcfe of estimated proved reserves at December 31, 1997 (see Note 11 of Notes to Consolidated Financial Statements in Item 8).

The Company's strategy for 1999 is to continue developing its natural gas assets by drilling, but at a significantly reduced pace. The Company has reduced its capital expenditure budget (before any acquisitions) to approximately $90 million and has reduced the Gulf Coast drilling component significantly. Furthermore, the Company has increased its use of 3-D seismic to assist in reducing exploratory risks and increasing economic returns from its drilling programs. The Company has conducted, participated in, or is actively pursuing more than 25 3-D seismic programs to evaluate the Company's acreage inventory.

The following table sets forth certain operating data of the Company for the periods presented:

	Year Ended December 31,		Six Months Ended December 31,		Year Ended June 30,	
	1998	1997	1997	1996	1997	1996
Net Production Data:						
Oil (MBbl)	5,976	3,511	1,857	1,116	2,770	1,413
Gas (MMcf)	94,421	59,236	27,326	30,095	62,005	51,710
Gas equivalent (MMcfe)	130,277	80,302	38,468	36,791	78,625	60,190
Oil and Gas Sales ($ in 000's):						
Oil	$ 75,877	$ 68,079	$ 34,523	$ 24,418	$ 57,974	$ 25,224
Gas	181,010	130,331	61,134	65,749	134,946	85,625
Total oil and gas sales	$256,887	$198,410	$ 95,657	$ 90,167	$ 192,920	$ 110,849
Average Sales Price:						
Oil ($ per Bbl)	$ 12.70	$ 19.39	$ 18.59	$ 21.88	$ 20.93	$ 17.85
Gas ($ per Mcf)	$ 1.92	$ 2.20	$ 2.24	$ 2.18	$ 2.18	$ 1.66
Gas equivalent ($ per Mcfe)	$ 1.97	$ 2.47	$ 2.49	$ 2.45	$ 2.45	$ 1.84
Oil and Gas Costs ($ per Mcfe):						
Production expenses and taxes	$ .45	$ .24	$ .27	$ .16	$ .19	$ .14
General and administrative	$ .15	$ .14	$ .15	$ .10	$ .11	$ .08
Depreciation, depletion and amortization	$ 1.13	$ 1.59	$ 1.57	$ .99	$ 1.31	$ .85
Net Wells Drilled:						
Horizontal wells	20	69	27	34	76	42
Vertical wells	116	32	14	13	31	27
Net Wells at End of Period	2,405	401	401	210	270	187

Results of Operations

Year Ended December 31, 1998 and 1997

General. In the Current Year, the Company realized a net loss of $933.9 million, or a loss of $9.97 per common share, on total revenues of $381.9 million. This compares to a net loss of $233.4 million, or a loss of $3.30 per common share, on total revenues of $390.5 million during the year ended December 31, 1997 (the "Prior Year"). The loss in the Current Year was caused primarily by an $826.0 million oil and gas property writedown recorded under the full-cost method of accounting and a $55.0 million writedown of other assets. See "Impairment of Oil and Gas Properties" and "Impairment of Other Assets".

Oil and Gas Sales. During the Current Year, oil and gas sales increased 29% to $256.9 million versus $198.4 million for the Prior Year. The increase in oil and gas sales resulted primarily from growth in production volumes. For the Current Year, the Company produced 130.3 Bcfe at a weighted average price of $1.97 per Mcfe, compared to 80.3 Bcfe produced in the Prior Year at a weighted average price of $2.47 per Mcfe.

The following table shows the Company's production by region for the Current Year and the Prior Year:

	For the Year Ended December 31,			
	1998		1997	
	MMcfe	Percent	MMcfe	Percent
Mid-Continent	64,038	49%	17,685	22%
Gulf Coast	52,463	40	60,662	76
Canada	7,746	6	—	—
All other areas	6,030	5	1,955	2
Total production	130,277	100%	80,302	100%

Natural gas production represented approximately 72% of the Company's total production volume on an equivalent basis in the Current Year, compared to 74% in the Prior Year. This decrease in gas production as a percentage of total production was primarily the result of new production in the Louisiana Trend, which tends to produce more oil than gas. In 1999, the Company's production is estimated to be approximately 80% gas.

For the Current Year, the Company realized an average price per barrel of oil of $12.70, compared to $19.39 in the Prior Year. Gas price realizations decreased from $2.20 per Mcf in the Prior Year to $1.92 per Mcf in the Current Year. The Company's hedging activities resulted in an increase in oil and gas revenues of $11.8 million in the Current Year and a decrease in oil and gas revenues of $4.6 million in the Prior Year.

Oil and Gas Marketing Sales. The Company realized $121.1 million in oil and gas marketing sales for third parties in the Current Year, with corresponding oil and gas marketing expenses of $119.0 million, for a net margin of $2.1 million. This compares to sales of $104.4 million, expenses of $103.8 million, and a margin of $0.6 million in the Prior Year.

Production Expenses and Taxes. Production expenses and taxes, which include lifting costs, production taxes and ad valorem taxes, increased to $59.5 million in the Current Year, compared to $19.3 million in the Prior Year. These increases were primarily the result of increased production and increased operating costs. On a unit of production basis, production expenses and taxes increased to $0.45 per Mcfe compared to $0.24 per Mcfe in the Prior Year due primarily to the higher per unit operating costs associated with many of the oil and gas properties acquired during the Current Year. The Company expects that production expenses per Mcfe will generally remain the same in 1999.

Impairment of Oil and Gas Properties. The Company utilizes the full-cost method to account for its 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 the Company's independent engineering consultants and Company 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.

The Company incurred an impairment of oil and gas properties charge of $826 million in the Current Year. The writedown was caused by a combination of several factors, including the acquisitions completed by the Company during the Current Year, which were accounted for using the purchase method, and the significant decreases in oil and gas prices throughout the Current Year. Oil and gas prices used to value the Company's 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 the remaining factors which contributed to the writedown in the Current Year.

Impairment of Other Assets. The Company incurred a $55 million impairment charge during the Current Year. Of this amount, $30 million relates to the Company's investment in preferred stock of Gothic Energy Corporation, and the remainder was related to certain of the Company's gas processing and transportation assets located in Louisiana. No such charge was recorded in the Prior Year.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization ("DD&A") of oil and gas properties for the Current Year was $146.6 million, $19.2 million higher than the Prior Year's expense of $127.4 million. 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, decreased to $1.13 in the Current Year ($1.17 in U.S. and $0.43 in Canada) compared to $1.59 in the Prior Year. The Company expects the 1999 DD&A rate to be approximately $0.75 per Mcfe.

Depreciation and Amortization of Other Assets. Depreciation and amortization ("D&A") of other assets increased to $8.1 million in the Current Year, compared to $4.4 million in the Prior Year. This increase was caused by increased investments in depreciable buildings and equipment and increased amortization of debt issuance costs as a result of the issuance of senior notes in April 1998.

General and Administrative. General and administrative ("G&A") expenses, which are net of capitalized internal payroll and non-payroll expenses (see Note 11 of Notes to Consolidated Financial Statements), were $19.9 million in the Current Year, up 83% from $10.9 million in the Prior Year. The increase in the Current Year compared to the Prior Year is due primarily to increased personnel expenses required by the Company's growth and industry wage inflation. The Company capitalized $5.3 million and $5.3 million of internal costs in the Current Year and Prior Year, respectively, directly related to the Company's oil and gas exploration and development efforts. The Company anticipates that G&A costs for 1999 will decline as a result of reduced staffing levels.

Interest and Other Income. Interest and other income for the Current Year were $3.9 million compared to $87.7 million in the Prior Year. During the Prior Year, the Company realized a gain on the sale of its Bayard common stock of $73.8 million, the most significant component of interest and other income.

Interest Expense. Interest expense increased to $68.2 million in the Current Year, compared to $29.8 million in the Prior Year. The increase was due primarily to the issuance of $500 million of senior notes in April 1998. In addition to the interest expense reported, the Company capitalized $6.5 million of interest during the Current Year, compared to $10.4 million capitalized in the Prior Year. The Company anticipates that capitalized interest for 1999 will decrease to between $2 million and $3 million.

Provision (Benefit) for Income Taxes. The Company recorded no income taxes in the Current Year compared to an income tax benefit of $17.9 million in the Prior Year, before consideration of the $3.7 million tax benefit associated with an extraordinary loss from the early extinguishment of debt.

At December 31, 1998, the Company had U.S. and Canadian net operating loss carryforwards of approximately $571 million and $1 million, respectively, for regular federal income taxes which will expire in future years beginning in 2007. Management believes that it cannot be demonstrated at this time that it is more likely than not that the deferred income tax assets, comprised primarily of the net operating loss carryforward, will be realizable in future years, and therefore a valuation allowance of $459 million has been recorded. No deferred tax benefit related to the exercise of employee stock options was allocated to additional paid-in capital in the Current Year. The Company does not expect to record any net income tax expense in 1999 based on information available at this time.

Six Months Ended December 31, 1997 and 1996

General. For the Transition Period, the Company realized a net loss of $31.6 million, or $0.45 per common share, on total revenues of $232.9 million. This compares to net income of $18.5 million, or $0.28 per common share, on total revenues of $122.7 million in the six months ended December 31, 1996 (the "Prior Period"). The loss in the Transition Period was caused by a $110.0 million asset writedown recorded under the full-cost method of accounting, partially offset by a gain of $73.8 million from the sale of Bayard stock. See "Impairment of Oil and Gas Properties".

Oil and Gas Sales. During the Transition Period, oil and gas sales increased 6% to $95.7 million versus $90.2 million for the Prior Period. The increase in oil and gas sales resulted primarily from growth in production volumes. For the Transition Period, the Company produced 38.5 Bcfe at a weighted average price of $2.49 per Mcfe, compared to 36.8 Bcfe produced in the Prior Period at a weighted average price of $2.45 per Mcfe.

The following table shows the Company's production by region for the Transition Period and the Prior Period:

	For the Six Months Ended December 31,			
	1997		1996	
	MMcfe	Percent	MMcfe	Percent
Mid-Continent	8,852	23%	8,980	24%
Gulf Coast	26,220	68	26,243	71
All other areas	3,396	9	1,568	5
Total production	38,468	100%	36,791	100%

Natural gas production represented approximately 71% of the Company's total production volume on an equivalent basis in the Transition Period, compared to 82% in the Prior Period. This decrease in gas production as a percentage of total production was primarily the result of new production in the Louisiana Trend, which tends to produce more oil than gas.

For the Transition Period, the Company realized an average price per barrel of oil of $18.59, compared to $21.88 in the Prior Period. Gas price realizations increased slightly from $2.18 per Mcf in the Prior Period to $2.24 per Mcf in the Transition Period. The Company's hedging activities resulted in decreases in oil and gas revenues of $4.3 million and $7.1 million in the Transition Period and Prior Period, respectively.

Oil and Gas Marketing Sales. The Company realized $58.2 million in oil and gas marketing sales for third parties in the Transition Period, with corresponding oil and gas marketing expenses of $58.2 million. This compares to sales of $30.0 million, expenses of $29.5 million, and a margin of $0.5 million in the Prior Period.

Production Expenses and Taxes. Production expenses and taxes, which include lifting costs, production taxes and excise taxes, increased to $10.1 million in the Transition Period, compared to $5.9 million in the Prior Period. These increases were primarily the result of increased operating costs and increased production. On a unit of production basis, production expenses and taxes increased to $0.27 per Mcfe compared to $0.16 per Mcfe in the Prior Period.

Impairment of Oil and Gas Properties. The Company incurred an impairment of oil and gas properties charge of $110.0 million for the Transition Period. This writedown was caused by several factors, including oil prices declining from $18.38 at June 30, 1997 to $17.62 at December 31, 1997, and drilling and completion costs continuing to escalate during the Transition Period. Higher costs caused the Company's capital spending to exceed budgeted amounts during the Transition Period and also increased the estimated future capital expenditures to be incurred to develop the Company's proved undeveloped reserves. The Company's results from wells completed during the Transition Period in the Louisiana Trend continued to be inconsistent and production performance from various properties in the Navasota River and Independence areas were lower than projected at June 30, 1997. As a result of the above factors, the Company recorded a downward revision to its proved reserves of 38 net Bcfe in the Austin Chalk Trend as of December 31, 1997.

Excluding the purchase of additional leasehold, the Company incurred approximately $85 million in capital expenditures in the Louisiana Trend during the Transition Period, of which approximately $67 million were incurred in the Masters Creek area. Approximately $16 million of the drilling costs were incurred on Company operated wells that had not been completed at December 31, 1997.

In the Masters Creek area, the Company completed operations on 11 wells during the Transition Period. Although 10 of the 11 wells were commercially productive, the drilling costs incurred through December 31, 1997 of approximately $58 million for the 10 wells were higher than anticipated and assigned reserves were lower than expected. The lower reserve quantities were due in part to lower oil prices at December 31, 1997. In addition, the Company transferred approximately $11 million of previously unevaluated leasehold costs from all areas of the Louisiana Trend to the amortization base of the full-cost pool during the Transition Period.

In connection with the Company's acquisition of AnSon Production Corporation ("AnSon") in December 1997, which was accounted for using the purchase method, the purchase price of approximately $43 million was allocated to the fair value of assets acquired. Based upon reserve estimates as of December 31, 1997, the portion of the purchase price which was allocated to evaluated oil and gas properties exceeded the associated discounted future net revenues from AnSon's estimated proved reserves by approximately $14 million.

Oil and Gas Depreciation, Depletion and Amortization. DD&A of oil and gas properties for the Transition Period was $60.4 million, $24.2 million higher than the Prior Period's expense of $36.2 million. The expense in the Transition Period was computed prior to the writedown from the impairment of oil and gas properties charge. The average DD&A rate per Mcfe increased to $1.57 in the Transition Period compared to $0.99 in the Prior Period.

Depreciation and Amortization of Other Assets. D&A of other assets increased to $2.4 million in the Transition Period, compared to $1.8 million in the Prior Period. This increase was caused by increased investments in depreciable buildings and equipment and increased amortization of debt issuance costs as a result of the issuance of senior notes in March 1997.

General and Administrative. G&A expenses, which are net of capitalized internal payroll and non-payroll expenses (see Note 11 of Notes to Consolidated Financial Statements), were $5.8 million in the Transition Period, up 56% from $3.7 million in the Prior Period. The increase in the Transition Period compared to the Prior Period results primarily from increased personnel expenses required by the Company's growth and industry wage inflation. The Company capitalized $2.4 million of internal costs in the Transition Period directly related to the Company's oil and gas exploration and development efforts, compared to $1.1 million in the Prior Period.

Interest and Other Income. Interest and other income for the Transition Period was $79.0 million compared to $2.5 million in the Prior Period. During the Transition Period, the Company realized a gain on the sale of its Bayard common stock of $73.8 million, the most significant component of interest and other income.

Interest Expense. Interest expense increased to $17.4 million in the Transition Period, compared to $6.2 million in the Prior Period. The increase was due primarily to the issuance of $300 million of senior notes in March 1997. In addition to the interest expense reported, the Company capitalized $5.1 million of interest during the Transition Period, compared to $7.6 million capitalized in the Prior Period.

Provision (Benefit) for Income Taxes. The Company recorded no income taxes for the Transition Period, compared to income tax expense of $14.3 million in the Prior Period, before consideration of the $3.7 million tax benefit associated with an extraordinary loss from the early extinguishment of debt.

At December 31, 1997, the Company had a net operating loss carryforward of approximately $337 million for regular federal income taxes which will expire in future years beginning in 2007. Management believed that it could not be demonstrated at that time that it was more likely than not that the deferred income tax assets, comprised primarily of the net operating loss carryforward, would be realizable in future years, and therefore a valuation allowance of $77.9 million was recorded. No deferred tax benefit related to the exercise of employee stock options was allocated to additional paid-in capital in the Transition Period.

<u>*Fiscal Years Ended June 30, 1997 and 1996*</u>

General. For the fiscal year ended June 30, 1997, the Company realized a net loss of $183.4 million, or $2.79 per common share, on total revenues of $280.3 million. This compares to net income of $23.4 million, or $0.40 per common share, on total revenues of $149.4 million in 1996. The loss in fiscal 1997 resulted from a $236 million asset writedown recorded in the fourth quarter under the full-cost method of accounting. See "Impairment of Oil and Gas Properties".

Oil and Gas Sales. During fiscal 1997, oil and gas sales increased 74% to $192.9 million versus $110.8 million for fiscal 1996. The increase in oil and gas sales resulted primarily from strong growth in production volumes and significantly higher average oil and gas prices. For fiscal 1997, the Company produced 78.6 Bcfe at a weighted average price of $2.45 per Mcfe, compared to 60.2 Bcfe produced in fiscal 1996 at a weighted average price of $1.84 per Mcfe. This represents production growth of 31% for fiscal 1997 compared to fiscal 1996.

The following table shows the Company's production by region for fiscal 1997 and fiscal 1996:

	For the Year Ended June 30,			
	1997		1996	
	MMcfe	Percent	MMcfe	Percent
Mid-Continent	17,370	22%	10,420	17%
Gulf Coast	57,377	73	47,234	78
Other areas	3,878	5	2,536	5
Total production	78,625	100%	60,190	100%

Natural gas production represented approximately 79% of the Company's total production volume on an equivalent basis in fiscal 1997. This compares to 86% in fiscal 1996 and 79% in fiscal 1995. This decrease in gas production as a percentage of total production in fiscal 1997 was the result of drilling in the Louisiana Trend, which tends to produce more oil than gas.

