CHESAPEAKE ENERGY CORPORATION 1996

CHESAPEAKE Annual Report

SELECTED FINANCIAL DATA

Year Ended June 30,	1996	1995	1994	1993	1992
Income Data *($ in thousands, except per share data)*					
Oil and gas sales	$ 110,849	$ 56,983	$ 22,404	$ 11,602	$ 10,520
Gas marketing sales	28,428	–	–	–	–
Service operations and other	10,145	10,360	7,420	6,406	8,198
Total revenues	149,422	67,343	29,824	18,008	18,718
Production expenses and taxes	8,303	4,256	3,647	2,890	2,103
Gas marketing expenses	27,452	–	–	–	–
Service operations	4,895	7,747	5,199	3,653	4,113
Oil and gas depreciation, depletion and amortization	50,899	25,410	8,141	4,184	2,910
Other depreciation and amortization	3,157	1,765	1,871	557	974
General and administrative	4,828	3,578	3,135	4,906	3,314
Interest and other	13,679	6,627	2,676	2,282	2,577
Total expenses	113,213	49,383	24,669	18,472	15,991
Income (loss) before income taxes	36,209	17,960	5,155	(464)	2,727
Income tax expense (benefit)	12,854	6,299	1,250	(99)	1,337
Net income (loss)	$ 23,355	$ 11,661	$ 3,905	$ (365)	$ 1,390
Earnings (loss) per share	$ .80	$ .42	$ .16	$ (.04)	$ .10
Weighted average shares outstanding	29,171	27,936	24,120	16,776	13,955
Property Data *($ in thousands)*					
Oil reserves (MBbls)	12,258	5,116	4,154	9,622	11,147
Gas reserves (MMcf)	351,224	211,808	117,066	79,763	68,618
Reserves in equivalent thousand barrels	70,795	40,417	23,665	22,915	22,583
Reserves in equivalent million cubic feet	424,775	242,505	141,992	137,495	135,500
Future net revenues discounted at 10% (before tax)	$ 547,016	$ 188,137	$ 141,249	$ 141,665	$ 162,713
Oil production (MBbls)	1,413	1,139	537	276	374
Gas production (MMcf)	51,710	25,114	6,927	2,677	1,252
Production in equivalent thousand barrels	10,031	5,325	1,692	722	583
Production in equivalent million cubic feet	60,190	31,947	10,152	4,333	3,496
Average oil price (per Bbl)	$ 17.85	$ 17.36	$ 15.09	$ 20.20	$ 21.85
Average gas price (Mcf)	$ 1.66	$ 1.48	$ 2.06	$ 2.25	$ 1.88
Average gas equivalent price (per Mcfe)	$ 1.84	$ 1.78	$ 2.21	$ 2.68	$ 3.01

Chesapeake Energy Corporation is an independent oil and gas exploration company headquartered in Oklahoma City. The company utilizes advanced drilling and completion techniques to develop significant new oil and natural gas discoveries in major onshore producing areas of the United States. Chesapeake is traded on the New York Stock Exchange under the symbol CHK.