For fiscal 1997, the Company realized an average price per barrel of oil of $20.93, compared to $17.85 in fiscal 1996. The Company markets its oil on monthly average equivalent spot price contracts and typically receives a premium to the price posted for West Texas Intermediate crude oil.

Gas price realizations increased from fiscal 1996 to 1997 from $1.66 per Mcf to $2.18 per Mcf, or 31%, generally as the result of market conditions. The Company's gas price realizations in fiscal 1997 were also higher due to the increase in Louisiana Trend gas production, which generally receives premium prices at least equivalent to Henry Hub indexes due to the high Btu content and favorable market location of the production.

The Company's hedging activities resulted in decreases in oil and gas revenues of $7.4 million and $5.9 million in fiscal 1997 and 1996, respectively.

Oil and Gas Marketing Sales. In December 1995, the Company entered into the oil and gas marketing business by acquiring a subsidiary to provide natural gas marketing services, including commodity price structuring, contract administration and nomination services, for the Company, its partners and other oil and natural gas producers in geographical areas in which the Company is active. The Company realized $76.2 million in oil and gas marketing sales for third parties in fiscal 1997, with corresponding oil and gas marketing expenses of $75.1 million, resulting in a gross margin of $1.1 million. This compares to sales of $28.4 million, expenses of $27.5 million, and a margin of $0.9 million in fiscal 1996.

Oil and Gas Service Operations. On June 30, 1996, Peak USA Energy Services, Ltd., a limited partnership ("Peak"), was formed by Peak Oilfield Services Company (a joint venture between Cook Inlet Region, Inc. and Nabors Industries, Inc.) and Chesapeake for the purpose of purchasing the Company's oilfield service assets and providing rig moving, transportation and related site construction services to the Company and others in the industry. The Company sold its service company assets to Peak for $6.4 million, and simultaneously invested $2.5 million in exchange for a 33.3% partnership interest in Peak. This transaction resulted in recognition of a $1.8 million pre-tax gain during the fourth fiscal quarter of 1996 (reported in interest and other revenues). A deferred gain from the sale of service company assets of $0.9 million was recorded as a reduction in the Company's investment in Peak and was amortized to income over the estimated useful lives of the Peak assets. The Company's investment in Peak was accounted for using the equity method, and resulted in $0.5 million of income being included in interest and other revenues in fiscal 1997. The Company sold its partnership interest in Peak in June 1998.

Revenues from oil and gas service operations were $6.3 million in fiscal 1996. The related costs and expenses of these operations were $4.9 million for the year ended June 30, 1996. The gross profit margin was 22% in fiscal

1996. The gross profit margin derived from these operations is a function of drilling activities in the period, costs of materials and supplies and the mix of operations between lower margin trucking operations versus higher margin labor oriented service operations.

Production Expenses and Taxes. Production expenses and taxes, which include lifting costs, production taxes and excise taxes, increased to $15.1 million in fiscal 1997, compared to $8.3 million in fiscal 1996. This increase was primarily the result of increased production. On a unit production basis, production expenses and taxes increased to $0.19 per Mcfe, compared to $0.14 per Mcfe in fiscal 1996. During fiscal 1996, a high proportion of the Company's production was from the Giddings Field, much of which qualified for Texas severance tax exemptions.

Impairment of Oil and Gas Properties. Prior to January 1997, the Company had completed operations on one exploratory well in each of three separate areas outside Masters Creek in the Louisiana Trend. Between April 1997 and July 1997, the Company completed operations on 10 Company operated exploratory wells located outside Masters Creek in the Louisiana Trend that resulted in the addition of only 0.5 Bcfe of proved reserves. Cumulative well costs on these non-Masters Creek properties were approximately $43 million as of June 30, 1997. Of the 10 wells, one was completed on April 15, 1997, one on May 3, 1997 and eight after June 1, 1997. Based upon this information and similar data which had become available from outside operated properties in these non-Masters Creek areas of the Louisiana Trend, management determined that a significant portion of its leasehold in the Louisiana Trend outside of Masters Creek was impaired. During the quarters ended March 31, 1997 and June 30, 1997, the Company transferred $7.6 million and $86.3 million, respectively, of non-Masters Creek Louisiana Trend leasehold costs to the amortization base of the full-cost pool.

The weighted average oil and gas prices used to value the Company's proved reserves declined from $20.90 per Bbl and $2.41 per Mcf at June 30, 1996 to $18.38 per Bbl and $2.12 per Mcf at June 30, 1997. Drilling and equipment costs escalated rapidly in the fourth quarter of fiscal 1997 due primarily to higher day rates for drilling rigs, thus increasing the estimated future capital expenditures to be incurred to develop the Company's proved undeveloped reserves. The oil and gas price declines and the increased costs to drill and equip wells caused the Company to eliminate 35 gross proved undeveloped locations in the Knox Field which contained an estimated 45 net Bcfe of proved undeveloped reserves. Similar factors, combined with unfavorable drilling and production results, eliminated approximately 93 Bcfe of proved reserves in the Giddings and Louisiana Trend areas.

In the Independence area of the Giddings Field of Texas, a single well completed in late March 1997, which the Company had estimated to contain 15.7 Bcfe of Company reserves at March 31, 1997, was significantly and adversely affected by another operator's offset well which damaged the reservoir and reduced the Company's estimated ultimate recovery to 8.0 Bcfe of reserves.

In late June 1997, management reviewed its March 31, 1997 internal estimates of proved reserves and related present value and, after giving effect to the fourth quarter 1997 drilling and production results, oil and gas prices, higher drilling and completion costs, and additional leasehold acquisition costs and delay rentals, determined that the Company had less reserve potential than had previously been estimated. As a result, management estimated that at June 30, 1997 the Company would have capitalized costs of oil and gas properties which would exceed its full-cost ceiling by approximately $150 million to $200 million. On June 27, 1997, the Company issued a press release which included this estimate. Subsequently, based on the Company's final year-end estimates of its proved reserves and related estimated future net revenues, which took into account additional drilling and production results, management determined that as of June 30, 1997, its capitalized costs exceeded its full-cost ceiling by approximately $236 million. No such writedown was experienced by the Company in fiscal 1996.

Oil and Gas Depreciation, Depletion and Amortization. DD&A of oil and gas properties for fiscal 1997 was $103.3 million, $52.4 million higher than fiscal 1996's expense of $50.9 million. The expense in fiscal 1997 excluded the effects of the asset writedown. 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, increased to $1.31 in fiscal 1997 compared to $0.85 in fiscal 1996.

Depreciation and Amortization of Other Assets. D&A of other assets increased to $3.8 million in fiscal 1997, compared to $3.2 million in fiscal 1996. This increase in fiscal 1997 was caused by an increase in D&A as a result of increased investments in depreciable buildings and equipment and increased amortization of debt issuance costs as a result of the issuance of senior notes in May 1995, April 1996 and March 1997.

General and Administrative. G&A expenses, which are net of capitalized internal payroll and non-payroll expenses (see Note 11 of Notes to Consolidated Financial Statements), were $8.8 million in fiscal 1997, up 83% from $4.8 million in fiscal 1996. The increase in fiscal 1997 compared to fiscal 1996 is due primarily to increased personnel expenses required by the Company's growth and industry wage inflation. The Company capitalized $3.9 million of internal costs in fiscal 1997 directly related to the Company's oil and gas exploration and development efforts, compared to $1.7 million in 1996.

Interest and Other Income. Interest and other income for fiscal 1997 was $11.2 million compared to $3.8 million in fiscal 1996. During fiscal 1997, the Company realized $8.7 million in interest, $1.6 million of other investment income, $0.5 million from its investment in Peak, and $0.4 million in other income. During fiscal 1996, the Company realized $3.7 million of interest and other investment income and a $1.8 million gain related to the sale of certain service company assets, offset by a $1.7 million loss due to natural gas basis changes in April 1996 as a result of the Company's hedging activities.

Interest Expense. Interest expense increased to $18.6 million in fiscal 1997 as compared to $13.7 million in 1996. Interest expense in the fourth quarter of fiscal 1997 was $8.7 million, reflecting the issuance of $300 million of senior notes in March 1997. In addition to the interest expense reported, the Company capitalized $12.9 million of interest during fiscal 1997, compared to $6.4 million capitalized in fiscal 1996.

Provision (Benefit) for Income Taxes. The Company recorded an income tax benefit of $3.6 million for fiscal 1997, before consideration of the $3.8 million tax benefit associated with the extraordinary loss from the early extinguishment of debt, compared to income tax expense of $12.9 million in 1996. All of the income tax expense in 1996 was deferred due to tax net operating losses and carryovers resulting from the Company's drilling program.

The Company's loss before income taxes and extraordinary item of $180.3 million created a tax benefit for financial reporting purposes of $67.7 million. However, due to limitations on the recognition of deferred tax assets, the total tax benefit was reduced to $3.6 million.

At June 30, 1997, the Company had a net operating loss carryforward of approximately $300 million for regular federal income taxes which will expire in future years beginning in 2007. Management believed that it could not be demonstrated at that time that it was more likely than not that the deferred income tax assets, comprised primarily of the net operating loss carryforward, would be realizable in future years, and therefore a valuation allowance of $64.1 million was recorded in fiscal 1997. A deferred tax benefit related to the exercise of employee stock options of approximately $4.8 million was allocated directly to additional paid-in capital in 1997, compared to $7.9 million in 1996.

Liquidity and Capital Resources

For the Years Ended December 31, 1998 and 1997

Cash Flows from Operating Activities. Cash provided by operating activities (inclusive of changes in working capital) decreased to $94.6 million in the Current Year, compared to $181.3 million in the Prior Year. This decrease of $86.7 million was due primarily to reduced operating income resulting from significant decreases in average oil and gas prices between periods, as well as significant increases in G&A expenses and interest expense.

Cash Flows from Investing Activities. Cash used in investing activities increased to $548.1 million in the Current Year, compared to $476.2 million in the Prior Year. This increase was due primarily to the $279.9 million used to acquire certain oil and gas properties and companies with oil and gas reserves during the Current Year. However, the increase in cash used to acquire oil and gas properties was partially offset by reduced expenditures during the Current Year for exploratory and developmental drilling. During the Current Year and Prior Year, the Company invested $260 million and $471 million, respectively, for exploratory and developmental drilling. Also during the Current Year, the Company sold its 19.9% stake in Pan East Petroleum Corp. to Poco Petroleums, Ltd. for approximately $21.2 million. During the Prior Year the Company received net proceeds from the sale of its investment in Bayard common stock of approximately $73.8 million.

Cash Flows from Financing Activities. Cash provided by financing activities increased to $363.8 million in the Current Year, compared to $278.0 million in the Prior Year. During the Current Year, the Company 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 its commercial bank credit facilities. During the Current Year, the Company issued $500 million in senior notes and $230 million in preferred stock. During the Prior Year, the Company issued $300 million of senior notes.

For the Six Months Ended December 31, 1997 and 1996

Cash Flows from Operating Activities. Cash provided by operating activities (inclusive of changes in components of working capital) increased to $139.2 million in the Transition Period, compared to $41.9 million in the Prior Period. The primary reason for the increase was significant changes in the components of current assets and liabilities, specifically $92 million of short-term investments which were converted into cash during the Transition Period.

Cash Flows from Investing Activities. Cash used in investing activities decreased to $136.5 million in the Transition Period, compared to $184.1 million in the Prior Period. This decrease in cash used in investing activities was due primarily to the $90.4 million received from the sale of the Company's investment in Bayard common stock during the Transition Period, offset by other investments. Approximately $189.8 million was expended by the Company in the Transition Period for development and exploration of oil and gas properties, as compared to $186.8 million in the Prior Period. In the Transition Period, other property and equipment additions were $27.0 million primarily as a result of its $11.9 million investment in the Louisiana Chalk Gathering System and Masters Creek Gas Plant as well as additional investments in its Oklahoma City office complex.

Cash Flows from Financing Activities. Cash used in financing activities was $2.8 million during the Transition Period, compared to cash provided by financing activities of $231.3 million during the Prior Period. The decrease was due primarily to the proceeds received from the issuance of common stock during the Prior Period of $288.1 million, which was partially offset by the net payments on long-term borrowings of $56.8 million during the Prior Period.

For the Fiscal Years Ended June 30, 1997 and 1996

Cash Flows from Operating Activities. Cash provided by operating activities (inclusive of changes in components of working capital) decreased to $84.1 million in fiscal 1997, compared to $121.0 million in fiscal 1996. The primary reason for the decrease from fiscal 1996 to 1997 was significant changes in the components of current assets and liabilities, specifically $102.9 million of short-term investments at June 30, 1997.

Cash Flows from Investing Activities. Significantly higher cash was used in fiscal 1997 for development, exploration and acquisition of oil and gas properties compared to fiscal 1996. Approximately $524 million was expended by the Company in fiscal 1997 (net of proceeds from sale of leasehold, equipment and other), compared to $344 million in fiscal 1996. Net cash proceeds received by the Company for sales of oil and gas equipment, leasehold and other decreased to approximately $3.1 million in fiscal 1997, compared to $6.2 million in fiscal 1996. In fiscal 1997, other property and equipment additions were $34 million primarily as a result of its $16.8 million investment in the Louisiana Chalk Gathering System and Masters Creek Gas Plant as well as additional investments in its Oklahoma City office complex.

Cash Flows from Financing Activities. On December 2, 1996, the Company completed a public offering of 8,972,000 shares of common stock at a price of $33.63 per share resulting in net proceeds to the Company of approximately $288.1 million. Approximately $55.0 million of the proceeds was used to defease the Company's $47.5 million senior notes due 2001, and $11.2 million of the proceeds was used to retire all amounts outstanding under the Company's commercial bank credit facilities.

On March 17, 1997, the Company concluded the sale of $150 million of 7.875% senior notes due 2004, and $150 million of 8.5% senior notes due 2012, which offering resulted in net proceeds to the Company of approximately $292.6 million. The 7.875% senior notes were issued at 99.92% of par and the 8.5% senior notes were issued at 99.414% of par. The 7.875% senior notes and the 8.5% senior notes are redeemable at the option of the Company at any time at the redemption or make-whole prices set forth in the respective indentures.

In fiscal 1996, cash flows from financing activities were $219.5 million, largely as the result of the issuance of 5,989,500 shares of common stock (net proceeds to the Company of approximately $99.4 million) and $120 million of 9.125% senior notes due 2006.

Financial Flexibility and Liquidity

The Company had a working capital deficit of $13 million at December 31, 1998 and a cash balance of $30 million. The Company has a $50 million revolving bank credit facility, which matures in August 1999, with an initial committed borrowing base of $50 million. As of December 31, 1998, the Company had borrowed $25 million under this facility, which was included in the working capital deficit as a short-term obligation. Borrowings under the facility are secured by certain producing oil and gas properties and bear interest at a rate of 7.75% per annum as of December 31, 1998.

The senior note indentures contain various restrictions for the Company and its restricted subsidiaries to incur additional indebtedness. As of December 31, 1998, the Company estimates that secured commercial bank indebtedness of $115 million could have been incurred within these restrictions. This restriction does not apply to borrowings incurred by CEMI, an unrestricted subsidiary.

The senior note indentures also limit the Company's ability to make restricted payments (as defined), including the payment of preferred stock dividends, unless certain tests are met. As of December 31, 1998, the Company was unable to meet the requirements to incur additional unsecured indebtedness, and consequently was not able to pay cash dividends on its 7% cumulative convertible preferred stock on February 1, 1999. Subsequent payments will be subject to the same restrictions and are dependent upon variables that are beyond the Company's ability to predict. This restriction does not affect the Company's ability to borrow under or expand its secured commercial bank facility. If the Company fails to pay dividends for six quarterly periods, the holders of preferred stock would be entitled to elect two additional members to the Board.

Debt ratings for the senior notes are B3 by Moody's Investors Service and B by Standard & Poor's Corporation as of March 19, 1999, and both have placed the Company on review with negative implications. There are no scheduled principal payments required on any of the senior notes until March 2004.

The Company believes it has adequate resources, including cash on hand, budgeted cash flow from operations and proceeds from miscellaneous asset sales, to fund its capital expenditure budget for exploration and development activities during 1999, which are currently estimated to be approximately $90 million. The Company anticipates proceeds from miscellaneous asset sales will be approximately $45 million during 1999. However, continued low oil and gas prices or unfavorable drilling results could cause the Company to further reduce its drilling program, which is largely discretionary.

Year 2000

Project. The Company has placed a high priority on proactively resolving computer or embedded chip problems related to the "Year 2000" which may have adverse material effects on its continuing operations or cash flow. This problem would be caused by the inability of a component (software, hardware or equipment with embedded microprocessors) to correctly process date data in and between the 20th and 21st centuries, and therefore fail to properly perform its intended functions and/or to exchange correct date data with other components. This problem would most typically be caused by erroneous date calculations, which result from using two digits to signify a year (century implied), handling leap years incorrectly or the use of "special" values that can be confused with legitimate calendar dates. The scope of the Year 2000 project includes conducting an inventory of the Company's software, hardware and "embedded systems" equipment, assessing potential for failure and the associated risk, prioritizing the need for remedial actions, identifying an appropriate action, then implementing and testing. In addition, the Company is taking a similar approach to mitigating risks associated with the Year 2000 readiness of material business partners (vendors, suppliers, customers, etc.). The project will also identify contingency plans to cope with unexpected events resulting from Year 2000 issues.