CHESAPEAKE ENERGY CORPORATION

CHESAPEAKE Annual Report

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More value

can be created

FUNDAMENTAL BELIEF Nº. 1

by discovering

new oil and

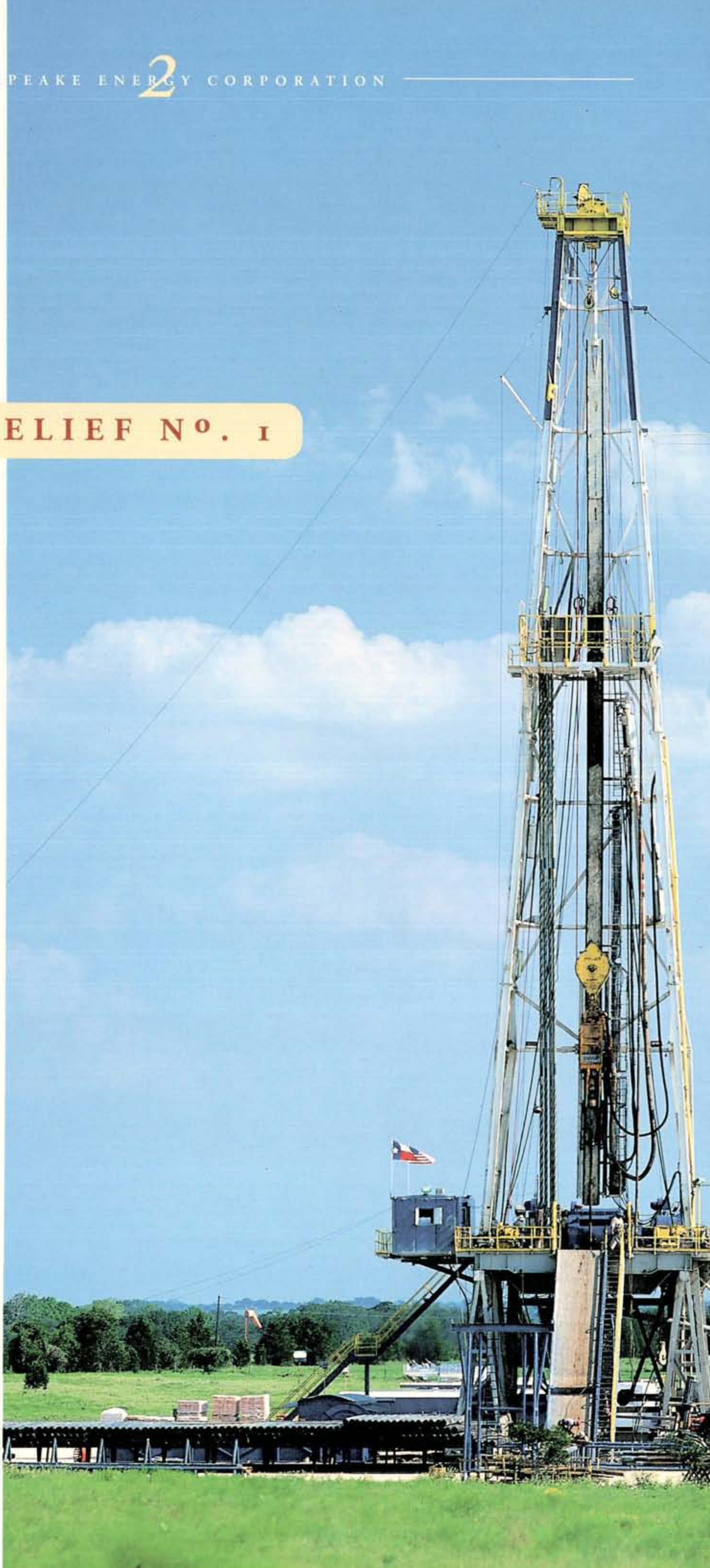
gas reserves

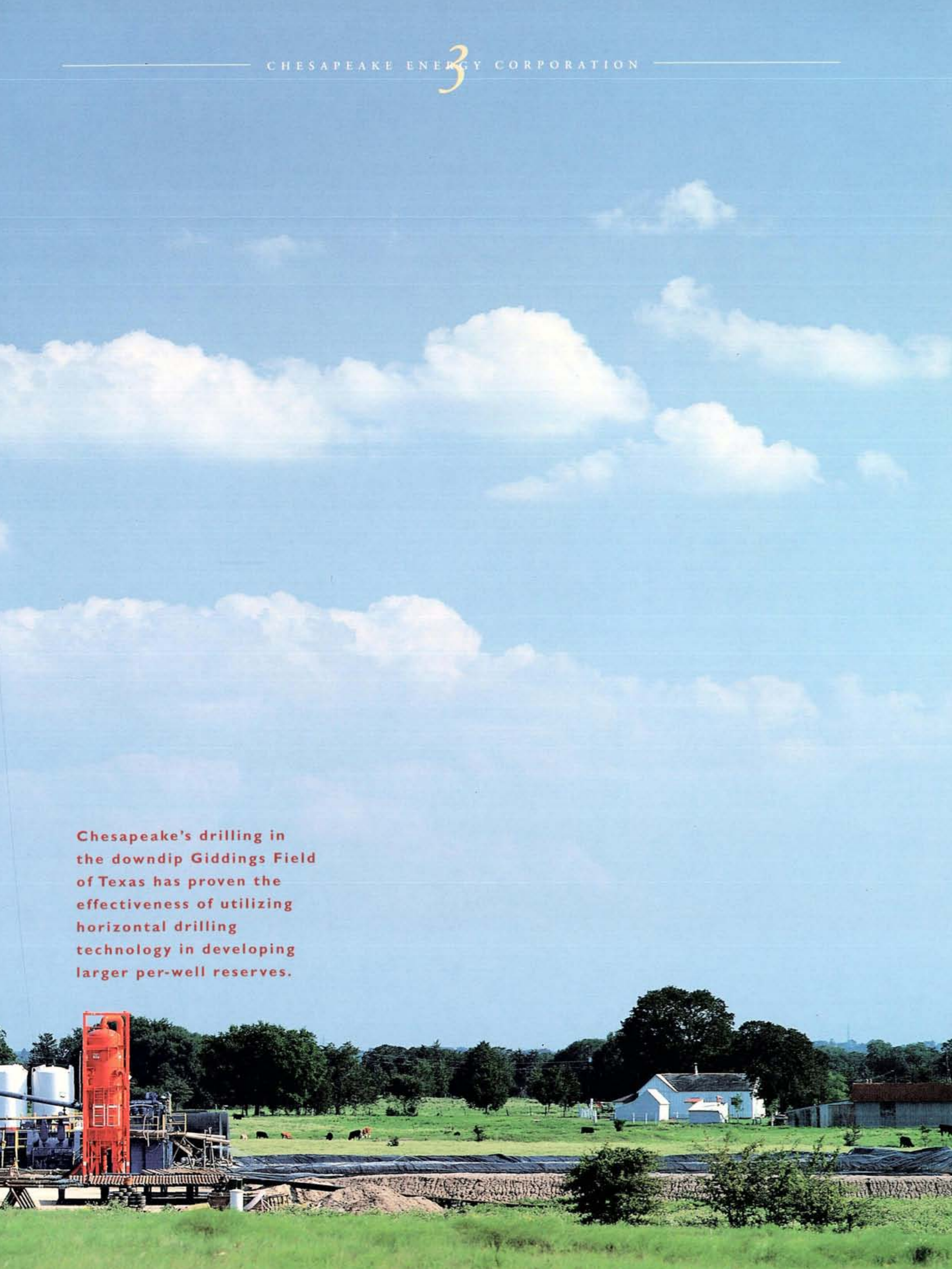
than by

purchasing

existing

reserves.





Chesapeake's drilling in the downdip Giddings Field of Texas has proven the effectiveness of utilizing horizontal drilling technology in developing larger per-well reserves.

CHESAPEAKE CONTINUES to lead the independent oil and

CHESAPEAKE'S CONTINUED PROGRESS

natural gas industry in creating shareholder value.

Our company has led the sector in total shareholder return for the past two years – 544% in fiscal 1995 and 431% in fiscal 1996. We believe this success is attributable to our focused and clearly articulated strategy and to our experienced and highly motivated management team, supported by technical teams second to none.

Since Chesapeake's inception in 1989, our business strategy has been "growth through the drillbit." Using this strategy, the company has rapidly expanded its reserves and production through the acquisition and development of large blocks of undeveloped acreage overlying deep, underdeveloped geological reservoirs such as fractured carbonates. We are attracted to these reservoirs because they offer low geological risk, large reserve potential, and the opportunity to earn attractive economic returns through the application of advanced drilling and completion techniques.

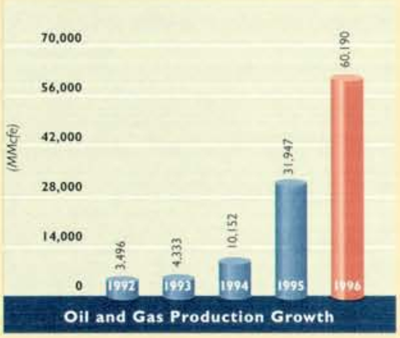
Our successful implementation of this strategy has enabled Chesapeake to become one of the premier independent energy producers. As the company has matured, we have developed the following five competitive advantages that we believe are the keys to continued growth:

- Growth through the drillbit business strategy;
- Five-year inventory of future drilling opportunities created by establishing dominant leasehold positions;
- Technological leadership resulting in new oil and gas discoveries and a lower cost structure;
- Superior profit margins that generate high levels of cash flow per unit of production to reinvest in growing our company; and
- Close alignment of shareholder and management interests resulting from management's 40% ownership stake.

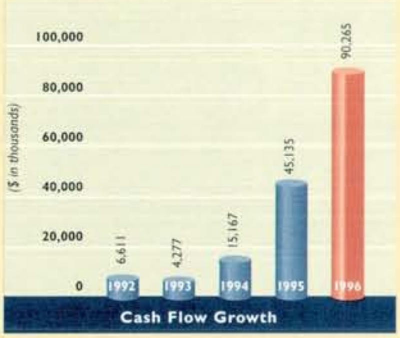
Before explaining why we believe these competitive advantages can continue to generate attractive returns to our shareholders, we will highlight our results for fiscal 1996. During the year, Chesapeake:

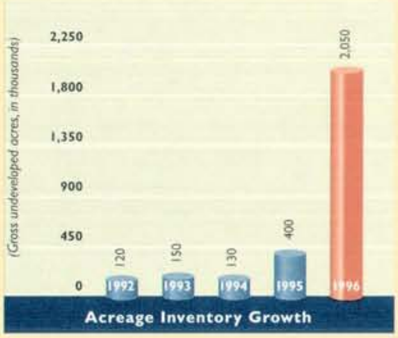
- Increased oil and natural gas production 88% to 60 Bcfe;
- Increased total revenues 122% to $149.4 million;
- Increased earnings 100% to $23.4 million and earnings per share 91% to $0.80;
- Increased operating cash flow 100% to $90.3 million;
- Increased proved reserves 76% to 425 Bcfe and increased SEC-PV10 value 193% to $547 million.

1996's ACHIEVEMENTS



These graphs illustrate Chesapeake's dynamic five-year record of growth.





TO BECOME A LEADER in any industry, and more importantly,

CHESAPEAKE'S COMPETITIVE ADVANTAGES

to remain a leader, a company must develop distinctive core competencies that distinguish it from its competitors. This is especially true in the independent energy sector where more than 200 major and independent public companies compete to find, develop, and produce oil and natural gas.