Beginning in mid-1997, the Company began an assessment of its core financial and operational software systems. Three critical systems were identified with date sensitivities: oil and gas financial accounting, production accounting and land/lease administration. A Year 2000 compliant release of the oil and gas financial accounting package in use at the Company is available and has been scheduled for implementation during the third quarter of 1999. The production accounting system in use at the Company is also scheduled for upgrade to a Year 2000 compliant version during the first half of 1999. The timing of these upgrades have been scheduled to be concurrent with the respective vendors' support requirements and to take advantage of additional feature or performance enhancements. A project has been underway since early 1997 to implement a completely revamped version of the land/lease administration package in use at the Company to provide significantly increased functionality and reliability. The terms of this development arrangement stipulated Year 2000 compliance. Preliminary versions of the system have been installed and are being tested. As part of the testing, Year 2000 compliance will be assured. Assessment continues for lower priority software systems.

In addition, the Year 2000 compliant AS/400, on which the accounting package resides, was upgraded to provide additional capacity in late 1997. Operating system upgrades will be implemented in the near future for the Windows NT based servers to complete their remediation.

Other activities either already underway or scheduled include testing of desktop PCs, assessment of material business partners and inventory of embedded systems in field locations. The following table summarizes the current overall status of the project with anticipated completion dates:

		Phase	
Component	Inventory	Assessment/ Prioritization	Remediation/ Contingency
Software	March 1999	May 1999	September 1999
Hardware	March 1999	April 1999	June 1999
Business partners	March 1999	May 1999	June 30, 1999
Embedded systems (non-IT systems)	May 1999	June 1999	September 1999

In addition to the above, during the third quarter of 1999 the Company will develop an overall contingency plan to assure continued operations which will include precautionary measures.

Cost. To date, the Company has incurred minimal consulting costs for Year 2000 project planning and scope definition. The Company plans to acquire a Year 2000 assessment and testing suite in early 1999 for approximately $50,000 and to use contract staff to assist in the financial systems upgrade at a projected cost of $70,000. For currently identified software systems requiring a Year 2000 upgrade, the vendor is providing that upgrade under the terms of existing maintenance agreements, and thus no additional license or upgrade fees are required. In all cases these upgrades had been previously scheduled to maintain desired vendor support and no upgrade project schedule has been accelerated to achieve Year 2000 compliance, nor has any project been deferred because of Year 2000 concerns or efforts. An accurate cost cannot be determined prior to conclusion of the Assessment/Prioritization phase, but it is expected total project expenditures, including the use of outside consultants, should not exceed $1 million. This does not include any costs which may be assessed by joint venture partners on properties not operated by the Company.

Risks/Contingency. The failure to remediate critical systems (software, hardware or embedded systems), or the failure of a material business partner to resolve critical Year 2000 issues, could have a serious adverse impact on the ability of the Company to continue operations and meet obligations. At the current time, it is believed that any interruption in operation will be minor and short-lived and will pose no safety or environmental risks. However, until all assessment phases have been completed, it is impossible to accurately identify the risks, quantify potential impacts or establish a contingency plan. The Company has not yet clearly identified the most reasonably likely worst case scenario if the Company and material business partners do not achieve Year 2000 compliance on a timely basis. The Company currently intends to complete its contingency planning by September 30, 1999, with testing and training to take place early in the fourth quarter.

Recently Issued Accounting Standards

On June 15, 1998, the Financial Accounting Standards Board issued FAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("FAS 133"). FAS 133 establishes a new model for accounting for derivatives and hedging activities and supersedes and amends a number of existing standards. FAS 133 is effective for all fiscal quarters of fiscal years beginning after June 15, 1999.

FAS 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 FAS 133 are required to be reported in earnings. In addition, all hedging relationships must be designated, reassessed and documented pursuant to the provisions of FAS 133. The Company has not yet determined the impact that adoption of FAS 133 will have on the financial statements.

Forward Looking Statements

This Form 10-K 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. All statements other than statements of historical facts included in this Form 10-K, including, without limitation, statements regarding oil and gas reserve estimates, planned capital expenditures, expected oil and gas production, the Company's financial position, business strategy and other plans and objectives for future operations, expected future expenses, realization of deferred tax assets, and Year 2000 compliance efforts, are forward-looking statements. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. Factors that could cause actual results to differ materially from those expected by the Company, including, without limitation, factors discussed under Risk Factors in Item 1 of this Form 10-K, are substantial indebtedness, impairment of asset value, need to replace reserves, substantial capital requirements, ability to supplement capital resources with asset sales, fluctuations in the prices of oil and gas, uncertainties inherent in estimating quantities of oil and gas reserves, projecting future rates of production and the timing of development expenditures, competition, operating risks, restrictions imposed by lenders, liquidity and capital requirements, the effects of governmental and environmental regulation, pending patent and securities litigation, adverse changes in the market for the Company's oil and gas production and the Company's ability to successfully address Year 2000 issues. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. The Company undertakes no obligation to release publicly the result of any revisions to these forward-looking statements that may be made to reflect events or circumstances after the date hereof, including, without limitation, changes in the Company's business strategy or planned capital expenditures, or to reflect the occurrence of unanticipated events.

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

Commodity Price Risk

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

Periodically the Company utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include (i) swap arrangements that establish an index-related price above which the Company pays the counterparty and below which the Company is paid by the counterparty, (ii) the purchase of index-related puts that provide for a "floor" price below which the counterparty pays the Company the amount by which the price of the commodity is below the contracted floor, (iii) the sale of index-related calls that provide for a "ceiling" price above which the Company pays the counterparty the amount by which the price of the commodity is above the contracted ceiling, and (iv) basis protection swaps, which are arrangements that guarantee the price differential of oil or gas from a specified delivery point or points. Results from commodity hedging transactions are reflected in oil and gas sales to the extent related to the Company's oil and gas production. The Company only enters into commodity hedging transactions related to the Company's oil and gas production volumes or CEMI's physical purchase or sale commitments. 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, 1998, the Company had the following natural gas swap arrangements designed to hedge a portion of the Company's domestic gas production for periods after December 1998:

Months	Volume (MMBtu)	NYMEX-Index Strike Price (per MMBtu)
February 1999	4,300,000	$ 1.968
March 1999	4,600,000	1.968
April 1999	4,500,000	1.968
May 1999	4,600,000	1.968
June 1999	1,200,000	1.950
July 1999	1,240,000	1.950
August 1999	1,240,000	1.950
September 1999	1,200,000	1.950

During 1998, the Company closed transactions for natural gas previously hedged for the period April 1999 through November 1999 for net proceeds of $0.5 million.

Subsequent to December 31, 1998, the Company entered into additional natural gas swap arrangements for 6,100,000 MMBtu at a strike price of $1.875 for the period from June 1999 through September 1999. Such swap arrangements, along with those listed above and other miscellaneous transactions, were closed as of March 15, 1999, resulting in net proceeds of $4.7 million.

As of December 31, 1998, the Company had the following natural gas swap arrangements designed to hedge a portion of the Company's Canadian gas production for periods after December 1998:

Months	Volume (MMBtu)	Index Strike Price (per MMBtu)
January 1999	589,000	$ 1.60
February 1999	532,000	1.60
March 1999	589,000	1.60
April 1999	570,000	1.60
May 1999	589,000	1.60
June 1999	570,000	1.60
July 1999	589,000	1.60
August 1999	589,000	1.60
September 1999	570,000	1.60

If the swap arrangements listed above had been settled on December 31, 1998, the Company would have incurred a loss of $0.8 million.

As of December 31, 1998, the Company had the following oil swap arrangements for periods after December 1998:

Months	Monthly Volume (Bbls)	NYMEX Heating Oil Minus NYMEX Crude Oil Index Strike Price (per Bbl)
January 1999	217,000	$ 2.957
February 1999	196,000	2.957
March 1999	155,000	2.900

If the swap arrangements listed above had been settled on December 31, 1998, the Company would have incurred a loss of $0.2 million. Subsequent to December 31, 1998, the Company settled the swap arrangements listed above for the periods of January 1999 and February 1999 resulting in a $0.4 million loss.

In addition to commodity hedging transactions related to the Company's oil and gas production, CEMI periodically enters into various hedging transactions designed to hedge against physical purchase commitments made by CEMI. 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

The Company also utilizes hedging strategies to manage fixed-interest rate exposure. Through the use of a swap arrangement, the Company believes it can benefit from stable or falling interest rates and reduce its current interest expense. For the year ended December 31, 1998, the Company's interest rate swap resulted in a $0.7 million reduction of interest expense.

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of December 31, 1998, the carrying amounts of short-term borrowings are representative of fair values because of the short-term maturity of these instruments. The fair value of the long-term debt has been estimated based on quoted market prices.

	December 31, 1998							
	Expected Fiscal Year of Maturity							
	1999	2000	2001	2002	2003	Thereafter	Total	Fair Value
	($ in millions)							
Liabilities:								
Short-term debt – variable rate	$ 25	$ —	$ —	$ —	$ —	$ —	$ 25	$ 25
Average interest rate	7.75%	—	—	—	—	—		
Long-term debt, including current portion – fixed rate	$ —	$ —	$ —	$ —	$ —	$ 920	$ 920	$ 655
Average interest rate	—	—	—	—	—	9.1%		

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

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders
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, 1998 and 1997, and at June 30, 1997, and the results of their operations and their cash flows for the year ended December 31, 1998, for the six months ended December 31, 1997, and for the years ended June 30, 1997 and 1996, in conformity with generally accepted accounting principles. In addition, in our opinion, the financial statement schedules 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 schedules are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards 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 the opinion expressed above.

PRICEWATERHOUSECOOPERS LLP
Oklahoma City, Oklahoma
March 18, 1999

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 1998	December 31, 1997	June 30, 1997
	($ in thousands)		
CURRENT ASSETS:			
Cash and cash equivalents	$ 29,520	$ 123,860	$ 124,017
Restricted cash	5,754	—	—
Short-term investments	—	12,570	104,485
Accounts receivable:			
Oil and gas sales	13,835	10,654	10,906
Oil and gas marketing sales	19,636	20,493	19,939
Joint interest and other, net of allowances of $3,209,000, $691,000 and $387,000, respectively	27,373	38,781	25,311
Related parties	15,455	4,246	7,401
Inventory	5,325	5,493	4,854
Other	1,101	1,624	692
Total Current Assets	117,999	217,721	297,605
PROPERTY AND EQUIPMENT:			
Oil and gas properties, at cost based on full-cost accounting:			
Evaluated oil and gas properties	2,142,943	1,095,363	865,516
Unevaluated properties	52,687	125,155	128,505
Less: accumulated depreciation, depletion and amortization	(1,574,282)	(602,391)	(431,983)
	621,348	618,127	562,038
Other property and equipment	79,718	67,633	50,379
Less: accumulated depreciation and amortization	(37,075)	(6,573)	(5,051)
Total Property and Equipment	663,991	679,187	607,366
OTHER ASSETS	30,625	55,876	44,097
TOTAL ASSETS	$ 812,615	$ 952,784	$ 949,068

LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)

	December 31, 1998	December 31, 1997	June 30, 1997
CURRENT LIABILITIES:			
Notes payable and current maturities of long-term debt	$ 25,000	$ —	$ 1,380
Accounts payable	36,854	81,775	86,817
Accrued liabilities and other	46,572	42,733	28,701
Revenues and royalties due others	22,858	28,972	29,428
Total Current Liabilities	131,284	153,480	146,326
LONG-TERM DEBT, NET	919,076	508,992	508,950
REVENUES AND ROYALTIES DUE OTHERS	10,823	10,106	6,903
CONTINGENCIES AND COMMITMENTS (Note 4)			
STOCKHOLDERS' EQUITY (DEFICIT):			
Preferred Stock, $.01 par value, 10,000,000 shares authorized; 4,600,000, 0 and 0 shares of 7% cumulative convertible stock issued and outstanding at December 31, 1998 and 1997, and June 30, 1997, respectively, entitled in liquidation to $230 million	230,000	—	—
Common Stock, par value of $.01, 250,000,000 shares authorized; 105,213,750, 74,298,061 and 70,276,975 shares issued and outstanding at December 31, 1998 and 1997, and June 30, 1997, respectively	1,052	743	703
Paid-in capital	682,263	460,770	432,991
Accumulated earnings (deficit)	(1,127,195)	(181,270)	(146,805)
Accumulated other comprehensive income (loss)	(4,726)	(37)	—
Less: treasury stock, at cost; 8,503,300, 0 and 0 shares at December 31, 1998 and 1997, and June 30, 1997, respectively	(29,962)	—	—
Total Stockholders' Equity (Deficit)	(248,568)	280,206	286,889
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 812,615	$ 952,784	$ 949,068

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 1998	Six Months Ended December 31, 1997	Year Ended June 30, 1997	Year Ended June 30, 1996
	($ in thousands, except per share data)			
REVENUES:				
Oil and gas sales	$ 256,887	$ 95,657	$ 192,920	$ 110,849
Oil and gas marketing sales	121,059	58,241	76,172	28,428
Oil and gas service operations	—	—	—	6,314
Total Revenues	377,946	153,898	269,092	145,591
OPERATING COSTS:				
Production expenses	51,202	7,560	11,445	6,340
Production taxes	8,295	2,534	3,662	1,963
Oil and gas marketing expenses	119,008	58,227	75,140	27,452
Oil and gas service operations	—	—	—	4,895
Impairment of oil and gas properties	826,000	110,000	236,000	—
Impairment of other assets	55,000	—	—	—
Oil and gas depreciation, depletion and amortization	146,644	60,408	103,264	50,899
Depreciation and amortization of other assets	8,076	2,414	3,782	3,157
General and administrative	19,918	5,847	8,802	4,828
Total Operating Costs	1,234,143	246,990	442,095	99,534
INCOME (LOSS) FROM OPERATIONS	(856,197)	(93,092)	(173,003)	46,057
OTHER INCOME (EXPENSE):				
Interest and other income	3,926	78,966	11,223	3,831
Interest expense	(68,249)	(17,448)	(18,550)	(13,679)
	(64,323)	61,518	(7,327)	(9,848)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	(920,520)	(31,574)	(180,330)	36,209
PROVISION (BENEFIT) FOR INCOME TAXES	—	—	(3,573)	12,854
INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(920,520)	(31,574)	(176,757)	23,355
EXTRAORDINARY ITEM:				
Loss on early extinguishment of debt, net of applicable income tax of $0 and $3,804,000, respectively	(13,334)	—	(6,620)	—
NET INCOME (LOSS)	(933,854)	(31,574)	(183,377)	23,355
PREFERRED STOCK DIVIDENDS	(12,077)	—	—	—
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ (945,931)	$ (31,574)	$ (183,377)	$ 23,355
EARNINGS (LOSS) PER COMMON SHARE:				
EARNINGS (LOSS) PER COMMON SHARE-BASIC:				
Income (loss) before extraordinary item	$ (9.83)	$ (0.45)	$ (2.69)	$ 0.43
Extraordinary item	(0.14)	—	(0.10)	—
Net income (loss)	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.43
EARNINGS (LOSS) PER COMMON SHARE-ASSUMING DILUTION:				
Income (loss) before extraordinary item	$ (9.83)	$ (0.45)	$ (2.69)	$ 0.40
Extraordinary item	(0.14)	—	(0.10)	—
Net income (loss)	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.40
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's):				
Basic	94,911	70,835	65,767	54,564
Assuming Dilution	94,911	70,835	65,767	58,342

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 1998	Six Months Ended December 31, 1997	Year Ended June 30, 1997	Year Ended June 30, 1996
	($ in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
NET INCOME (LOSS)	$ (933,854)	$ (31,574)	$(183,377)	$ 23,355
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:				
Depreciation, depletion and amortization	152,204	62,028	105,591	52,768
Impairment of oil and gas assets	826,000	110,000	236,000	—
Impairment of other assets	55,000	—	—	
Deferred taxes	—	—	(3,573)	12,854
Amortization of loan costs	2,516	794	1,455	1,288
Amortization of bond discount	98	41	217	563
Bad debt expense	1,589	40	299	114
Gain on sale of Bayard stock	—	(73,840)	—	—
Gain on sale of fixed assets	(90)	(209)	(1,593)	(2,511)
Extraordinary loss	13,334	—	6,620	—
Equity in (earnings) losses from investments	703	592	(499)	—
Cash provided by operating activities before changes in current assets and liabilities	117,500	67,872	161,140	88,431
CHANGES IN ASSETS AND LIABILITIES:				
(Increase) decrease in short-term investments	12,027	92,127	(102,858)	622
(Increase) decrease in accounts receivable	12,191	(7,173)	(19,987)	(3,524)
(Increase) decrease in inventory	168	(1,584)	(1,467)	78
(Increase) decrease in other current assets	7,637	(1,519)	1,466	(1,525)
Increase (decrease) in accounts payable, accrued liabilities and other	(46,785)	(11,044)	48,085	25,834
Increase (decrease) in current and non-current revenues and royalties due others	(8,099)	478	(2,290)	11,056
Changes in assets and liabilities	(22,861)	71,285	(77,051)	32,541
Cash provided by operating activities	94,639	139,157	84,089	120,972
CASH FLOWS FROM INVESTING ACTIVITIES:				
Exploration and development of oil and gas properties	(260,006)	(189,755)	(468,462)	(342,045)
Acquisitions of oil and gas companies and properties, net of cash acquired	(279,924)	—	—	—
Investment in preferred stock of Gothic Energy Corporation	(39,500)	—	—	—
Proceeds from sale of oil and gas equipment, leasehold and other	16,008	2,503	3,095	6,167
Net proceeds from sale of Bayard stock	—	90,380	—	—
Repayment of note receivable	2,000	18,000	—	—
Proceeds from sale of investment in PanEast	21,245	—	—	
Other proceeds from sales	3,600	17	6,428	698
Long-term loans made to third parties	—	—	(20,000)	—
Investment in oil field service company	—	(200)	(3,048)	—
Investment in gas marketing company, net of cash acquired	—	—	—	(363)
Other investments	—	(30,434)	(8,000)	—
Other property and equipment additions	(11,473)	(27,015)	(33,867)	(8,846)
Cash used in investing activities	(548,050)	(136,504)	(523,854)	(344,389)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from issuance of common stock	—	—	288,091	99,498
Proceeds from long-term borrowings	658,750	—	342,626	166,667
Payments on long-term borrowings	(474,166)	—	(119,581)	(48,634)
Dividends paid on common stock	(5,592)	(2,810)	—	—
Dividends paid on preferred stock	(8,050)	—	—	—
Proceeds from issuance of preferred stock	222,663	—	—	—
Purchase of treasury stock	(29,962)	—	—	—
Cash received from exercise of stock options	—	322	1,387	1,989
Other financing	154	(322)	(379)	—
Cash provided by (used in) financing activities	363,797	(2,810)	512,144	219,520
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(4,726)	—	—	—
Net increase (decrease) in cash and cash equivalents	(94,340)	(157)	72,379	(3,897)
Cash and cash equivalents, beginning of period	123,860	124,017	51,638	55,535
Cash and cash equivalents, end of period	$ 29,520	$ 123,860	$ 124,017	$ 51,638

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)

	Year Ended December 31, 1998	Six Months Ended December 31, 1997	Year Ended June 30, 1997	Year Ended June 30, 1996
		($ in thousands)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION				
CASH PAYMENTS FOR:				
Interest, net of capitalized interest	$ 59,881	$ 17,367	$ 12,919	$ 10,751
Income taxes	$ —	$ 500	$ —	$ —
DETAILS OF ACQUISITION OF ANSON PRODUCTION CORPORATION:				
Fair value of assets acquired	$ —	$ 43,000	$ —	$ —
Accrued liability for estimated cash consideration	$ —	$ (15,500)	$ —	$ —
Stock issued (3,792,724 shares)	$ —	$ (27,500)	$ —	$ —
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:

The Company had a financing arrangement with a vendor to supply certain oil and gas equipment inventory, which was terminated during the Transition Period. The total amounts owed at June 30, 1997 and 1996 were $1,380,000 and $3,156,000, respectively. No cash consideration is exchanged for inventory under this financing arrangement until actual draws on the inventory are made.

In fiscal 1997 and 1996, the Company recognized income tax benefits of $4,808,000 and $7,950,000, respectively, related to the disposition of stock options by directors and employees of the Company. The tax benefits were recorded as an adjustment to deferred income taxes and paid-in capital.

Proceeds from the issuance of $500 million of 9.625% senior notes in April 1998, $300 million of senior notes ($150 million of 7.875% senior notes and $150 million of 8.5% senior notes) in March 1997, and $120 million of 9.125% senior notes in April 1996 are net of $11.7 million, $6.4 million and $3.9 million, respectively, in offering fees and expenses which were deducted from the actual cash received.

On December 22, 1997, the Company declared a dividend of $0.02 per common share, or $1,486,000, which was paid on January 15, 1998. On June 13, 1997 the Company declared a dividend of $0.02 per common share, or $1,405,000, which was paid on July 15, 1997.

The accompany 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)

	Year Ended December 31, 1998	Six Months Ended December 31, 1997	Year Ended June 30, 1997	Year Ended June 30, 1996
		($ in thousands)		
PREFERRED STOCK:				
Balance, beginning of period	$ —	$ —	$ —	$ —
Issuance of preferred stock	230,000	—	—	—
Balance, end of period	230,000	—	—	—
COMMON STOCK:				
Balance, beginning of period	743	703	3,008	58
Issuance of 8,972,000 shares of common stock	—	—	90	—
Issuance of 5,989,500 shares of common stock	—	—	—	299
Exercise of stock options and warrants	—	2	12	79
Issuance of 3,792,724 shares of common stock to AnSon Production Corporation	—	38	—	—
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	—	—	—
Change in par value and other	1	—	(2,407)	2,572
Balance, end of period	1,052	743	703	3,008
PAID-IN CAPITAL:				
Balance, beginning of period	460,733	432,991	136,782	30,295
Exercise of stock options and warrants	153	320	1,375	1,910
Issuance of common stock	236,013	27,459	301,593	105,516
Offering expenses and other	(16,686)	—	(13,974)	(6,317)
Stock options issued in Hugoton purchase	2,050	—	—	—
Tax benefit from exercise of stock options	—	—	4,808	7,950
Change in par value	—	—	2,407	(2,572)
Balance, end of period	682,263	460,770	432,991	136,782
ACCUMULATED EARNINGS (DEFICIT):				
Balance, beginning of period	(181,270)	(146,805)	37,977	14,622
Net income (loss)	(933,854)	(31,574)	(183,377)	23,355
Dividends on common stock	(4,021)	(2,891)	(1,405)	—
Dividends on preferred stock	(8,050)	—	—	—
Balance, end of period	(1,127,195)	(181,270)	(146,805)	37,977
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):				
Balance, beginning of period	(37)	—	—	—
Foreign currency translation adjustments	(4,689)	(37)	—	—
Balance, end of period	(4,726)	(37)	—	—
TREASURY STOCK:				
Balance, beginning of period	—	—	—	—
Purchases of treasury stock	(29,962)	—	—	—
Balance, end of period	(29,962)	—	—	—
TOTAL STOCKHOLDERS' EQUITY (DEFICIT)	$ (248,568)	$ 280,206	$ 286,889	$ 177,767
COMPREHENSIVE INCOME (LOSS):				
Net income (loss)	$ (933,854)	$ (31,574)	$ (183,377)	$ 23,355
Other comprehensive income (loss) – foreign currency translation adjustments	(4,689)	(37)	—	—
Comprehensive income (loss)	$ (938,543)	$ (31,611)	$ (183,377)	$ 23,355

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

The Company is a petroleum 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. The Company's properties are located in Oklahoma, Texas, Louisiana, Kansas, Montana, Colorado, North Dakota, New Mexico and British Columbia, Canada.

The Company changed its fiscal year end from June 30 to December 31 in 1997. The Company's results of operations and cash flows for the six months ended December 31, 1997 (the "Transition Period") are included in these consolidated financial statements.

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake Energy Corporation include the accounts of its direct and indirect wholly-owned subsidiaries (the "Company"). All significant intercompany accounts and transactions have been eliminated. Investments in companies and partnerships which give the Company significant influence, but not control, over the investee are accounted for using the equity method.

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, the Company considers investments in all highly liquid debt instruments with maturities of three months or less at date of purchase to be cash equivalents.

Investments in Securities

The Company invests in various equity securities and short-term debt instruments including corporate bonds and auction preferreds, commercial paper and government agency notes. The Company has classified all of its short-term investments in equity and debt instruments as trading securities, which are carried at fair value with unrealized holding gains and losses included in earnings. At December 31, 1998 and 1997, the Company had an unrealized holding loss of $0 and $2.4 million, respectively, included in interest and other income. At June 30, 1997, the Company had an unrealized holding loss of $0.6 million included in interest and other income. At June 30, 1996 the Company had no trading securities. Investments in equity securities and limited partnerships that do not have readily determinable fair values are stated at cost and are included in noncurrent other assets. In determining realized gains and losses, the cost of securities sold is based on the average cost method.

Inventory

Inventory consists primarily of tubular goods and other lease and well equipment which the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or market using the specific identification method.

Oil and Gas Properties

The Company follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. The Company capitalizes internal costs that can be directly identified with its acquisition, exploration and development activities and does 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, 1998, approximately 76% of the Company's proved reserve value (based on SEC PV10%) was evaluated by independent petroleum engineers, with the balance evaluated by the Company's engineers. In addition, the company's 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, $1.57 per equivalent Mcf in the Transition Period and $1.31 and $0.85 per equivalent Mcf in fiscal 1997 and 1996, respectively.

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. The Company reviews all of its 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.

The Company reviews the carrying value of its 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, shall 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 the Company's proved reserves, net of related income tax considerations, resulting in writedowns in the carrying value of oil and gas properties of $826 million. During the Transition Period, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues from the Company's proved reserves, net of related income tax considerations, resulting in a writedown in the carrying value of oil and gas properties of $110 million. During fiscal 1997, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues from the Company's proved reserves, net of related income tax considerations, resulting in a writedown in the carrying value of oil and gas properties of $236 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, the Transition Period and fiscal 1997 and 1996, interest of approximately $6.5 million, $5.1 million, $12.9 million and $6.4 million 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.

Service Operations

Certain subsidiaries of the Company performed contract services on wells the Company operated as well as for third parties until June 30, 1996. Oil and gas service operations revenues and costs and expenses reflected in the accompanying consolidated statement of operations for fiscal 1996 include amounts derived from certain of the contractual services provided. The Company's economic interest in its oil and gas properties was not affected by the performance of these contractual services and all intercompany profits have been eliminated.

On June 30, 1996, Peak USA Energy Services, Ltd., a limited partnership ("Peak"), was formed by Peak Oilfield Services Company (a joint venture between Cook Inlet Region, Inc. and Nabors Industries, Inc.) and the Company for the purpose of purchasing the Company's oilfield service assets and providing rig moving, transportation and related site construction services. The Company sold its service company assets to Peak for $6.4 million and simultaneously invested $2.5 million in exchange for a 33.3% partnership interest in Peak. This transaction resulted in recognition of a $1.8 million pre-tax gain during the fourth fiscal quarter of 1996 reported in interest and other. A deferred gain from the sale of service company assets of $0.9 million was amortized to income over the estimated useful lives of the Peak assets. The Company sold its partnership interest in Peak in June 1998.

Income Taxes

The Company has adopted Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes ("SFAS 109"). 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

In February 1997, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 128, Earnings Per Share ("SFAS 128"). SFAS 128 requires presentation of "basic" and "diluted" earnings per share, as defined, on the face of the statement of operations for all entities with complex capital structures. SFAS 128 is effective for financial statements issued for periods ending after December 15, 1997 and requires restatement of all prior period earnings per share amounts. The Company has adopted SFAS 128 and has restated all prior periods presented.

SFAS 128 requires a reconciliation of the numerators and denominators of the basic and diluted EPS computations. For 1998, the Transition Period and fiscal 1997, 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. Options to purchase 11.3 million, 8.3 million and 7.9 million shares of common stock at weighted average exercise prices of $1.86, $5.49 and $7.09 were outstanding during 1998, the Transition Period and fiscal 1997 but were not included in the computation of diluted EPS because the effect of these outstanding options would be antidilutive. A reconciliation for fiscal 1996 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
For the Year Ended June 30, 1996:			
Basic EPS			
Income available to common stockholders	$ 23,355	54,564	$ 0.43
Effect of Dilutive Securities			
Employee stock options	—	3,778	
Diluted EPS			
Income available to common stockholders and assumed conversions	$ 23,355	58,342	$ 0.40

Gas Imbalances — Revenue Recognition

Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. The Company follows the "sales method" of accounting for its gas revenue whereby the Company recognizes sales revenue on all gas sold to its purchasers, regardless of whether the sales are proportionate to the Company's ownership in the property. A liability is recognized only to the extent that the Company has a net imbalance in excess of the remaining gas reserves on the underlying properties. The Company's net imbalance positions at December 31, 1998 and 1997 and June 30, 1997 were not material.

Hedging

The Company periodically uses certain instruments to hedge its 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 the Company's oil and gas production, in oil and gas marketing sales to the extent related to the Company's marketing activities, and in interest expense to the extent so related.

Debt Issue Costs

Included in other assets are costs associated with the issuance of the Senior Notes. The remaining unamortized costs on these issuances of Senior Notes at December 31, 1998 totaled $19.7 million and are being amortized over the life of the Senior Notes.

Comprehensive Income

In 1998, the Company adopted SFAS No. 130, Reporting Comprehensive Income. This statement establishes rules for the reporting of comprehensive income and its components. Comprehensive income consists of net income and foreign currency translation adjustments and is presented in the Consolidated Statements of Stockholders' Equity (Deficit) and Comprehensive Income (Loss). The adoption of SFAS 130 had no impact on total stockholders' equity. Prior year financial statements have been reclassified to conform to the SFAS 130 requirements. All balance sheet accounts of foreign operations are translated into U.S. dollars at the year-end rate of exchange and statement of operations items are translated at the weighted average exchange rates for the year.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for the Transition Period and the years ended June 30, 1997 and 1996 to conform to the presentation used for the December 31, 1998 consolidated financial statements.

2. Senior Notes

On April 22, 1998, the Company issued $500 million principal amount of 9.625% Senior Notes due 2005 ("9.625% Senior Notes"). The 9.625% Senior Notes are redeemable at the option of the Company 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. The Company may also redeem at its 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, the Company issued $150 million principal amount of 7.875% Senior Notes due 2004 ("7.875% Senior Notes"). The 7.875% Senior Notes are redeemable at the option of the Company at any time prior to March 15, 2004 at the make-whole prices determined in accordance with the indenture.

Also on March 17, 1997, the Company issued $150 million principal amount of 8.5% Senior Notes due 2012 ("8.5% Senior Notes"). The 8.5% Senior Notes are redeemable at the option of the Company 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 therein.

On April 9, 1996, the Company issued $120 million principal amount of 9.125% Senior Notes due 2006 ("9.125% Senior Notes"). The 9.125% Senior Notes are redeemable at the option of the Company 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 therein. The Company may also redeem at its option at any time on or prior to April 15, 1999 up to $42 million of the 9.125% Senior Notes at 109.125% of the principal amount thereof with the proceeds of an equity offering.

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

The Company is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. The Company's 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 the Company's "Restricted Subsidiaries" (as defined in the respective indentures governing the Senior Notes) (collectively, the "Guarantor Subsidiaries"). Each of the Guarantor Subsidiaries is a direct or indirect wholly-owned subsidiary of the Company.

The senior note indentures contain certain covenants, including covenants limiting the Company 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. The Company is 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 the Company's ability to make restricted payments (as defined), including the payment of preferred stock dividends, unless certain tests are met. As of December 31, 1998, the Company was unable to meet the requirements to incur additional unsecured indebtedness, and consequently was not able to pay cash dividends on its 7% cumulative convertible preferred stock on February 1, 1999 (in the amount of $4,025,000). Subsequent payments will be subject to the same restrictions and are dependent upon variables that are beyond the Company's ability to predict. This restriction does not affect the Company's ability to borrow under or expand its secured commercial bank facility. If the Company fails to pay dividends for six quarterly periods, the holders of preferred stock would be entitled to elect two additional members to the Board.

Set forth below are condensed consolidating financial statements of the Guarantor Subsidiaries, the Company's subsidiaries which are not guarantors of the Senior Notes (the "Non-Guarantor Subsidiaries") and the Company. Separate audited financial statements of each Guarantor Subsidiary have not been provided because management has determined that they are not material to investors.

Chesapeake Energy Marketing, Inc. ("CEMI") was a Non-Guarantor Subsidiary for all periods presented, and the following were additional Non-Guarantor Subsidiaries: Chesapeake Acquisition Corporation during the Transition Period, Chesapeake Canada Corporation during fiscal 1997, and Chesapeake Gas Development Corporation during fiscal 1996. All of the Company's other subsidiaries were Guarantor Subsidiaries during these periods.