TOP OPERATORS - ONSHORE USA

Rank	Operator name	Rig Count	Avg. Depth
1.	Union Pacific	36	14,555
2.	Texaco	36	10,160
3.	Enron	29	10,548
4.	**Chesapeake**	**23**	**16,012**
5.	Amoco	22	10,308
6.	Parker & Parsley	22	7,844
7.	Chevron	19	9,492
8.	Sonat	17	12,476
9.	Marathon	17	12,182
10.	Burlington	13	10,240
		243	11,082

Source: Petroleum Information: June 30, 1996

Growth through the drillbit

COMPETITIVE ADVANTAGE Nº. 1

The rewards for Chesapeake and its shareholders are generated by the company's expertise in producing large amounts of oil and gas from unconventional reservoirs. These reservoirs have traditionally been uneconomic to develop because of their geological complexity. Using new technologies, however, we can now profitably exploit these reservoirs and generate a rapid return on our investments.

We have elected to build our company through our expertise with the drillbit rather than by acquiring other companies' producing properties. This strategy makes Chesapeake fundamentally different and more profitable than most independent energy companies for three reasons.

First, this strategy enables our company to capture more upside by drilling new wells that have much higher productive capabilities than older wells. In Chesapeake's project areas, new wells can develop reserves with a value of up to five times the cost of drilling such wells. They provide a much higher return on investment than can be generated by purchasing partially depleted wells from other companies and then attempting to stimulate marginal production increases.

Secondly, there is less competition for good exploration ideas in Chesapeake's areas of operation because most major oil and natural gas companies have significantly reduced domestic onshore exploration efforts, and many independent producers have focused on producing property acquisitions. With less competition, our company has a greater opportunity to leverage its exploration expertise into new areas that could significantly increase shareholder value.

The third reason for Chesapeake's growth through the drillbit strategy is the efficiency created from owning new wells. Just as in operating any new equipment, operating a newly drilled well is less expensive than operating an older well which requires ongoing maintenance.

Consequently, the company's administrative and production costs per unit of oil and natural gas produced have been the lowest in the industry. This cost structure provides Chesapeake with more cash flow to reinvest in its drilling program, thereby providing a key component of the funding required to continue the company's growth.

Chesapeake's growth through the drillbit strategy has resulted in high returns on investment, greater reserve recovery, and increased efficiency and cash flow.

The success of this growth through the drillbit strategy is most evident in Chesapeake's oil and natural gas production growth. In the fourth quarter of fiscal 1993, our first full quarter as a public company, Chesapeake produced 1.1 Bcfe. By the fourth quarter of fiscal 1996, just three years later, Chesapeake's production had increased sixteenfold to 17.6 Bcfe.

During fiscal 1996, Chesapeake continued its high level of drilling activity, finishing as the fourth most active driller of new wells and ranking first in average depth drilled per well (more than 16,000 feet).

By drilling deeper and utilizing today's most sophisticated technologies in developing well-known, but underexploited reservoirs, our company can reduce exploration risk and increase the potential for discovering large amounts of new oil and natural gas reserves.

COMPETITIVE ADVANTAGE No. 2

Five-year inventory of drillsites

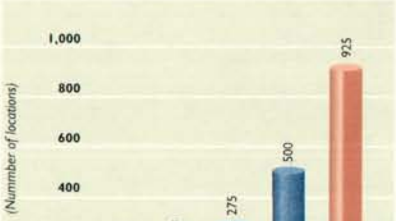
The leading indicator of any oil and natural gas producer's potential for future success is the size and quality of its inventory of future drilling projects. Chesapeake's five-year inventory of undrilled locations is our second competitive advantage and provides the springboard for our continued reserve and production growth.

For all energy producers, the greatest challenge is replacing the reserves that deplete naturally through daily oil and gas production. Similarly, the greatest challenge facing energy investors is to identify companies that can continue to grow their reserves and production while generating superior rates of return.

With over 900 undrilled locations in inventory, Chesapeake has the potential to double its oil and natural gas production and reserves.

Through Chesapeake's strategy of building a long-term inventory of future drillsites, a prospective investor is not required to speculate on how Chesapeake will replace its produced reserves. Instead, an investor only has to examine our inventory of over 900 undrilled locations to evaluate whether Chesapeake has the ability to maintain its superior growth rates.

This inventory consists of prospective drillsites in the Louisiana Austin Chalk Trend, the downdip Giddings Field in Texas, the Knox and Sholem Alechem Fields in southern Oklahoma, and our new project areas in the Arkoma Basin in eastern Oklahoma, the Lovington area in eastern New Mexico and the Williston Basin in North Dakota and Montana. Successful drilling of Chesapeake's inventory has the potential to more than double the company's proved reserves of oil and natural gas.



Undrilled Location Inventory

The common theme linking these projects is Chesapeake's exploration focus on geologically complex reservoirs, especially deep fractured carbonates. When subjected to intense geological pressure, these formations have a tendency to fracture vertically. Because of past technological limitations, fractured carbonate reservoirs have been underexploited. With the continuing evolution of horizontal drilling, 3-D seismic, and new completion techniques, Chesapeake has been able to exploit these hydrocarbon-rich formations over the past three years. We hope to make further discoveries in the future while maintaining a large backlog of drillsites.

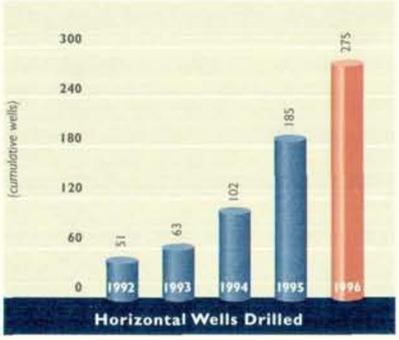
Technological leadership

COMPETITIVE ADVANTAGE Nº. 3

Scientific progress in such areas as horizontal drilling, 3-D seismic, and deep fracture stimulation have enabled Chesapeake to identify and develop new oil and natural gas reserves more profitably than at any time during the past 20 years. While distinguishing itself in each of these new technologies, Chesapeake's leadership in horizontal drilling is particularly distinctive. Our company is now the second leading driller of horizontal wells in the world, drilling 90 such wells in fiscal 1996 and 275 since 1990.

The company's expertise in horizontal drilling provides the potential for greater reserve recovery per dollar invested at an unusually low level of risk. This results in a much higher rate of return on invested capital than is typically enjoyed by the industry.

The talent of Chesapeake's exploration teams, the company's strong alliances with the vendors who design and manufacture horizontal drilling equipment, and our willingness to experiment with new ideas have allowed Chesapeake to drill increasingly deeper horizontal wells and thereby expand the boundaries of our fields. For example, in just the past two years, technical improvements in measurement-while-drilling and log-



ging-while-drilling tools, downhole motors, and drillbit technology have enabled Chesapeake to extend the industry's depth barrier from 13,000 feet to almost 17,000 feet. This provides a much larger fairway of potentially productive acreage for the company to develop.

The extension of this depth limit is important because as horizontal drilling technology improves, the number of prospective drillsites on Chesapeake's leasehold inventory can continue to increase. In the past year alone, the company added over 400 drillsites to its inventory as a result of deeper drilling successes and an aggressive leasehold acquisition program in the Louisiana Austin Chalk Trend. This area, considered uneconomical just two years ago, is today one of the most active exploration areas in the U.S.

Chesapeake also has increased its expertise by applying another significant industry advancement, 3-D seismic imaging. Advancements in computer processing capability have enabled exploration companies to enhance their understanding of deep geological structures. When applied in the appropriate geological environment, this technology results in higher success rates and more prolific wells.

During fiscal 1996, Chesapeake acquired or participated in eight 3-D seismic projects in four states. As a result of early drilling success on our 3-D seismic projects in the Knox, Lovington, and Williston Basin areas, we have planned an additional twelve 3-D projects in six states in fiscal 1997. We believe 3-D seismic surveys will play an increasingly important role in our future exploration projects.

Chesapeake's focus on exploring for underdeveloped reservoirs using advanced technologies provides considerable upside at relatively low risk.

Superior profit margin

COMPETITIVE ADVANTAGE No. 4

Chesapeake's fourth competitive advantage is our high profit margin per-unit-of-production. During fiscal 1996, this margin was $0.77 per Mcfe, the highest in our peer group. This margin is defined as oil and natural gas revenues minus lease operating costs (which include lease operating expenses and production taxes), general and administrative expenses, and oil and gas depreciation, depletion, and amortization expenses. We believe the key to creating shareholder value is generating large amounts of cash flow from Chesapeake's superior profit margin and then reinvesting this cash flow into the profitable search for new reserves.

Chesapeake's low-cost operating structure and drilling efficiencies generate the highest profit margins in the company's peer group.

We have developed our company's low cost structure by:

- Utilizing advanced drilling and completion technologies to reduce the cost of finding and producing the company's oil and natural gas reserves;
- Concentrating the company's drilling in areas which provide the critical mass necessary to spread operating and overhead costs over a large number of wells;
- Operating 87% of the company's production, thereby allowing our employees to implement the most cost-effective and technologically sophisticated drilling, completing, and operating procedures; and
- Maintaining a flat organizational structure with performance-based pay and stock option incentives to motivate Chesapeake's employees so they can quickly respond to attractive opportunities.

Although we believe continuing worldwide economic growth may cause oil and gas prices to increase, Chesapeake budgets for inflation-adjusted prices to remain flat in the coming years. Therefore, management believes the most profitable Mcf of gas or barrel of oil that can be produced is the one produced today.

Long-lived reserves, which are burdened by future operating, financing, and administrative costs and are adversely effected by the time value of money and the risk of future mechanical problems, are less valuable than reserves that can be monetized more quickly. Consequently, reserves produced in a shorter time frame have higher profit margins and therefore are more likely to create shareholder value than longer-lived reserves.

Chesapeake attempts to develop large per-well oil and natural gas reserves with an average life of five to seven years, intentionally shorter than the industry average of eight to ten years. The combination of accelerating the production of reserves, generating high cash flows from the production, and then successfully reinvesting the cash flows into a technologically advanced exploration program is the formula that we believe can provide Chesapeake's shareholders with increasing value.

COMPETITIVE ADVANTAGE Nº. 5

Management's large equity stake

Chesapeake's fifth competitive advantage is management and directors' ownership of approximately 42% of Chesapeake's equity, among the highest in the industry and of all NYSE-listed companies. This large ownership stake has fostered a culture of entrepreneurship in our company that we believe results in more creative and productive employees. Furthermore, it more closely aligns the interests of management and shareholders.

The daily decisions involved in managing Chesapeake's active and technically sophisticated drilling program are made decisively and are implemented by employees who have direct lines of communication to management and a significant stake in the outcome of those decisions. This flat organizational structure combined with our motivated work teams enables Chesapeake to seize competitive opportunities more quickly and to establish leasehold dominance in its areas of operations.

Looking Forward

Chesapeake's growth strategy has always been based on three fundamental beliefs:

- Greater financial returns and more shareholder value can be created by drilling new wells;
- Large amounts of oil and natural gas reserves remain in fractured carbonate reservoirs; and
- Continuing advances in technology will enable Chesapeake to more profitably extract its existing reserves and to more easily develop significant new reserves.

During the past seven years, we have grown from five employees and $50,000 in assets to an industry leader with 275 employees and an enterprise value of almost $2 billion. We believe Chesapeake is evolving into one of the premier large capitalization independent energy producers.

Management and directors' 42% equity stake in Chesapeake, one of the highest of NYSE companies, creates an alignment of management and shareholder interests.

To accelerate this evolution, we are committed to increasing the financial strength of our company so that we can more reliably replicate our results over the long term. Our success in fiscal 1996 provides the foundation for our optimism that Chesapeake will continue to remain an industry leader in creating shareholder value.

Aubrey K. McClendon
Chairman and CEO

Tom L. Ward
President and COO
October 1, 1996

Large amounts

of oil and gas

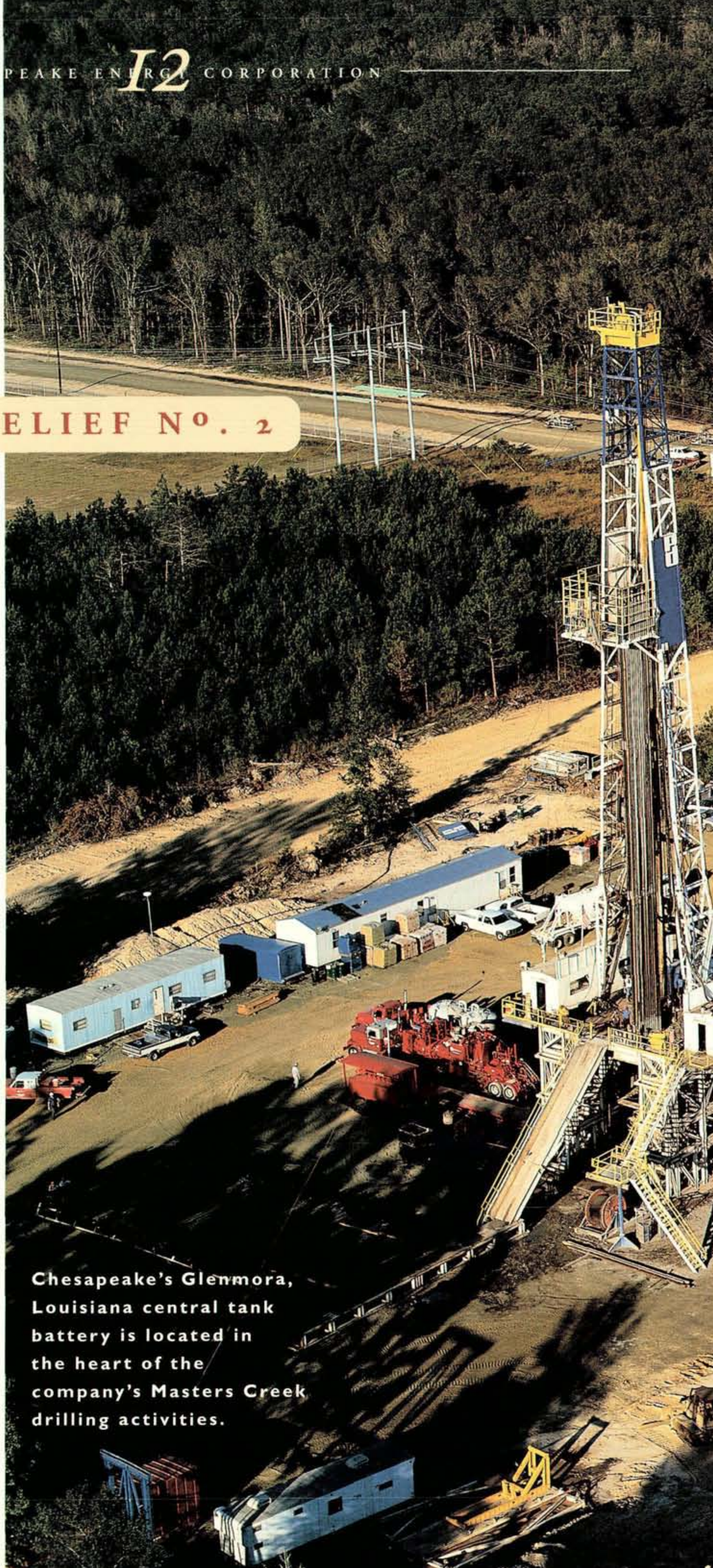
FUNDAMENTAL BELIEF Nº. 2

can be found

in fractured

carbonate

reservoirs.