CONDENSED CONSOLIDATING BALANCE SHEET
As of December 31, 1998
($ in thousands)

ASSETS

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ (11,565)	$ 7,000	$ 39,839	$ —	$ 35,274
Short-term investments	—	—	—	—	—
Accounts receivable	54,384	29,641	270	(7,996)	76,299
Inventory	4,919	406	—	—	5,325
Other	721	15	365	—	1,101
Total Current Assets	48,459	37,062	40,474	(7,996)	117,999
PROPERTY AND EQUIPMENT:					
Oil and gas properties	2,142,943	—	—	—	2,142,943
Unevaluated leasehold	52,687	—	—	—	52,687
Other property and equipment	47,628	15,109	16,981	—	79,718
Less: accumulated depreciation, depletion and amortization	(1,601,931)	(8,036)	(1,390)	—	(1,611,357)
Net Property and Equipment	641,327	7,073	15,591	—	663,991
INVESTMENTS IN SUBSIDIARIES AND INTERCOMPANY ADVANCES	473,578	—	481,150	(954,728)	—
OTHER ASSETS	10,610	560	19,455	—	30,625
TOTAL ASSETS	$1,173,974	$ 44,695	$ 556,670	$ (962,724)	$ 812,615

LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 25,000	$ —	$ —	$ —	$ 25,000
Accounts payable and other	80,786	15,992	17,529	(8,023)	106,284
Total Current Liabilities	105,786	15,992	17,529	(8,023)	131,284
LONG-TERM DEBT	—	—	919,076	—	919,076
REVENUES AND ROYALTIES DUE OTHERS	10,823	—	—	—	10,823
DEFERRED INCOME TAXES	—	—	—	—	—
INTERCOMPANY PAYABLES	1,338,948	11,376	(1,350,351)	27	—
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	26	1	957	(17)	967
Other	(281,609)	17,326	969,459	(954,711)	(249,535)
	(281,583)	17,327	970,416	(954,728)	(248,568)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$1,173,974	$ 44,695	$ 556,670	$ (962,724)	$ 812,615

CONDENSED CONSOLIDATING BALANCE SHEET
As of December 31, 1997
($ in thousands)

ASSETS

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ (589)	$ 13,999	$ 110,450	$ —	$ 123,860
Short-term investments	—	—	12,570	—	12,570
Accounts receivable	57,476	22,882	1,524	(7,708)	74,174
Inventory	4,918	575	—	—	5,493
Other	1,613	1	10	—	1,624
Total Current Assets	63,418	37,457	124,554	(7,708)	217,721
PROPERTY AND EQUIPMENT:					
Oil and gas properties	1,056,118	39,245	—	—	1,095,363
Unevaluated leasehold	125,155	—	—	—	125,155
Other property and equipment	41,740	10,471	15,422	—	67,633
Less: accumulated depreciation, depletion and amortization	(593,359)	(14,650)	(955)	—	(608,964)
Net property and equipment	629,654	35,066	14,467	—	679,187
INVESTMENTS IN SUBSIDIARIES AND INTERCOMPANY ADVANCES	91,883	39,830	903,713	(1,035,426)	—
OTHER ASSETS	10,189	6,918	38,769	—	55,876
TOTAL ASSETS	$ 795,144	$ 119,271	$1,081,503	$ (1,043,134)	$ 952,784

LIABILITIES AND STOCKHOLDERS' EQUITY

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ —	$ —	$ —	$ —	$ —
Accounts payable and other	104,259	29,649	27,280	(7,708)	153,480
Total Current Liabilities	104,259	29,649	27,280	(7,708)	153,480
LONG-TERM DEBT	—	—	508,992	—	508,992
REVENUES AND ROYALTIES DUE OTHERS	10,106	—	—	—	10,106
DEFERRED INCOME TAXES	—	—	—	—	—
INTERCOMPANY PAYABLES	853,958	2,959	—	(856,917)	—
STOCKHOLDERS' EQUITY:					
Common Stock	10	3	733	(3)	743
Other	(173,189)	86,660	544,498	(178,506)	279,463
	(173,179)	86,663	545,231	(178,509)	280,206
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 795,144	$ 119,271	$1,081,503	$ (1,043,134)	$ 952,784

CONDENSED CONSOLIDATING BALANCE SHEET
As of June 30, 1997
($ in thousands)

ASSETS

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ (6,534)	$ 4,363	$ 126,188	$ —	$ 124,017
Short-term investments	—	4,324	100,161	—	104,485
Accounts receivable	47,379	19,943	3,022	(6,787)	63,557
Inventory	4,795	59	—	—	4,854
Other	666	26	—	—	692
Total Current Assets	46,306	28,715	229,371	(6,787)	297,605
PROPERTY AND EQUIPMENT:					
Oil and gas properties	865,485	31	—	—	865,516
Unevaluated leasehold	128,519	(14)	—	—	128,505
Other property and equipment	28,653	6,737	14,989	—	50,379
Less: accumulated depreciation, depletion and amortization	(436,276)	—	(758)	—	(437,034)
Net Property and Equipment	586,381	6,754	14,231	—	607,366
INVESTMENTS IN SUBSIDIARIES AND INTERCOMPANY ADVANCES	5,650	(4,833)	680,439	(681,256)	—
OTHER ASSETS	4,961	673	38,463	—	44,097
TOTAL ASSETS	$ 643,298	$ 31,309	$ 962,504	$ (688,043)	$ 949,068

LIABILITIES AND STOCKHOLDERS' EQUITY

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 1,380	$ —	$ —	$ —	$ 1,380
Accounts payable and other	122,241	17,527	11,965	(6,787)	144,946
Total Current Liabilities	123,621	17,527	11,965	(6,787)	146,326
LONG-TERM DEBT	—	—	508,950	—	508,950
REVENUES AND ROYALTIES DUE OTHERS	6,903	—	—	—	6,903
DEFERRED INCOME TAXES	—	—	—	—	—
INTERCOMPANY PAYABLES	589,111	1,492	—	(590,603)	—
STOCKHOLDERS' EQUITY:					
Common Stock	11	1	693	(2)	703
Other	(76,348)	12,289	440,896	(90,651)	286,186
	(76,337)	12,290	441,589	(90,653)	286,889
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 643,298	$ 31,309	$ 962,504	$ (688,043)	$ 949,068

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
For the Year Ended December 31, 1998:					
REVENUES:					
Oil and gas sales	$ 254,541	$ —	$ —	$ 2,346	$ 256,887
Oil and gas marketing sales	—	225,195	—	(104,136)	121,059
Total Revenues	254,541	225,195	—	(101,790)	377,946
OPERATING COSTS:					
Production expenses and taxes	59,497	—	—	—	59,497
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
General and administrative	18,081	1,766	71	—	19,918
Total Operating Costs	1,102,426	230,690	2,817	(101,790)	1,234,143
INCOME (LOSS) FROM OPERATIONS	(847,885)	(5,495)	(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)
	(95,565)	1,877	29,365	—	(64,323)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	(943,450)	(3,618)	26,548	—	(920,520)
INCOME TAX EXPENSE (BENEFIT)	—	—	—	—	—
NET INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(943,450)	(3,618)	26,548	—	(920,520)
EXTRAORDINARY ITEM:					
Loss on early extinguishment of debt, net of applicable income tax	(2,164)	—	(11,170)	—	(13,334)
NET INCOME (LOSS)	$ (945,614)	$ (3,618)	$ 15,378	$ —	$ (933,854)
For the Six Months Ended December 31, 1997:					
REVENUES:					
Oil and gas sales	$ 93,384	$ 1,199	$ —	$ 1,074	$ 95,657
Oil and gas marketing sales	—	101,689	—	(43,448)	58,241
Total Revenues	93,384	102,888	—	(42,374)	153,898
OPERATING COSTS:					
Production expenses and taxes	9,905	189	—	—	10,094
Oil and gas marketing expenses	—	100,601	—	(42,374)	58,227
Impairment of oil and gas properties	96,000	14,000	—	—	110,000
Oil and gas depreciation, depletion and amortization	59,758	650	—	—	60,408
Other depreciation and amortization	1,383	40	991	—	2,414
General and administrative	4,598	1,132	117	—	5,847
Total Operating Costs	171,644	116,612	1,108	(42,374)	246,990
INCOME (LOSS) FROM OPERATIONS	(78,260)	(13,724)	(1,108)	—	(93,092)
OTHER INCOME (EXPENSE):					
Interest and other income	515	192	110,751	(32,492)	78,966
Interest expense	(27,481)	(39)	(22,420)	32,492	(17,448)
	(26,966)	153	88,331	—	61,518
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	(105,226)	(13,571)	87,223	—	(31,574)
INCOME TAX EXPENSE (BENEFIT)	—	—	—	—	—
NET INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(105,226)	(13,571)	87,223	—	(31,574)
EXTRAORDINARY ITEM	—	—	—	—	—
NET INCOME (LOSS)	$ (105,226)	$ (13,571)	$ 87,223	$ —	$ (31,574)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
For the Year Ended June 30, 1997:					
REVENUES:					
Oil and gas sales	$ 191,303	$ —	$ —	$ 1,617	$ 192,920
Oil and gas marketing sales	—	145,942	—	(69,770)	76,172
Total Revenues	191,303	145,942	—	(68,153)	269,092
OPERATING COSTS:					
Production expenses and taxes	15,107	—	—	—	15,107
Oil and gas marketing expenses	—	143,293	—	(68,153)	75,140
Impairment of oil and gas properties	236,000	—	—	—	236,000
Oil and gas depreciation, depletion and amortization	103,264	—	—	—	103,264
Other depreciation and amortization	2,152	80	1,550	—	3,782
General and administrative	6,313	921	1,568	—	8,802
Total Operating Costs	362,836	144,294	3,118	(68,153)	442,095
INCOME (LOSS) FROM OPERATIONS	(171,533)	1,648	(3,118)	—	(173,003)
OTHER INCOME (EXPENSE):					
Interest and other income	778	749	49,224	(39,528)	11,223
Interest expense	(37,644)	(10)	(20,424)	39,528	(18,550)
	(36,866)	739	28,800	—	(7,327)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	(208,399)	2,387	25,682	—	(180,330)
INCOME TAX EXPENSE (BENEFIT)	(4,129)	47	509	—	(3,573)
NET INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(204,270)	2,340	25,173	—	(176,757)
EXTRAORDINARY ITEM:					
Loss on early extinguishment of debt, net of applicable income tax	(769)	—	(5,851)	—	(6,620)
NET INCOME (LOSS)	$ (205,039)	$ 2,340	$ 19,322	$ —	$ (183,377)
For the Year Ended June 30, 1996:					
REVENUES:					
Oil and gas sales	$ 103,712	$ 6,884	$ —	$ 253	$ 110,849
Gas marketing sales	—	34,973	—	(6,545)	28,428
Oil and gas service operations	6,314	—	—	—	6,314
Total Revenues	110,026	41,857	—	(6,292)	145,591
OPERATING COSTS:					
Production expenses and taxes	7,557	746	—	—	8,303
Gas marketing expenses	—	33,744	—	(6,292)	27,452
Oil and gas service operations	4,895	—	—	—	4,895
Oil and gas depreciation, depletion and amortization	48,333	2,566	—	—	50,899
Other depreciation and amortization	1,924	73	1,160	—	3,157
General and administrative	3,683	496	649	—	4,828
Total Operating Costs	66,392	37,625	1,809	(6,292)	99,534
INCOME (LOSS) FROM OPERATIONS	43,634	4,232	(1,809)	—	46,057
OTHER INCOME (EXPENSE):					
Interest and other income	1,917	238	1,676	—	3,831
Interest expense	(508)	(711)	(12,460)	—	(13,679)
	1,409	(473)	(10,784)	—	(9,848)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	45,043	3,759	(12,593)	—	36,209
INCOME TAX EXPENSE (BENEFIT)	15,990	1,335	(4,471)	—	12,854
NET INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	29,053	2,424	(8,122)	—	23,355
EXTRAORDINARY ITEM	—	—	—	—	—
NET INCOME (LOSS)	$ 29,053	$ 2,424	$ (8,122)	$ —	$ 23,355

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
For the Year Ended December 31, 1998:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 66,960	$ (13,137)	$ 40,816	$ —	$ 94,639
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties	(539,930)	—	—	—	(539,930)
Proceeds from sale of assets	16,008	—	3,600	—	19,608
Investment in preferred stock of Gothic Energy Corporation	(39,500)	—	—	—	(39,500)
Repayment of long-term loan	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	(482,698)	—	—
Effect of exchange rate changes on cash	(4,726)	—	—	—	(4,726)
	471,937	6,035	(118,901)	—	359,071
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
For the Six Months Ended December 31, 1997:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 28,598	$ (10,842)	$ 121,401	$ —	$ 139,157
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties	(189,772)	17	—	—	(189,755)
Proceeds from sale of assets	2,520	—	—	—	2,520
Investment in service operations	(200)	—	—	—	(200)
Other investments	(26,472)	—	99,380	—	72,908
Other additions	(22,864)	1,340	(453)	—	(21,977)
	(236,788)	1,357	98,927	—	(136,504)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Dividends paid on common stock	—	—	(2,810)	—	(2,810)
Exercise of stock options	—	—	322	—	322
Other financing	—	(322)	—	—	(322)
Intercompany advances, net	214,135	19,443	(233,578)	—	—
	214,135	19,121	(236,066)	—	(2,810)
Net increase (decrease) in cash and cash equivalents	5,945	9,636	(15,738)	—	(157)
Cash, beginning of period	(6,534)	4,363	126,188	—	124,017
Cash, end of period	$ (589)	$ 13,999	$ 110,450	$ —	$ 123,860

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
For the Year Ended June 30, 1997:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 165,850	$ (11,008)	$ (70,753)	$ —	$ 84,089
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties	(468,519)	57	—	—	(468,462)
Proceeds from sale of assets	9,523	—	—	—	9,523
Investment in service operations	(3,048)	—	—	—	(3,048)
Long-term loans to third parties	(2,000)	—	(18,000)	—	(20,000)
Other investments	—	—	(8,000)	—	(8,000)
Other additions	(24,318)	(1,999)	(7,550)	—	(33,867)
	(488,362)	(1,942)	(33,550)	—	(523,854)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowings	50,000	—	292,626	—	342,626
Payments on borrowings	(118,901)	—	(680)	—	(119,581)
Exercise of stock options	—	—	1,387	—	1,387
Issuance of common stock	—	—	288,091	—	288,091
Other financing	—	—	(379)	—	(379)
Intercompany advances, net	380,735	14,645	(395,380)	—	—
	311,834	14,645	185,665	—	512,144
Net increase (decrease) in cash and cash equivalents	(10,678)	1,695	81,362	—	72,379
Cash, beginning of period	4,144	2,668	44,826	—	51,638
Cash, end of period	$ (6,534)	$ 4,363	$ 126,188	$ —	$ 124,017
For the Year Ended June 30, 1996:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 126,868	$ 4,204	$ (10,100)	$ —	$ 120,972
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties	(341,246)	(6,099)	—	5,300	(342,045)
Proceeds from sales	12,165	—	—	(5,300)	6,865
Investment in gas marketing company	—	266	(629)	—	(363)
Other additions	(4,683)	(109)	(4,054)	—	(8,846)
	(333,764)	(5,942)	(4,683)	—	(344,389)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowings	40,350	10,300	116,017	—	166,667
Payments on borrowings	(45,397)	(3,200)	(37)	—	(48,634)
Exercise of stock options	—	—	1,989	—	1,989
Issuance of common stock	—	—	99,498	—	99,498
Intercompany advances, net	162,777	(2,616)	(160,161)	—	—
	157,730	4,484	57,306	—	219,520
Net increase (decrease) in cash and cash equivalents	(49,166)	2,746	42,523	—	(3,897)
Cash, beginning of period	53,227	5	2,303	—	55,535
Cash, end of period	$ 4,061	$ 2,751	$ 44,826	$ —	$ 51,638

3. Notes Payable and Long-Term Debt

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

	December 31, 1998	December 31, 1997	June 30, 1997
	($ in thousands)		
7.875% Senior Notes (see Note 2)	$ 150,000	$ 150,000	$ 150,000
Discount on 7.875% Senior Notes	(90)	(106)	(115)
8.5% Senior Notes (see Note 2)	150,000	150,000	150,000
Discount on 8.5% Senior Notes	(774)	(833)	(862)
9.125% Senior Notes (see Note 2)	120,000	120,000	120,000
Discount on 9.125% Senior Notes	(60)	(69)	(73)
9.625% Senior Notes (see Note 2)	500,000	—	—
10.5% Senior Notes (see Note 2)	—	90,000	90,000
Note payable to a vendor, collateralized by oil and gas tubulars, payments due 60 days from shipment of the tubulars	—	—	1,380
Other collateralized	25,000	—	—
Total notes payable and long-term debt	944,076	508,992	510,330
Less — current maturities	(25,000)	—	(1,380)
Notes payable and long-term debt, net of current maturities	$ 919,076	$ 508,992	$ 508,950

The aggregate scheduled maturities of notes payable and long-term debt for the next five fiscal years ending December 31, 2003 and thereafter were as follows as of December 31, 1998 (in thousands of dollars):

1999	$ 25,000
2000	—
2001	—
2002	—
2003	—
After 2003	919,076
	$ 944,076

4. Contingencies and Commitments

The Company and certain of its officers and directors are defendants in a consolidated class action suit alleging violations of the Securities Exchange Act of 1934. The plaintiffs assert that the defendants made material misrepresentations and failed to disclose material facts about the success of the Company's exploration efforts in the Louisiana Trend. As a result, the complaint alleges, the price of the Company's common stock was artificially inflated from January 25, 1996 until June 27, 1997, when the Company issued a press release announcing disappointing drilling results in the Louisiana Trend and a full-cost ceiling writedown to be reflected in its June 30, 1997 financial statements. The plaintiffs further allege that certain of the named individual defendants sold common stock during the class period when they knew or should have known adverse nonpublic information. The plaintiffs seek a determination that the suit is a proper class action and damages in an unspecified amount, together with interest and costs of litigation, including attorneys' fees. The Company and the individual defendants believe that these claims are without merit and have filed a motion to dismiss. No estimate of loss or range of estimate of loss, if any, can be made at this time.