Chesapeake's Glenmora, Louisiana central tank battery is located in the heart of the company's Masters Creek drilling activities.

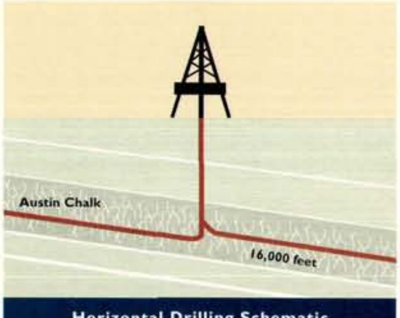
FOCUSING ON fractured carbonate reservoirs where advanced drilling

CHESAPEAKE'S AREAS OF OPERATION

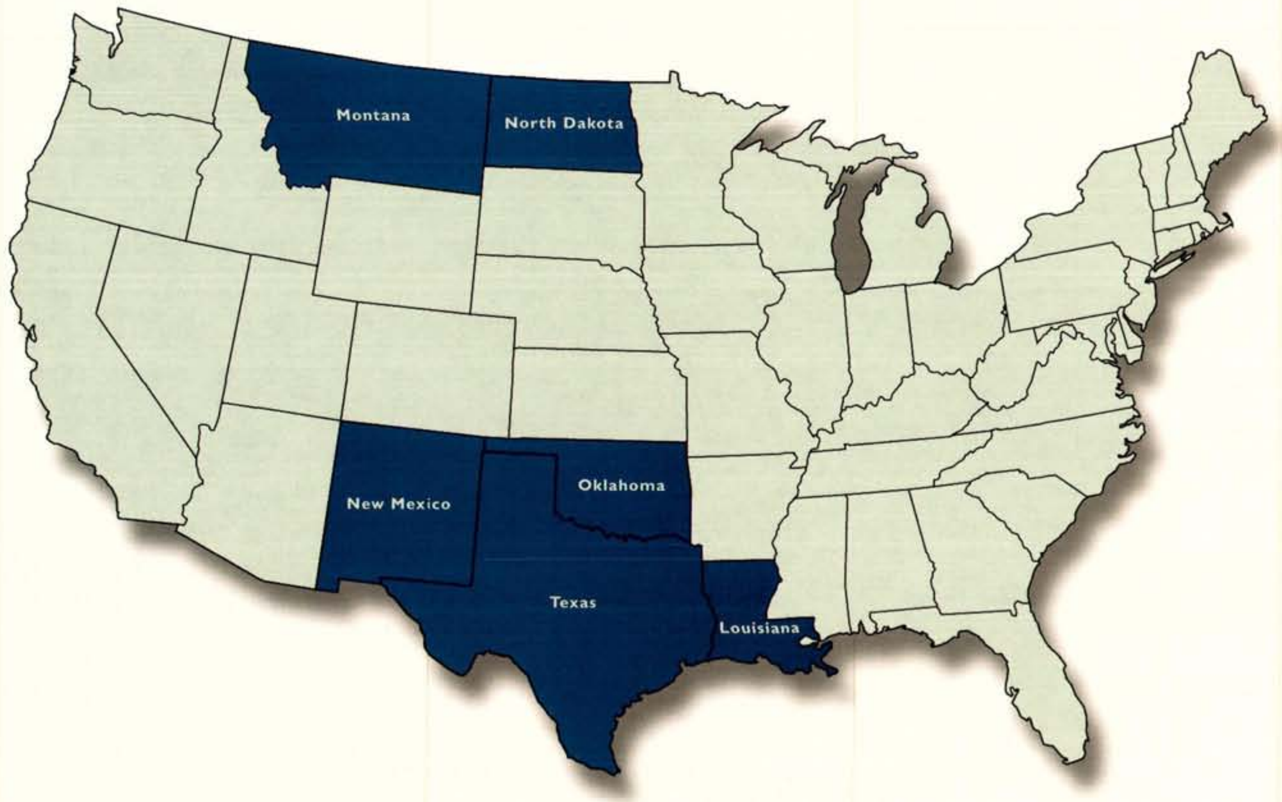
technologies provide a competitive advantage, Chesapeake's drilling activities are diversified over a number of geographical areas and geological formations. This reduces risk and leverages our operating talents into major producing onshore areas in the U.S. In these areas, Chesapeake utilizes horizontal drilling, 3-D seismic, and deep fracture stimulation technologies to reduce risk and enhance reserve recoveries.

Horizontal drilling technology has evolved rapidly during Chesapeake's three year history as a public company.

With continuing technological improvements, Chesapeake can now drill horizontal wells to 16,000', providing increased exploration opportunities.



Horizontal Drilling Schematic



Chesapeake's drilling activities are concentrated in major onshore producing areas where the company is utilizing its drilling expertise to develop underexploited formations.

IN ADDITION to the company's primary areas of operation,

PRIMARY OPERATING AREAS

Chesapeake's exploration teams continue to search for projects where the company can leverage its proven exploration expertise into new areas.

Chesapeake's three primary operating areas are the Giddings Field in Texas; the Louisiana Austin Chalk Trend; and the Knox, Sholem Alechem, and Golden Trend Fields of southern Oklahoma.

Giddings Field

Chesapeake's most significant producing assets are located in the Giddings Field, one of the most active fields in the United States. The primary producing zone in the Giddings Field is the Austin Chalk formation, a fractured carbonate reservoir found at depths ranging from 5,000 feet to 18,000 feet along a 15,000 square mile trend across Texas and Louisiana.

The Austin Chalk is a complex geological formation which holds large volumes of oil and natural gas within a series of naturally occurring vertical fractures. As a result, traditional vertical drilling technology has been largely uneconomical in developing this reservoir because it typically intersected only one of these fractures. However, with the advent of horizontal drilling, Chesapeake and a limited number of other companies have been able to unlock these prolific, but previously underdeveloped, Austin Chalk reserves.

Further separating Chesapeake from its competitors in this field has been the company's concentration of its Giddings drilling efforts in the gas-prone downdip area of the field. In this area, the Austin Chalk is deposited at depths below 11,000 feet. Chesapeake's engineers believe Giddings is one of the largest discoveries of onshore gas in the United States in recent years.

Giddings Field	
Drilled Wells	175
Undrilled Locations	75-125

Chesapeake's success in this area is attributable to four major factors:

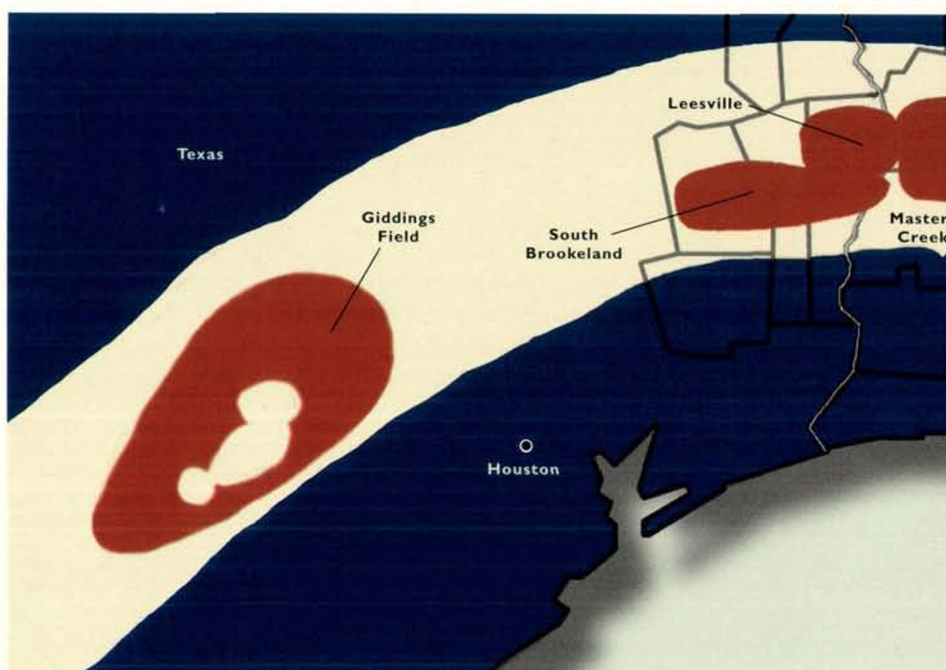
- The limited reservoir drainage that has occurred as a result of the small number of vertical wells previously drilled in the downdip area;
- Chesapeake's aggressive leasehold acquisition program, which has permitted the company to create larger spacing units and thereby reduce competition for reserves from offsetting wells;
- The continued technological advances in horizontal drilling, which have significantly lowered development costs, expanded the field's boundaries into deeper areas, and increased per-well productivity through the ability to drill longer distances within a more tightly defined target zone; and
- The geological setting of the downdip Austin Chalk, which is characterized by greater reservoir pressure and more intensive fracturing than updip areas.

As a result of these factors and the experience developed by our company after drilling 275 horizontal wells, Chesapeake's downdip wells have produced greater per-well reserves and depleted more slowly than average wells in other areas of Austin Chalk production.

After drilling more than 175 wells in the downdip Giddings during the past three years, Chesapeake plans to drill approximately 25 net wells in this area in fiscal 1997. The company will also continue its search for other productive formations and for the geological limits of the Austin Chalk in the downdip Giddings area.

PRIMARY OPERATING AREAS

Louisiana Austin Chalk Trend

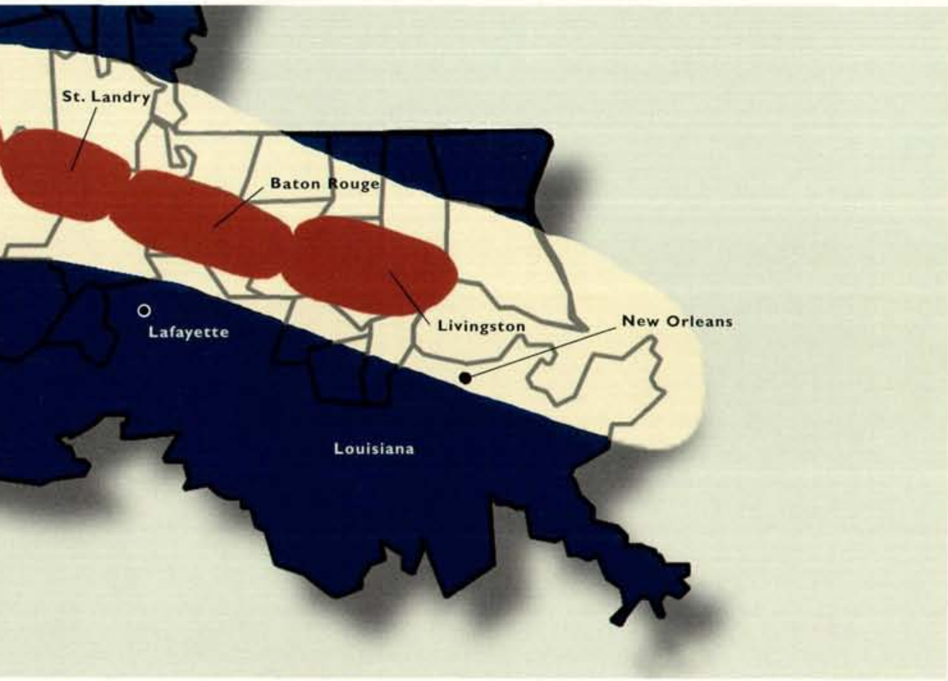


The Louisiana Trend is the newest of Chesapeake's three primary operating areas and will be central to the company's exploration and development activities for the foreseeable future. In late 1994, Occidental Petroleum Corporation announced the completion of a horizontal Austin Chalk well in central Louisiana. This well, a rank wildcat drilled more than 200 miles east of the downdip Giddings area, alerted the industry to the Masters Creek area as a location of potentially large Austin Chalk reserves.

The success of Occidental's well and the information provided by over 225 penetrations of the Austin Chalk in Louisiana by older vertical wells confirmed Chesapeake's geological and engineering hypothesis: significant quantities of oil and natural gas reserves could be economically extracted from deep horizontal wells in the Louisiana Austin Chalk Trend.

Because of our advanced geological understanding of the Austin Chalk and our entrepreneurial culture, Chesapeake moved more quickly than its competitors to accumulate high quality acreage within this trend. Now, some 18 months later, Chesapeake is the leading leasehold owner in the Louisiana Trend with over one million acres. The company's early entry and aggressive acquisition program enabled our land department to acquire the Louisiana Trend acreage at an average cost of only $125 per acre, less than 20% of its estimated replacement cost.

Chesapeake's rapid response to the opportunity presented by the discovery of significant quantities of oil and natural gas in the Louisiana Austin Chalk has provided the company



Louisiana Austin Chalk Trend	
Drilled Wells	15
Undrilled Locations	up to 500

with up to 500 undrilled locations in what has quickly become one of the most active onshore exploration plays in the U.S. in several decades.

Chesapeake's drilling results from its initial round of wells in the Masters Creek portion of the Louisiana Trend have been encouraging. As a result, the company is increasing its drilling activity in this area from five wells started in fiscal 1996 to 25-35 wells planned for fiscal 1997. Increasing production from this area should be the driver that provides the opportunity for the company to double its production during the next two years.

During fiscal 1997, Chesapeake plans to test and begin developing each of its six prospect areas in the Louisiana Trend: South Brookeland, Leesville, Masters Creek, St. Landry, Baton Rouge and Livingston. In conjunction with its Austin Chalk drilling, Chesapeake will also begin testing its geological theory that the deeper and more prolific Tuscaloosa formation underlying the Baton Rouge portion of our Louisiana Trend acreage may be productive.

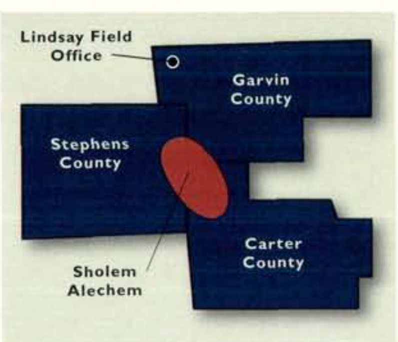
In addition, Chesapeake is participating in several gas infrastructure expansion projects that should result in higher wellhead pricing for the company's production in the Louisiana Trend. These projects include a 15% ownership in a gas processing plant and a 50% ownership in the Louisiana Chalk Gathering System, a 350 million cubic feet of gas per day system designed for the Masters Creek and St. Landry areas.