Another purported class action alleging violations of the Securities Act of 1933 and the Oklahoma Securities Act is pending against the Company and others on behalf of investors who purchased common stock of Bayard Drilling Technologies, Inc. ("Bayard") in its initial public offering in November 1997. Total proceeds of the offering were $254 million, of which the Company received net proceeds of $90.2 million as a selling shareholder. Plaintiffs allege that the Company, which owned 30.1% of Bayard's common stock outstanding prior to the offering, was a controlling person of Bayard. Plaintiffs also allege that the Company had established an interlocking financial relationship with Bayard and was a customer of Bayard's drilling services under allegedly below-market terms. Plaintiffs also note the fact that three executive officers and directors of the Company were formerly directors of Bayard. Plaintiffs assert that the Bayard prospectus contained material omissions and misstatements relating to (i) the Company's financial "problems" and their impact on Bayard's operating results, (ii) increased costs associated with Bayard's growth strategy, (iii) undisclosed pending related-party transactions between Bayard and third parties other than the Company, (iv) Bayard's planned use of offering proceeds and (v) Bayard's capital expenditures and liquidity. The alleged defective disclosures are claimed to have resulted in a decline in Bayard's share price following the public offering. The plaintiffs seek 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. The Company believes that these actions are without merit and has filed a motion to dismiss. No estimate of loss or range of estimate of loss, if any, can be made at this time.

In October 1996, Union Pacific Resources Company ("UPRC") sued the Company alleging infringement of a patent for a drilling method, tortious interference with confidentiality contracts between UPRC and certain of its former employees and misappropriation of proprietary information of UPRC. UPRC's claims against the Company are based on services provided to the Company by a third party vendor controlled by former UPRC employees. UPRC is seeking injunctive relief, damages of an unspecified amount, including actual, enhanced, consequential and punitive damages, interest, costs and attorneys' fees. In May 1998, the court ruled as a matter of law that UPRC's tort claims for misappropriation of trade secrets and tortious interference with business relations are barred by the statute of limitatiions. Further, the court found that UPRC's claim for inducement to infringe its patent for a drillbit steering method is barred as to any wells drilled by the Company prior to August 14, 1995. The only issues remaining in the case involve the validity, potential infringement and value, if any, of UPRC's patent. The Company believes that it has meritorious defenses to UPRC's allegations and has petitioned the court to declare the UPRC patent invalid. Various motions for summary judgment are pending. No estimate of a probable loss or range of estimate of a probable loss, if any, can be made at this time; however, in reports filed in the proceeding, experts for UPRC claim that damages could be as much as $18 million while Company experts state that the amount should not exceed $25,000, in each case based on a reasonable royalty. This case has been set for trial in June 1999 on the issue of liability.

The Company 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 the Company.

The Company has employment contracts with its two principal shareholders and its 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 the respective terms of the agreements in the event of termination of employment without cause. These agreements expire at various times from June 30, 2000 through June 30, 2003.

Due to the nature of the oil and gas business, the Company and its subsidiaries are exposed to possible environmental risks. The Company has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. The Company 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:

	Year Ended December 31, 1998	Six Months Ended December 31, 1997	Year Ended June 30, 1997	Year Ended June 30, 1996
		($ in thousands)		
Current	$ —	$ —	$ —	$ —
Deferred	—	—	(3,573)	12,854
Total	$ —	$ —	$ (3,573)	$ 12,854

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:

	Year Ended December 31, 1998	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996
		($ in thousands)		
Computed "expected" income tax provision (benefit)	$ (322,182)	$ (11,051)	$ (63,116)	$ 12,673
Tax percentage depletion	(430)	(48)	(294)	(238)
Valuation allowance	380,969	13,818	64,116	—
State income taxes and other	(58,357)	(2,719)	(4,279)	419
	$ —	$ —	$ (3,573)	$ 12,854

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:

	Year Ended December 31, 1998	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996
		($ in thousands)		
Deferred tax liabilities:				
Acquisition, exploration and development costs and related depreciation, depletion and amortization	$ —	$ (49,657)	$ (49,831)	$ (63,725)
Deferred tax assets:				
Acquisition, exploration and development costs and related depreciation, depletion and amortization	242,765	—	—	—
Net operating loss carryforwards	214,602	126,485	112,889	50,776
Percentage depletion carryforward	1,536	1,106	1,058	764
	458,903	127,591	113,947	51,540
Net deferred tax asset (liability)	458,903	77,934	64,116	(12,185)
Less: Valuation allowance	(458,903)	(77,934)	(64,116)	—
Total deferred tax asset (liability)	$ —	$ —	$ —	$ (12,185)

SFAS 109 requires that the Company record a valuation allowance when it is more likely than not that some portion or all of the deferred tax assets will not be realized. In 1998, the Transition Period and fiscal 1997, the Company recorded an $826 million writedown, a $110 million writedown and a $236 million writedown, respectively, related to the impairment of oil and gas properties. The writedowns and significant tax net operating loss carryforwards (caused primarily by expensing intangible drilling costs for tax purposes) resulted in a net deferred tax asset at December 31, 1998 and 1997 and June 30, 1997. Management believes it is more likely than not that the Company will generate future tax net operating losses for at least the next five years.. Therefore, the Company has recorded a valuation allowance equal to the net deferred tax asset.

At December 31, 1998, the Company had U.S. and Canadian regular tax net operating loss carryforwards of approximately $571 million and $1 million, respectively, and U.S. alternative minimum tax net operating loss carryforwards of approximately $196 million. The U.S. loss carryforward amounts will expire during the years 2007 through 2018. The Company also had a percentage depletion carryforward of approximately $4 million at December 31, 1998, which is available to offset future federal income taxes payable and has no expiration date.

In accordance with certain provisions of the Tax Reform Act of 1986, a change of greater than 50% of the beneficial ownership of the Company within a three-year period (an "Ownership Change") would place an annual limitation on the Company's ability to utilize its existing tax carryforwards. Under regulations issued by the Internal Revenue Service, the Company has had two Ownership Changes. However, management believes this will not result in a significant limitation of the tax carryforwards. Acquired tax carryforwards are subject to separate limitations; however, management believes these will not result in a significant limitation of the acquired tax carryforwards.

6. Related Party Transactions

Certain directors, shareholders and employees of the Company have acquired working interests in certain of the Company's oil and gas properties. The owners of such working interests are required to pay their proportionate share of all costs. As of December 31, 1998 and 1997 and June 30, 1997, the Company had accounts receivable from related parties, primarily related to such participation, of $5.6 million, $4.2 million and $7.4 million, respectively.

Certain officers of the Company have loans due on December 31, 1999 to CEMI in the principal amount of $9.9 million. Such loans, which were first made in July 1998, are collateralized and carry an annual interest rate of 9.125%.

During 1998, the six months ended December 31, 1997 and fiscal 1997 and 1996, the Company incurred legal expenses of $493,000, $388,000, $207,000 and $347,000, respectively, for legal services provided by a law firm of which a director is a member.

7. Employee Benefit Plans

The Company maintains 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 are matched by the Company for up to 10% of the employee's annual salary with the Company's common stock. The amount of employee contribution is limited as specified in the plan. The Company may, at its discretion, make additional contributions to the plan. The Company contributed $1,359,000, $418,000, $603,000 and $187,000 to the plan during 1998, the six months ended December 31, 1997 and the fiscal years ended June 30, 1997 and 1996, 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 ($ in thousands)	Percent of Oil and Gas Sales
1998	Koch Oil Company	$ 30,564	12%
	Aquila Southwest Pipeline Corporation	28,946	11
Six Months Ended December 31,			
1997	Aquila Southwest Pipeline Corporation	$ 20,138	21%
	Koch Oil Company	18,594	19
	GPM Gas Corporation	12,610	13
Fiscal Year Ended June 30,			
1997	Aquila Southwest Pipeline Corporation	$ 53,885	28%
	Koch Oil Company	29,580	15
	GPM Gas Corporation	27,682	14
1996	Aquila Southwest Pipeline Corporation	$ 41,900	38%
	GPM Gas Corporation	28,700	26
	Wickford Energy Marketing, L.C.	18,500	17

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

The Company believes all of its material operations are part of the oil and gas industry, and therefore reports as a single industry setment. Beginning in 1998, the Company conducted foreign operations in Canada. The geographic distribution of the Company's revenue, operating income and identifiable assets are summarized below ($ in thousands):

	United States	Canada	Consolidated
1998:			
Revenue	$ 369,968	$ 7,978	$ 377,946
Operating income (loss)	(842,798)	(13,399)	(856,197)
Identifiable assets	724,713	87,902	812,615

9. Stockholders' Equity And Stock Based Compensation

During 1998, the Company's Board of Directors approved the expenditure of up to $30 million to purchase outstanding Company common stock. As of August 25, 1998, the Company had purchased approximately 8.5 million shares of common stock for an aggregate amount of $30 million pursuant to such authorization.

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

On April 22, 1998, the Company issued $230 million (4.6 million shares) of its 7% Cumulative Convertible Preferred Stock, $50 per share liquidation preference, resulting in net proceeds to the Company of $223 million.

On March 10, 1998, the Company acquired Hugoton Energy Corporation ("Hugoton") pursuant to a merger by issuing approximately 25.8 million shares of the Company's common stock in exchange for 100% of Hugoton's common stock.

On December 16, 1997, the Company acquired AnSon Production Corporation. Consideration for this merger was approximately $43 million consisting of the issuance of approximately 3.8 million shares of Company common stock and cash consideration in accordance with the terms of the merger agreement.

On December 2, 1996, the Company completed a public offering of approximately 9.0 million shares of common stock at a price of $33.63 per share, resulting in net proceeds to the Company of approximately $288.1 million.

On April 12, 1996, the Company completed a public offering of approximately 6.0 million shares of common stock at a price of $17.67 per share, resulting in net proceeds to the Company of approximately $99.4 million.

A 2-for-1 stock split of the common stock in December 1996, and a 3-for-2 stock split of the common stock in December 1995 and in June 1996 have been given retroactive effect in these financial statements.

Stock Option Plans

Under the Company's 1992 Incentive Stock Option Plan (the "ISO Plan"), options to purchase common stock may be granted only to employees of the Company and its subsidiaries. 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 10 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. No options could be granted under the ISO Plan after December 16, 1994.

Under the Company's 1992 Nonstatutory Stock Option Plan (the "NSO Plan"), non-qualified options to purchase common stock may be granted only to directors and consultants of the Company. Subject to any adjustment as provided by the NSO 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 10 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. No options can be granted under the NSO Plan after December 10, 2002.

Under the Company's 1994 Stock Option Plan (the "1994 Plan"), and its 1996 Stock Option Plan (the "1996 Plan"), incentive and nonqualified stock options to purchase Common Stock may be granted to employees and consultants of the Company and its subsidiaries. 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 10 years from the date of grant and the exercise price may not be less than 75% 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 December 16, 2004 or under the 1996 Plan after October 14, 2006.

The Company 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. No compensation expense has been recognized because the exercise price of the stock options 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 the Company had accounted for its 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, the six months ended December 31, 1997 and fiscal 1997 and 1996, respectively: interest rates (zero-coupon U.S. government issues with a remaining life equal to the expected term of the options) of 5.20%, 6.45%, 6.74% and 6.21%; dividend yields of 0.0%, 0.9%, 0.9% and 0.9%; volatility factors of the expected market price of the Company's common stock of .96, .67, .60 and .60; and weighted-average expected life of the options of four 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 the Company's 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.

The Company's pro forma information follows:

	Year Ended December 31, 1998	Six Months Ended December 31, 1997	Year Ended June 30, 1997	Year Ended June 30, 1996
	(In thousands, except per share amounts)			
Net Income (Loss)				
As reported	$ (933,854)	$ (31,574)	$ (183,377)	$ 23,355
Pro forma	(948,014)	(35,084)	(190,160)	22,081
Earnings (Loss) per Share				
As reported	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.40
Pro forma	(10.12)	(0.50)	(2.89)	0.38

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 the Company's 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 the Company's stock option activity and related information follows:

	Year Ended December 31, 1998		Six Months Ended December 31, 1997	
	Options	Weighted-Avg Exercise Price	Options	Weighted-Avg Exercise Price
Outstanding Beginning of Period	8,330,381	$ 5.49	7,903,659	$ 7.09
Granted	14,580,063	$ 2.78	3,362,207	8.29
Exercised	(108,761)	$ 1.35	(219,349)	3.13
Cancelled/Forfeited	(11,541,308)	$ 5.64	(2,716,136)	13.87
Outstanding End of Period	11,260,375	$ 1.86	8,330,381	5.49
Exercisable End of Period	3,535,126		3,838,869	
Shares Authorized for Future Grants	1,761,359		4,585,973	
Fair Value of Options Granted During the Period		$ 2.34		$ 4.98

	Year Ended June 30,			
	1997		1996	
	Options	Weighted-Avg Exercise Price	Options	Weighted-Avg Exercise Price
Outstanding Beginning of Year	7,602,884	$ 4.66	6,828,592	$ 1.97
Granted	3,564,884	19.35	2,426,850	9.98
Exercised	(1,197,998)	1.95	(1,574,046)	1.31
Cancelled/Forfeited	(2,066,111)	22.26	(78,512)	2.61
Outstanding End of Year	7,903,659	7.09	7,602,884	4.66
Exercisable End of Year	3,323,824		2,974,386	
Shares Authorized for Future Grants	5,212,056		713,826	
Fair Value of Options Granted During the Year		$ 7.51		$ 4.84

The following table summarizes information about stock options outstanding at December 31, 1998:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding @ 12/31/98	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Number Exercisable @ 12/31/98	Weighted-Avg. Exercise Price
\$0.0800 - \$0.8556	1,243,185	3.85	\$ 0.6434	1,243,185	\$ 0.6434
\$1.1300 - \$1.1300	6,708,697	9.79	\$ 1.1300	36,563	\$ 1.1300
\$1.2400 - \$2.2511	2,047,254	5.45	\$ 1.7603	1,349,704	\$ 2.0293
\$2.4311 - \$7.3100	1,062,864	7.50	\$ 4.5489	752,239	\$ 4.4790
\$8.7500 - \$8.7500	48,625	8.50	\$ 8.7500	26,310	\$ 8.7500
\$10.6900 - \$10.6900	18,750	8.75	\$10.6900	18,750	\$10.6900
\$14.2500 - \$14.2500	28,500	8.32	\$14.2500	7,125	\$14.2500
\$17.6667 - \$17.6667	1,500	7.26	\$17.6667	750	\$17.6667
\$25.8750 - \$25.8750	1,000	7.95	\$25.8750	500	\$25.8750
\$30.6250 - \$30.6250	100,000	7.77	\$30.6250	100,000	\$30.6250
\$0.0800 - \$30.6250	11,260,375	8.10	\$ 1.8620	3,535,126	\$ 2.9900

The exercise of certain stock options results in state and federal income tax benefits to the Company related to the difference between the market price of the common stock at the date of disposition (or sale) and the option price. During 1998, the six months ended December 31, 1997 and fiscal 1997 and 1996, \$0, \$0, \$4,808,000 and \$7,950,000, respectively, were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such tax benefits.

10. Financial Instruments and Hedging Activities

The Company 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. The Company's primary objective is to hedge a portion of its exposure to price volatility from producing crude oil and natural gas. These arrangements may expose the Company to credit risk from its counterparties and to basis risk. The Company does not expect that the counterparties will fail to meet their obligations given their high credit ratings.

Hedging Activities

Periodically the Company utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include (i) swap arrangements that establish an index-related price above which the Company pays the counterparty and below which the Company is paid by the counterparty, (ii) the purchase of index-related puts that provide for a "floor" price below which the counterparty pays the Company the amount by which the price of the commodity is below the contracted floor, (iii) the sale of index-related calls that provide for a "ceiling" price above which the Company pays the counterparty the amount by which the price of the commodity is above the contracted ceiling, and (iv) basis protection swaps, which are arrangements that guarantee the price differential of oil or gas from a specified delivery point or points. Results from commodity hedging transactions are reflected in oil and gas sales to the extent related to the Company's oil and gas production. The Company only enters into commodity hedging transactions related to the Company's oil and gas production volumes or CEMI's physical purchase or sale commitments. 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, 1998, the Company had the following natural gas swap arrangements designed to hedge a portion of the Company's domestic gas production for periods after December 1998:

Months	Volume (MMBtu)	NYMEX-Index Strike Price (per MMBtu)
February 1999	4,300,000	$ 1.968
March 1999	4,600,000	1.968
April 1999	4,500,000	1.968
May 1999	4,600,000	1.968
June 1999	1,200,000	1.950
July 1999	1,240,000	1.950
August 1999	1,240,000	1.950
September 1999	1,200,000	1.950

During 1998, the Company has closed transactions for natural gas previously hedged for the period April 1999 through November 1999 for net proceeds of $0.5 million.

Subsequent to December 31, 1998, the Company entered into additional natural gas swap arrangements for 6,100,000 MMBtu at a strike price of $1.875 for the period from June 1999 through September 1999. Such swap arrangements, along with those listed above and other miscellaneous transactions, were closed as of March 15, 1999, resulting in net proceeds of $4.7 million (unrealized gain of $0.8 million at December 31, 1998).

As of December 31, 1998, the Company had the following natural gas swap arrangements designed to hedge a portion of the Company's Canadian gas production for periods after December 1998:

Months	Volume (MMBtu)	Index Strike Price (per MMBtu)
January 1999	589,000	$ 1.60
February 1999	532,000	1.60
March 1999	589,000	1.60
April 1999	570,000	1.60
May 1999	589,000	1.60
June 1999	570,000	1.60
July 1999	589,000	1.60
August 1999	589,000	1.60
September 1999	570,000	1.60

If the swap arrangements listed above had been settled on December 31, 1998, the Company would have incurred a loss of $0.8 million.

As of December 31, 1998, the Company had the following oil swap arrangements for periods after December 1998:

Months	Monthly Volume (Bbls)	NYMEX Heating Oil Minus NYMEX Crude Oil Index Strike Price (per Bbl)
January 1999	217,000	$ 2.957
February 1999	196,000	2.957
March 1999	155,000	2.900

If the swap arrangements listed above had been settled on December 31, 1998, the Company would have incurred a loss of $0.2 million. Subsequent to December 31, 1998, the Company settled the swap arrangements listed above for the period of January 1999 and February 1999 resulting in a $0.4 million loss.

In addition to commodity hedging transactions related to the Company's oil and gas production, CEMI periodically enters into various hedging transactions designed to hedge against physical purchase or sale commitments made by CEMI. 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.

The Company also utilizes hedging strategies to manage fixed-interest rate exposure. Through the use of a swap arrangement, the Company believes it can benefit from stable or falling interest rates and reduce its current interest expense. For the year ended December 31, 1998, the Company's interest rate swap resulted in a $0.7 million reduction of interest expense during 1998.

Concentration of Credit Risk

Other financial instruments which potentially subject the Company to concentrations of credit risk consist principally of cash, short-term investments in debt instruments and trade receivables. The Company's accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties operated by the Company. The industry concentration has the potential to impact the Company'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. The Company generally requires 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 investments in debt securities are 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". The estimated fair value amounts have been determined by the Company 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. The Company estimates the fair value of its long-term, fixed-rate debt using quoted market prices. The Company's carrying amount for such debt at December 31, 1998 and 1997 and June 30, 1997 was $919.1 million, $509.0 million and $508.9 million, respectively, compared to approximate fair values of $654.7 million, $517.0 million and $514.1 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. The Company estimates the fair value of its convertible preferred stock, which was issued in April 1998, using quoted market prices. The Company's carrying amount for such preferred stock at December 31, 1998 was $230 million, compared to an approximate fair value of $48.9 million.

11. Disclosures About Oil And Gas Producing Activities

Net Capitalized Costs

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

December 31, 1998

	U.S.	Canada ($ in thousands)	Combined
Oil and gas properties:			
Proved	$ 2,060,076	$ 82,867	$ 2,142,943
Unproved	44,780	7,907	52,687
Total	2,104,856	90,774	2,195,630
Less accumulated depreciation, depletion and amortization	(1,556,284)	(17,998)	(1,574,282)
Net capitalized costs	$ 548,572	$ 72,776	$ 621,348

December 31, 1997

	U.S.	Canada ($ in thousands)	Combined
Oil and gas properties:			
Proved	$ 1,095,363	$ —	$ 1,095,363
Unproved	125,155	—	125,155
Total	1,220,518	—	1,220,518
Less accumulated depreciation, depletion and amortization	(602,391)	—	(602,391)
Net capitalized costs	$ 618,127	$ —	$ 618,127

June 30, 1997

	U.S.	Canada ($ in thousands)	Combined
Oil and gas properties:			
Proved	$ 865,516	$ —	$ 865,516
Unproved	128,505	—	128,505
Total	994,021	—	994,021
Less accumulated depreciation, depletion and amortization	(431,983)	—	(431,983)
Net capitalized costs	$ 562,038	$ —	$ 562,038

Unproved properties not subject to amortization at December 31, 1998 and 1997, and June 30, 1997 consisted mainly of lease acquisition costs. The Company capitalized approximately $6.5 million, $5.1 million and $12.9 million of interest during 1998, the six months ended December 31, 1997 and the year ended June 30, 1997 on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. The Company will continue to evaluate its 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 costs	$ 145,953	$ 4,584	$ 150,537
Exploration costs	63,245	5,427	68,672
Acquisition costs:			
Unproved properties	23,834	2,535	26,369
Proved properties	662,104	78,176	740,280
Sales of oil and gas properties	(15,712)	—	(15,712)
Capitalized internal costs	5,262	—	5,262
Proceeds from sale of leasehold, equipment and other	(296)	—	(296)
Total	$ 884,390	$ 90,722	$ 975,112

Six Months Ended December 31, 1997

	U.S.	Canada	Combined
		($ in thousands)	
Development costs	$ 120,628	$ —	$ 120,628
Exploration costs	40,534	—	40,534
Acquisition costs:			
Unproved properties	25,516	—	25,516
Proved properties	39,245	—	39,245
Sales of oil and gas properties	—	—	—
Capitalized internal costs	2,435	—	2,435
Proceeds from sale of leasehold, equipment and other	(1,861)	—	(1,861)
Total	$ 226,497	$ —	$ 226,497

Year Ended June 30, 1997

	U.S.	Canada	Combined
		($ in thousands)	
Development costs	$ 187,736	$ —	$ 187,736
Exploration costs	136,473	—	136,473
Acquisition costs:			
Unproved properties	140,348	—	140,348
Proved properties	—	—	—
Sales of oil and gas properties	—	—	—
Capitalized internal costs	3,905	—	3,905
Proceeds from sale of leasehold, equipment and other	(3,095)	—	(3,095)
Total	$ 465,367	$ —	$ 465,367

Year Ended June 30, 1996

	U.S.	Canada	Combined
		($ in thousands)	
Development costs	$ 138,188	$ —	$ 138,188
Exploration costs	39,410	—	39,410
Acquisition costs:			
Unproved properties	138,188	—	138,188
Proved properties	24,560	—	24,560
Sales of oil and gas properties	—	—	—
Capitalized internal costs	1,699	—	1,699
Proceeds from sale of leasehold, equipment and other	(6,167)	—	(6,167)
Total	$ 335,878	$ —	$ 335,878

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

The Company's results of operations from oil and gas producing activities are presented below for 1998, the six months ended December 31, 1997 and for the years ended June 30, 1997 and 1996, respectively. The following table includes revenues and expenses associated directly with the Company's oil and gas producing activities. It does not include any allocation of the Company's interest costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of the Company's oil and gas operations.

Year Ended December 31, 1998

	U.S.	Canada ($ in thousands)	Combined
Oil and gas sales	$ 248,909	$ 7,978	$ 256,887
Production costs (a)	(57,663)	(1,834)	(59,497)
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 (b)	285,981	5,673	291,654
Results of operations from oil and gas producing activities	$ (476,666)	$ (6,934)	$ (483,600)

Six Months Ended December 31, 1997

	U.S.	Canada ($ in thousands)	Combined
Oil and gas sales	$ 95,657	$ —	$ 95,657
Production costs (a)	(10,094)	—	(10,094)
Impairment of oil and gas properties	(110,000)	—	(110,000)
Depletion and depreciation	(60,408)	—	(60,408)
Imputed income tax (provision) benefit (b)	31,817	—	31,817
Results of operations from oil and gas producing activities	$ (53,028)	$ —	$ (53,028)

Year Ended June 30, 1997

	U.S.	Canada ($ in thousands)	Combined
Oil and gas sales	$ 192,920	$ —	$ 192,920
Production costs (a)	(15,107)	—	(15,107)
Impairment of oil and gas properties	(236,000)	—	(236,000)
Depletion and depreciation	(103,264)	—	(103,264)
Imputed income tax (provision) benefit (b)	60,544	—	60,544
Results of operations from oil and gas producing activities	$ (100,907)	$ —	$ (100,907)

Year Ended June 30, 1996

	U.S.	Canada ($ in thousands)	Combined
Oil and gas sales	$ 110,849	$ —	$ 110,849
Production costs (a)	(8,303)	—	(8,303)
Impairment of oil and gas properties	—	—	—
Depletion and depreciation	(50,899)	—	(50,899)
Imputed income tax (provision) benefit (b)	(18,335)	—	(18,335)
Results of operations from oil and gas producing activities	$ 33,312	$ —	$ 33,312

(a) Production costs include lease operating expenses and production taxes.

(b) The imputed income tax provision is hypothetical (at the statutory rate) and determined without regard to the Company's 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. During 1998, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues from the Company's proved reserves, net of related income tax considerations, resulting in a writedown in the carrying value of oil and gas properties of $826 million. At December 31, 1997, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues for the Company's proved reserves, net of related income tax considerations, resulting in a writedown in the carrying value of oil and gas properties of $110 million. At June 30, 1997, capitalized costs of oil and gas properties also exceeded the estimated present value of future net revenues for the Company's proved reserves, net of related income tax considerations, resulting in a writedown in the carrying value of oil and gas properties of $236 million.

Oil and Gas Reserve Quantities (unaudited)

The reserve information presented below is based upon reports prepared by independent petroleum engineers and the Company's petroleum engineers. As of December 31, 1998, Williamson Petroleum Consultants, Inc. ("Williamson"), Ryder Scott Company Petroleum Engineers, H.J. Gruy and Associates, Inc. and the Company's internal reservoir engineers evaluated 63%, 12%, 1% and 24% of the Company's combined discounted future net revenues from the Company's estimated proved reserves, respectively. As of December 31, 1997, Williamson, Porter Engineering Associates, Netherland, Sewell & Associates, Inc. and internal reservoir engineers evaluated approximately 53%, 42%, 3% and 2% the Company's combined discounted future net revenues from the Company's estimated proved reserves, respectively. As of June 30, 1997 and 1996, the reserves evaluated by Williamson constituted approximately 41% and 99% of the company's combined discounted future net revenues from the Company's estimated proved reserves, respectively, with the remaining reserves being evaluated internally. The reserves evaluated internally in fiscal 1997 were subsequently evaluated by Williamson with a variance of approximately 4% of total proved reserves. The information is presented in accordance with regulations prescribed by the Securities and Exchange Commission. The Company emphasizes that reserve estimates are inherently imprecise. The Company's 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. As of December 31, 1997, all of the Company's oil and gas reserves were located in the United States.

Presented below is a summary of changes in estimated reserves of the Company for 1998, the six months ended December 31, 1997 and for the fiscal years 1997 and 1996:

December 31, 1998

	U.S.		Canada		Combined	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved reserves, beginning of period	18,226	339,118	—	—	18,226	339,118
Extensions, discoveries and other additions	3,448	90,879	—	—	3,448	90,879
Revisions of previous estimates	(4,082)	(60,477)	—	—	(4,082)	(60,477)
Production	(5,975)	(86,681)	(1)	(7,740)	(5,976)	(94,421)
Sale of reserves-in-place	(30)	(3,515)	—	—	(30)	(3,515)
Purchase of reserves-in-place	10,973	444,694	34	239,513	11,007	684,207
Proved reserves, end of period	22,560	724,018	33	231,773	22,593	955,791
Proved developed reserves:						
Beginning of period	10,087	178,082	—	—	10,087	178,082
End of period	18,003	552,953	33	105,990	18,036	658,943

December 31, 1997

	U.S.		Canada		Combined	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved reserves, beginning of period	17,373	298,766	—	—	17,373	298,766
Extensions, discoveries and other additions	5,573	68,813	—	—	5,573	68,813
Revisions of previous estimates	(3,428)	(24,189)	—	—	(3,428)	(24,189)
Production	(1,857)	(27,327)	—	—	(1,857)	(27,327)
Sale of reserves-in-place	—	—	—	—	—	—
Purchase of reserves-in-place	565	23,055	—	—	565	23,055
Proved reserves, end of period	18,226	339,118	—	—	18,226	339,118
Proved developed reserves:						
Beginning of period	7,324	151,879	—	—	7,324	151,879
End of period	10,087	178,082	—	—	10,087	178,082

June 30, 1997

	U.S.		Canada		Combined	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved reserves, beginning of period	12,258	351,224	—	—	12,258	351,224
Extensions, discoveries and other additions	13,874	147,485	—	—	13,874	147,485
Revisions of previous estimates	(5,989)	(137,938)	—	—	(5,989)	(137,938)
Production	(2,770)	(62,005)	—	—	(2,770)	(62,005)
Sale of reserves-in-place	—	—	—	—	—	—
Purchase of reserves-in-place	—	—	—	—	—	—
Proved reserves, end of period	17,373	298,766	—	—	17,373	298,766
Proved developed reserves:						
Beginning of period	3,648	144,721	—	—	3,648	144,721
End of period	7,324	151,879	—	—	7,324	151,879

June 30, 1996

	U.S.		Canada		Combined	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved reserves, beginning of period	5,116	211,808	—	—	5,116	211,808
Extensions, discoveries and other additions	8,781	158,052	—	—	8,781	158,052
Revisions of previous estimates	(669)	12,987	—	—	(669)	12,987
Production	(1,413)	(51,710)	—	—	(1,413)	(51,710)
Sale of reserves-in-place	—	—	—	—	—	—
Purchase of reserves-in-place	443	20,087	—	—	443	20,087
Proved reserves, end of period	12,258	351,224	—	—	12,258	351,224
Proved developed reserves:						
Beginning of period	1,973	77,764	—	—	1,973	77,764
End of period	3,648	144,721	—	—	3,648	144,721

During 1998, the Company acquired approximately 750 Bcfe of proved reserves through merger or through purchases of oil and gas properties. The total consideration given for the acquisitions was 30.8 million shares of Company common stock, $280 million of cash, the assumption of $205 million of debt, and the incurrence of approximately $20 million of other acquisition related costs. Also during 1998, the Company recorded downward revisions to the December 31, 1997 estimates of approximately 4,082 MBbl and 60,477 MMcf, or approximately 85 Bcfe. These reserve revisions were primarily attributable to lower oil and gas prices at December 31, 1998. The weighted average prices used to value the Company's reserves at December 31, 1998 were $10.48 per barrel of oil and $1.68 per Mcf of gas, as compared to the prices used at December 31, 1997 of $17.62 per barrel of oil and $2.29 per Mcf of gas.

For the six months ended December 31, 1997, the Company recorded downward revisions to the June 30, 1997 reserve estimates of approximately 3,428 MBbl and 24,189 MMcf, or approximately 45 Bcfe. The reserve revisions were primarily attributable to lower than expected results from development drilling and production which eliminated certain previously established proven reserves.

On December 16, 1997, Chesapeake acquired AnSon Production Corporation, a privately owned oil and gas producer based in Oklahoma City. Consideration for this acquisition was approximately $43 million. The Company estimates that it acquired approximately 26.4 Bcfe in connection with this acquisition.

For the fiscal year ended June 30, 1997, the Company recorded downward revisions to the previous year's reserve estimates of approximately 5,989 MBbl and 137,938 MMcf, or approximately 174 Bcfe. The reserve revisions were primarily attributable to the decrease in oil and gas prices between periods, higher drilling and completion costs, and unfavorable developmental drilling and production results during fiscal 1997. Specifically, the Company recorded aggregate downward adjustments to proved reserves of 159 Bcfe for the Knox, Giddings and Louisiana Trend areas.

On April 30, 1996, the Company purchased interests in certain producing and non-producing oil and gas properties, including approximately 14,000 net acres of unevaluated leasehold, from Amerada Hess Corporation for $37.8 million. The properties are located in the Knox and Golden Trend fields of southern Oklahoma, most of which are operated by the Company. In fiscal 1996 the reserves acquired from Amerada Hess Corporation were included in both "extensions, discoveries and other additions" and "purchase of reserves-in-place". The fiscal 1996 presentation has been restated to remove the acquired reserves from "extensions, discoveries and other additions" with a corresponding offset to "revisions of previous estimate". This revision resulted in no net change to total oil and gas reserves.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

Statement of Financial Accounting Standards No. 69 ("SFAS 69") prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company 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 Company's reserve values were calculated using weighted average prices at December 31, 1998 of $10.48 per barrel of oil and $1.68 per Mcf of natural gas. If prices in future periods are below the average realized levels at December 31, 1998, future impairment charges will likely be incurred.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect the Company's 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 the Company's 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 ($ in thousands)	Combined
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, 1997

	U.S.	Canada ($ in thousands)	Combined
Future cash inflows (b)	$ 1,100,807	$ —	$1,100,807
Future production costs	(223,030)	—	(223,030)
Future development costs	(158,387)	—	(158,387)
Future income tax provision	(108,027)	—	(108,027)
Net future cash flows	611,363	—	611,363
Less effect of a 10% discount factor	(181,253)	—	(181,253)
Standardized measure of discounted future net cash flows	$ 430,110	$ —	$ 430,110
Discounted (at 10%) future net cash flows before income taxes	$ 466,509	$ —	$ 466,509

June 30, 1997

	U.S.	Canada ($ in thousands)	Combined
Future cash inflows (c)	$ 954,839	$ —	$ 954,839
Future production costs	(190,604)	—	(190,604)
Future development costs	(152,281)	—	(152,281)
Future income tax provision	(104,183)	—	(104,183)
Net future cash flows	507,771	—	507,771
Less effect of a 10% discount factor	(92,273)	—	(92,273)
Standardized measure of discounted future net cash flows	$ 415,498	$ —	$ 415,498
Discounted (at 10%) future net cash flows before income taxes	$ 437,386	$ —	$ 437,386

June 30, 1996

	U.S.	Canada ($ in thousands)	Combined
Future cash inflows (d)	$ 1,101,642	$ —	$1,101,642
Future production costs	(168,974)	—	(168,974)
Future development costs	(137,068)	—	(137,068)
Future income tax provision	(135,543)	—	(135,543)
Net future cash flows	660,057	—	660,057
Less effect of a 10% discount factor	(198,646)	—	(198,646)
Standardized measure of discounted future net cash flows	$ 461,411	$ —	$ 461,411
Discounted (at 10%) future net cash flows before income taxes	$ 547,016	$ —	$ 547,016

(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 $17.62 per barrel of oil and $2.29 per Mcf of gas.