PRIMARY OPERATING AREAS

Southern Oklahoma

Knox	
Drilled Wells	41
Undrilled Locations	150-250

Sholem Alechem	
Drilled Wells	25
Undrilled Locations	25-75



During the past three years, Chesapeake has also developed two important new projects in Oklahoma, Knox and Sholem Alechem. In Knox, Chesapeake was the first company to establish commingled production from the Sycamore, Woodford, Hunton, and Viola fractured carbonates below 15,000 feet. As a result of this drilling success, an aggressive leasehold acquisition program, and the purchase of Amerada Hess' working interest in Chesapeake's wells, the company believes it can dominate the future development of what has become the most active field in the Mid-Continent region.

Through fiscal 1996, Chesapeake successfully completed 41 Knox wells and was drilling or completing seven additional wells. Chesapeake's acreage inventory of 65,000 gross acres in the Knox area could support the drilling of approximately 150-250 additional wells.

Elsewhere in southern Oklahoma, Chesapeake has enjoyed considerable success in the Sholem Alechem portion of southern Oklahoma's giant Sho-Vel-Tum field. Since its discovery more than 80 years ago, this field has produced more than one billion barrels of oil and one trillion cubic feet of natural gas. Chesapeake initiated its Sholem Alechem project on the belief that the area's geological environment would be conducive to the application of the company's expertise with horizontal drilling technology.

Chesapeake believes its results help prove the company's theory that by the innovative application of horizontal drilling and 3-D seismic technologies, significant new reserves of oil and gas can be developed, even in fields once considered fully explored.

Through fiscal 1996, the company had drilled 25 successful horizontal wells in Sholem Alechem and believes its acreage inventory could support the drilling of an additional 25-75 wells.

SECONDARY OPERATING AREAS

Williston Basin

Williston Basin	
Drilled Wells	1
Undrilled Locations	75-150

The Williston Basin in North Dakota and Montana is another example of Chesapeake's ability to develop large projects in areas with hydrocarbon reservoirs that may respond well to horizontal drilling or 3-D seismic technology. The focus of the company's 325,000 acres in the southern portion of the basin is the Red River "B" formation, where Chesapeake's competitors have drilled more than 75 horizontal oil wells and where Chesapeake plans to drill 5-10 wells in fiscal 1997.

On 125,000 acres in the northern portion of the basin, Chesapeake is using 3-D seismic to target Red River "C" and "D" vertical prospects. The company's first well in this area is now underway and more seismic and drilling work is scheduled for fiscal 1997.

Lovington

Lovington	
Drilled Wells	1
Undrilled Locations	50-75

In the Lovington Project in Lea County, New Mexico, Chesapeake is utilizing 3-D seismic technology to search for algal mound buildups. The company believes these reservoirs have been overlooked in this portion of the Permian Basin because of inconclusive results provided by traditional 2-D seismic imaging technology.

During fiscal 1996, Chesapeake shot two 3-D seismic surveys in this oil-prone area. These surveys have identified more than 50 geological prospects that are attractive to the company's geoscientists. After an aggressive land acquisition campaign and initial drilling success in fiscal 1996, Chesapeake plans to significantly expand its drilling and seismic activities in the Lovington area in fiscal 1997.

Arkoma Basin

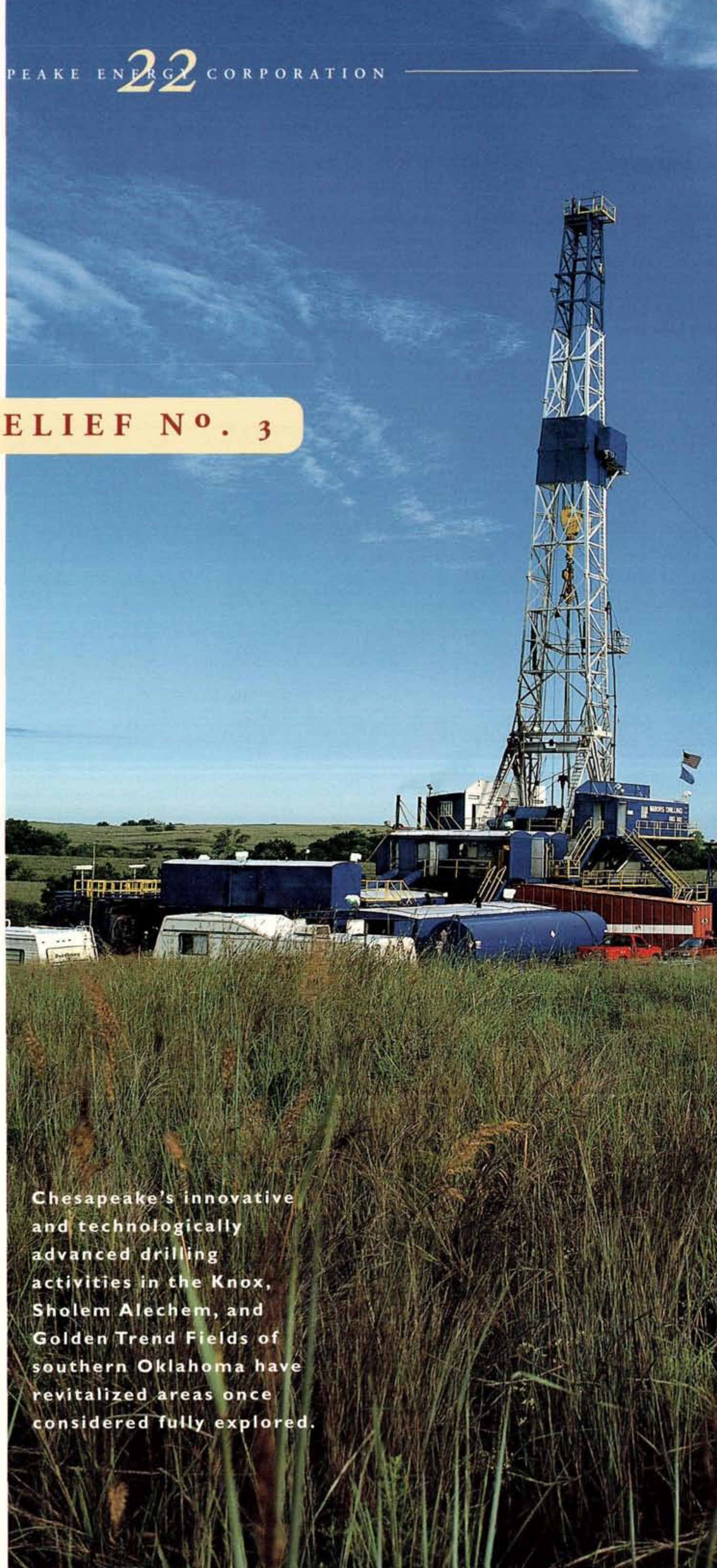
Arkoma Basin	
Drilled Wells	15
Undrilled Locations	75

Chesapeake has initiated a seismic and leasehold acquisition program in the geologically complex and lightly-explored southern portion of the Arkoma Basin in southeastern Oklahoma.