(c) Calculated using weighted average prices of $18.38 per barrel of oil and $2.12 per Mcf of gas.

(d) Calculated using weighted average prices of $20.90 per barrel of oil and $2.41 per Mcf of gas.

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

December 31, 1998

	U.S.	Canada ($ in thousands)	Combined
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, 1997

	U.S.	Canada ($ in thousands)	Combined
Standardized measure, beginning of period	$ 415,498	$ —	$ 415,498
Sales of oil and gas produced, net of production costs	(85,563)	—	(85,563)
Net changes in prices and production costs	26,106	—	26,106
Extensions and discoveries, net of production and development costs	92,597	—	92,597
Changes in future development costs	(7,422)	—	(7,422)
Development costs incurred during the period that reduced future development costs	47,703	—	47,703
Revisions of previous quantity estimates	(62,655)	—	(62,655)
Purchase of reserves-in-place	25,236	—	25,236
Sales of reserves-in-place	—	—	—
Accretion of discount	43,739	—	43,739
Net change in income taxes	(14,510)	—	(14,510)
Changes in production rates and other	(50,619)	—	(50,619)
Standardized measure, end of period	$ 430,110	$ —	$ 430,110

June 30, 1997

	U.S.	Canada ($ in thousands)	Combined
Standardized measure, beginning of period	$ 461,411	$ —	$ 461,411
Sales of oil and gas produced, net of production costs	(177,813)	—	(177,813)
Net changes in prices and production costs	(99,234)	—	(99,234)
Extensions and discoveries, net of production and development costs	287,068	—	287,068
Changes in future development costs	(12,831)	—	(12,831)
Development costs incurred during the period that reduced future development costs	46,888	—	46,888
Revisions of previous quantity estimates	(199,738)	—	(199,738)
Purchase of reserves-in-place	—	—	—
Sales of reserves-in-place	—	—	—
Accretion of discount	54,702	—	54,702
Net change in income taxes	63,719	—	63,719
Changes in production rates and other	(8,674)	—	(8,674)
Standardized measure, end of period	$ 415,498	$ —	$ 415,498

June 30, 1996

	U.S.	Canada	Combined
		($ in thousands)	
Standardized measure, beginning of period	$ 159,911	$ —	$ 159,911
Sales of oil and gas produced, net of production costs	(102,546)	—	(102,546)
Net changes in prices and production costs	88,729	—	88,729
Extensions and discoveries, net of production and development costs	275,916	—	275,916
Changes in future development costs	(11,201)	—	(11,201)
Development costs incurred during the period that reduced future development costs	43,409	—	43,409
Revisions of previous quantity estimates	12,728	—	12,728
Purchase of reserves-in-place	29,641	—	29,641
Sales of reserves-in-place	—	—	—
Accretion of discount	18,814	—	18,814
Net change in income taxes	(57,382)	—	(57,382)
Changes in production rates and other	3,392	—	3,392
Standardized measure, end of period	$ 461,411	$ —	$ 461,411

12. Transition Period Comparative Data

The following table presents certain financial information for the twelve months ended December 31, 1998 and 1997, and the six months ended December 31, 1997 and 1996, respectively:

	Twelve Months Ended December 31,		Six Months Ended December 31,	
	1998	1997 (unaudited)	1997	1996 (unaudited)
	($ in thousands, except per share data)			
Revenues	$ 377,946	$ 302,804	$153,898	$ 120,186
Gross profit (loss)[(a)]	$ (856,197)	$ (309,041)	$(93,092)	$ 42,946
Income (loss) before income taxes and extraordinary item	$ (920,520)	$ (251,150)	$(31,574)	$ 39,246
Income taxes	—	(17,898)	—	14,325
Income (loss) before extraordinary item	(920,520)	(233,252)	(31,574)	24,921
Extraordinary item	(13,334)	(177)	—	(6,443)
Net income (loss)	$ (933,854)	$ (233,429)	$(31,574)	$ 18,478
Earnings per share – basic				
Income (loss) before extraordinary item	$ (9.83)	$ (3.30)	$ (0.45)	$ 0.40
Extraordinary item	(0.14)	—	—	(0.10)
Net income (loss)	$ (9.97)	$ (3.30)	$ (0.45)	$ 0.30
Earnings per share – assuming dilution				
Income (loss) before extraordinary item	$ (9.83)	$ (3.30)	$ (0.45)	$ 0.38
Extraordinary item	(0.14)	—	—	(0.10)
Net income (loss)	$ (9.97)	$ (3.30)	$ (0.45)	$ 0.28
Weighted average common shares outstanding (in 000's)				
Basic	94,911	70,672	70,835	61,985
Assuming dilution	94,911	70,672	70,835	66,300

(a) Total revenue excluding interest and other income, less total costs and expenses excluding interest and other expense.

13. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 1998, the six months ended December 31, 1997 and fiscal 1997 are as follows ($ in thousands except per share data):

	Quarter Ended			
	March 31, 1998	June 30, 1998	September 30, 1998	December 31, 1998
Net sales	$ 76,765	$109,310	$106,338	$ 85,533
Gross profit (loss)[a]	(246,036)	(218,645)	13,650	(405,166)
Net income (loss) before extraordinary item	(256,500)	(234,739)	(4,149)	(425,132)
Net income (loss)	(256,500)	(248,073)	(4,149)	(425,132)
Income (loss) per share before extraordinary item:				
Basic	(3.19)	(2.29)	(0.08)	(4.44)
Diluted	(3.19)	(2.29)	(0.08)	(4.44)

	Quarter Ended	
	September 30, 1997	December 31, 1997
Net sales	$ 72,532	$ 81,366
Gross profit (loss)[a]	8,210	(101,302)
Net Income (loss)	5,513	(37,087)
Net Income (loss) per share before extraordinary item:		
Basic	.08	(.52)
Diluted	.08	(.52)

	Quarter Ended			
	September 30, 1996	December 31, 1996	March 31, 1997	June 30, 1997
Net sales	$ 48,937	$ 71,249	$ 79,809	$ 69,097
Gross profit (loss)[a]	14,889	28,057	25,737	(241,686)
Income (loss) before extraordinary item	8,204	16,717	16,105	(217,783)
Net income (loss)	8,204	10,274	15,928	(217,783)
Income (loss) per share before extraordinary item:				
Basic	.14	.26	.23	(3.12)
Diluted	.13	.25	.22	(3.12)

(a) Total revenue excluding interest and other income, less total costs and expenses excluding interest and other expense.

Capitalized costs, less accumulated amortization and related deferred income taxes, cannot 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. At December 31, 1998, June 30, 1998, March 31, 1998, December 31, 1997 and June 30, 1997, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues for the Company's proved reserves, net of related income tax considerations, resulting in writedowns in the carrying value of oil and gas properties of $360 million, $216 million, $250 million, $110 million and $236 million, respectively.

During the fourth quarter of 1998, the Company incurred a $55 million impairment charge to adjust certain non-oil and gas assets to their estimated fair values. Of this amount, $30 million related to the Company's investment in preferred stock of Gothic Energy Corporation, and the remainder was related to certain of the Company's gas processing and transportation assets located in Louisiana.

14. Acquisitions

During 1998, the Company acquired approximately 750 Bcfe of proved reserves through merger or through purchases of oil and gas properties. The total consideration given for the acquisitions was $280 million of cash, 30.8 million shares of Company common stock, the assumption of $205 million of debt, and the incurrence of approximately $20 million of other acquisition related costs.

In March 1998, the Company acquired Hugoton Energy Corporation ("Hugoton") pursuant to a merger by issuing 25.8 million shares of the Company's common stock in exchange for 100% of Hugoton's common stock. The acquisition of Hugoton was accounted for using the purchase method as of March 1, 1998, and the results of operations of Hugoton have been included since that date.

The following unaudited pro forma information has been prepared assuming Hugoton had been acquired as of the beginning of the periods presented. The pro forma information is presented for informational purposes only and is not necessarily indicative of what would have occurred if the acquisition had been made as of those dates. In addition, the pro forma information is not intended to be a projection of future results and does not reflect the efficiencies expected to result from the integration of Hugoton.

Pro Forma Information (Unaudited)

	Year Ended December 31,	
	1998	1997
	($ in thousands, except per share data)	
Revenues	$ 387,638	$ 379,546
Loss before extraordinary item	(921,969)	(215,350)
Net loss	(935,303)	(215,527)
Loss before extraordinary item per common share	(9.41)	(2.23)
Net loss per common share	(9.55)	(2.23)

The Company acquired other businesses and oil and gas properties during the twelve months ended December 31, 1998. The results of operations of each of these businesses and properties, taken individually, were not material in relation to the Company's consolidated results of operations.

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, 1997:					
Allowance for doubtful accounts	$ 387	$ 40	$ 264	$ —	$ 691
Valuation allowance for deferred tax assets	$ 64,116	$ 13,818	$ —	$ —	$ 77,934
June 30, 1997:					
Allowance for doubtful accounts	$ 340	$ 299	$ —	$ 252	$ 387
Valuation allowance for deferred tax assets	$ —	$ 64,116	$ —	$ —	$ 64,116
June 30, 1996:					
Allowance for doubtful accounts	$ 452	$ 114	$ —	$ 226	$ 340

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 the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 1999.

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 the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 1999.

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 the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 1999.

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 the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 1999.

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

2. *Financial Statement Schedules.* No financial statement schedules are filed with this report as no schedules are applicable or required.

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

Exhibit Number	**Description**
3.1	— Registrant's Certificate of Incorporation as amended. Incorporated herein by reference to Exhibit 3.1 to Registrant's Amendment No. 1 to Form S-3 registration statement (No. 333-57235).
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).
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 4.1.3 to Registrant 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 9No. 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.

4.9 — Registration Rights Agreement dated October 22, 1997 as amended by Amendment No. 1 dated December 22, 1997 between Chesapeake Energy Corporation and Charles E. Davidson. Incorporated herein by reference to Exhibit 4.9 and 4.10 to Registrant's registration statement on Form S-4 (No. 333-48735).

4.10 — Registration Rights Agreement between Chesapeake Energy Corporation and certain shareholders of Hugoton Energy Corporation. Incorporated herein by reference to Registrant's registration statement on Form S-4 (No. 333-48735).

4.11 — Registration Rights Agreement as of April 22, 1998 among the Registrant and Donaldson, Lufkin & Jenrette Securities Corporation, Morgan Stanley & Co. Incorporated, Bear Stearns & Co. Inc., Lehman Brothers Inc. and J.P. Morgan Securities Inc., with respect to 7% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 4.11 to Registrant's quarterly report on Form 10-Q for the quarter ended March 31, 1998.

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.

10.1.4.1 — Amendment to the Chesapeake Energy Corporation 1996 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.4.1 to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1996.

10.2.1† — Amended and Restated Employment Agreement dated as of July 1, 1998 between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit

10.2.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.

10.2.2† — Amended and Restated Employment Agreement dated as of July 1, 1998 between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.

10.2.3*† — Amended and Restated Employment Agreement dated as of July 1, 1998 between Marcus C. Rowland and Chesapeake Energy Corporation.

10.2.4† — Employment Agreement dated as of July 1, 1997 between Steven C. Dixon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.4 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1997.

10.2.5† — Employment Agreement dated as of July 1, 1997 between J. Mark Lester and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.5 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.

10.2.6† — Employment Agreement dated as of July 1, 1997 between Henry J. Hood and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.6 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.

10.2.7† — Employment Agreement dated as of July 1, 1997 between Ronald A. Lefaive and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.7 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.

10.2.8† — Employment Agreement dated as of July 1, 1997 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.

10.2.9* — Amendment to Employment Agreements of Steven C. Dixon, J. Mark Lester, Henry J. Hood, Ronald A. Lefaive and Martha A. Burger dated as of July 1, 1997.

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* — Second Amended and Restated Loan Agreement between Aubrey K. McClendon and Chesapeake Energy Marketing, Inc., dated effective December 31, 1998.

10.4.2* — Second Amended and Restated Loan Agreement between Tom L. Ward and Chesapeake Energy Marketing, Inc., dated effective December 31, 1998.

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.

10.9 — Indemnity and Stock Registration Agreement, as amended by First Amendment (Revised) thereto, dated as of February 12, 1993, and as amended by Second Amendment thereto dated as of October 20, 1995, among Chesapeake Energy Corporation, Chesapeake Operating, Inc., Chesapeake Investments, TLW Investments, Inc., et al. Incorporated herein by reference to Exhibit 10.35 to Registrant's annual report on Form 10-K for the year ended June 30, 1993 and Exhibit 10.4.1 to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1995.

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 Petroleum Engineers

27* — Financial Data Schedule

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* Filed herewith.

† Management contract or compensatory plan or arrangement.

(b) Reports on Form 8-K

During the quarter ended December 31, 1998, the Company filed the following Current Reports on Form 8-K dated:

October 7, 1998 announcing a significant Tuscaloosa discovery.

October 23, 1998 providing a status report on drilling activity.

November 9, 1998 announcing that it had agreed to tender its 19.9% stake in Pan East Petroleum Corp. to Poco Petroleums Ltd. and had agreed to a property exchange with Pan East.

November 18, 1998 reporting 1998 third quarter results.

December 8, 1998 announcing completion of a significant Tuscaloosa discovery.

December 17, 1998 announcing capital budget and suspension of dividend of its preferred stock.

December 22, 1998 responding to Union Pacific Resources Corporation's press release regarding pending litigation.

SIGNATURES

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

CHESAPEAKE ENERGY CORPORATION

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

Date: March 30, 1999

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)	March 30, 1999
/s/ TOM L. WARD Tom L. Ward	President, Chief Operating Officer and Director (Principal Executive Officer)	March 30, 1999
/s/ MARCUS C. ROWLAND Marcus C. Rowland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 30, 1999
/s/ RONALD A. LEFAIVE Ronald A. Lefaive	Senior Vice President – Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 30, 1999
/s/ EDGAR F. HEIZER, JR. Edgar F. Heizer, Jr.	Director	March 30, 1999
/s/ BREENE M. KERR Breene M. Kerr	Director	March 30, 1999
/s/ SHANNON T. SELF Shannon T. Self	Director	March 30, 1999
/s/ FREDERICK B. WHITTEMORE Frederick B. Whittemore	Director	March 30, 1999
/s/ WALTER C. WILSON Walter C. Wilson	Director	March 30, 1999

Corporate Information

Calendar Year Stock Data

(in $)	*High*	*Low*	*Last*
1996			
First Quarter	16.50	10.67	15.42
Second Quarter	30.38	15.50	29.96
Third Quarter	34.00	21.00	31.31
Fourth Quarter	34.13	25.69	27.82
1997			
First Quarter	31.50	19.88	20.88
Second Quarter	22.38	9.25	9.94
Third Quarter	11.50	6.31	11.38
Fourth Quarter	13.44	6.81	7.56
1998			
First Quarter	7.75	5.50	5.88
Second Quarter	6.00	3.88	4.00
Third Quarter	4.06	1.13	1.19
Fourth Quarter	2.63	0.75	0.88

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.chesapeake-energy.com or by contacting Thomas S. Price, Jr., at the corporate office by calling (405) 879-9257. E-mail requests may be directed to tprice@chesapeake-energy.com.

Common Stock

Chesapeake Energy Corporation's common stock is listed on the New York Stock Exchange under the symbol CHK. As of March 15, 1999, there were approximately 28,000 beneficial owners of the common stock.

Common Stock Dividends

The company initiated a quarterly dividend with the payment of $0.02 per common share in July 1997. The dividend was suspended in July 1998. 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

The information contained in this annual report includes certain forward-looking statements. When used in this document, the words "potential," "budgeted," "anticipates," "expects," "believes," "goals," "objectives," "projects," and similar expressions are intended to identify forward-looking statements. It is important to note that Chesapeake's actual results could differ materially from those projected by such forward-looking statements. Important factors that could cause actual results to differ materially from those projected in the forward-looking statements include, but are not limited to, the following: production variances from expectations, risks related to exploration and development drilling outcomes, uncertainties about estimates of reserves, volatility of oil and natural gas prices, the need to develop and replace reserves, the substantial capital expenditures required to fund its operations, the risk that aforementioned and subsequent acquisitions will fail to produce expected unit cost reductions and increased commercial oil and gas production and reserves, environmental risks, drilling and operating risks, competition, government regulation, and the ability of the company to implement its revised business strategy. Chesapeake's actual results could also differ materially due to risks associated with the integration of its business and operations with those various companies that it has acquired in a relatively short time frame. These risks include, but are not limited to, the risk that the aforementioned and subsequent acquisitions will fail to produce expected efficiencies, unit cost reductions and increases in commercial oil and gas production and reserves. These and other risks are described in the company's documents and reports that are available from the United States Securities and Exchange Commission, including the report filed on Form 10-K for the year ended December 31, 1998.

CHESAPEAKE ENERGY CORPORATION

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Oklahoma City, Oklahoma 73118
www.chesapeake-energy.com