The company has developed Jackfork and Spiro prospects in the Arkoma on the belief that recent developments in 3-D seismic technology and in drilling and completion techniques can provide attractive drilling opportunities. Chesapeake's Arkoma prospects target gas reserves from multiple payzones at depths from 4,000 to 16,000 feet. Through fiscal 1996, the company had drilled 15 Arkoma wells. Chesapeake plans to drill 4-5 wells in fiscal 1997 and is evaluating several 3-D seismic opportunities that could increase our drilling efforts in this area.

Technology is the key to reducing risk and increasing returns.

FUNDAMENTAL BELIEF No. 3



Chesapeake's innovative and technologically advanced drilling activities in the Knox, Sholem Alechem, and Golden Trend Fields of southern Oklahoma have revitalized areas once considered fully explored.

Board of Directors

CORPORATE BIOGRAPHIES


Aubrey K. McClendon

Chairman of the Board, Chief Executive Officer and Director

Aubrey K. McClendon has served as Chairman of the Board and Chief Executive Officer and has been a director of the company since its inception. From 1982 to 1989, Mr. McClendon was an independent producer of oil and gas. Mr. McClendon has conducted oil and gas operations with Tom L. Ward through affiliated entities since 1983. 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 graduated from Duke University in 1981.

President, Chief Operating Officer and Director

Tom L. Ward has served as President and Chief Operating Officer and has been a director of the company since its inception. From 1982 to 1989, Mr. Ward was an independent producer of oil and gas. Mr. Ward has conducted oil and gas operations with Mr. McClendon through affiliated entities since 1983. Mr. Ward graduated from the University of Oklahoma in 1981.


Tom L. Ward


E. F. Heizer, Jr.

Director

E. F. Heizer, Jr. has served as a director of the company since February 1993. He founded Heizer Corp. in 1969 and served as Chairman and Chief Executive Officer until 1986, when Heizer Corp. was reorganized into a number of public and private companies. Mr. Heizer was assistant treasurer of the Allstate Insurance Company from 1962 to 1969. He was employed by Booz, Allen and Hamilton from 1958 to 1962, Kidder, Peabody & Co. from 1956 to 1958 and Arthur Anderson & Co. from 1954 to 1956. He is chairman of the Heizer Center for Entrepreneurship at the Kellogg School of Management at Northwestern University and the Executive Committee of Yale Law School. Mr. Heizer graduated from Northwestern University in 1951 and received a Juris Doctorate from Yale in 1954.

Director

Breene M. Kerr has served as a director of the company since February 1993. In 1969, Mr. Kerr founded Kerr Consolidated, Inc., of which he is currently Chairman and President, and co-founded the Resource Analysis and Management Group. From 1967 to 1969, he was Vice President of Kerr-McGee Chemical Corporation and served as a director of Kerr-McGee Corporation from 1957 to 1981. Mr. Kerr has served as a chairman of the Investment Committee for the Massachusetts Institute of Technology and is a life member on the Board of Trustees. Mr. Kerr 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., located in Oklahoma City. Mr. Kerr graduated from the Massachusetts Institute of Technology in 1951.

Breene M. Kerr

Director

Shannon T. Self has served as a director of the company since February 1993. Mr. Self 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. He graduated from the University of Oklahoma in 1979 and received a Juris Doctorate from Northwestern University in 1984.

Shannon T. Self

Director

Frederick B. Whittemore has served as a director of the company since February 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 was a partner with Morgan Stanley & Co. from 1967 to 1970 and an associate from 1958 to 1967. He is a director of Integon Corporation, an insurance company listed on the New York Stock Exchange, and Southern Pacific Petroleum Corporation, an Australian oil and gas company. Mr. Whittemore graduated from Dartmouth College in 1953 and from Dartmouth's Amos Tuck School of Business Administration in 1954.

Frederick B. Whittemore

Director

Walter C. Wilson has served as a director of the company since February 1993. From 1963 to 1974 and from 1978 to the present, Mr. Wilson has been 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, a satellite remote sensing company in Rockville, Maryland, and National Compensation Plans, Inc. Mr. Wilson graduated from Dartmouth College in 1958.

Walter C. Wilson

Officers and Employees

CHESAPEAKE'S EMPLOYEES

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

Tom L. Ward
President and Chief Operating Officer

Marcus C. Rowland
Vice President -Finance and Chief Financial Officer

Steven C. Dixon
Senior Vice President - Operations

J. Mark Lester
Senior Vice President - Exploration

Henry J. Hood
Vice President - Land and Legal

Ronald A. Lefaive
Controller and Chief Accounting Officer

Martha A. Burger
Treasurer and Human Resources Manager

Thomas S. Price, Jr.
Vice President - Corporate Development

Tony S. Say
Vice President - Marketing

Joel Alberts
Geologist
Richey Albright
Foreman
Sandra Alvarado
Lease Records Supervisor
Eduardo Alvarez-Salazar
Roustabout
Heather Anderson
Lease Records
Colley Andrews
District Manager - Oklahoma
Judy Arias
Accounting
Paula Asher
Drilling Secretary
Eric Ashmore
Drilling Supervisor
Jack Austin
Geologist
Barbara Bale
Regulatory Analyst
Marilyn Ball
JIB Coordinator
Ralph Ball
Network Coordinator
Marsha Barnes
Division Order Analyst
Stacy Bateman
Division Order Assistant
Rodney Beverly
Production Foreman
Randy Borlaug
Purchasing
Rene Brignac
Accounting

James Brinkley
Roustabout
Carla Brittain-Reed
Geology Technician
Laurie Brown
Accounting
Pamela Brown
Title Analyst
Keri Bruegger
Administrative Assistant
Martha Burger
Treasurer/Human Resources Manager
Jeff Burling
Geologist
Patricia Busby
Operations Accountant
Shelli Butler
Accounting
Patti Carlisle
Executive Assistant
Leonardo Carmona
Roustabout
Ramon Carmona
Roustabout
Martin Carmona-Cruz
Roustabout
John Carsrud
Drilling Superintendent
Ilan Cathey
Geology Technician
David Chesher, Jr.
Landman
Dale Clark
Drilling Engineer
Kimberly Coffman
Operations Accounting Supervisor

John Colbert
Drilling Engineer
Michael Coles
Pumper
Gary Collings
Division Order Analyst
Mike Collis
Production Foreman
Maria Constantino
Accounting
Dale Cook, Jr.
Operations Accounting Supervisor
Rose-Marie Coulter
Lease Draft Analyst
Marie Cox
Accounting
Danna Darragh
Gas Contracts
Ken Davidson
Drilling Superintendent
Ted Davis
Pumper
Kevin Decker
Oil Revenue Coordinator
George Denny
Landman
Tim Denny
Administrative Services
David DeSalvo
Production Foreman
Alton Dickey
Pumper
Steve Dixon
Senior Vice President-Operations

Janice Dobbs
Compliance Manager
Mandy Duane
Title Assistant
Gary Dunlap
Land Manager - Louisiana
Julie Eck
Assistant Treasurer
Vicki Ervin
Accounting
Kyle Essmiller
Financial Accounting Coordinator
Jan Fair
Records Assistant
Karla Fairchild
Lease Records Assistant
Amy Fell
Production Technician
David Ferguson
Landman
Teresa Fife
Operations Accountant
Ursula Fletcher
Secretary
Vanessa Ford
Division Order Assistant
Pat Foster
Geology Technician
Rick Foster
Geology Technician
Barbara Frailey
Land Assistant
Jason Francis
Operations Accountant

Sheree Franks
Accounting Coordinator
Ed Gallegos
Production Engineer
Linda Gardner
Executive Assistant
Steve Gaskins
Pumper
Celia Gibson
Gas Revenue Coordinator
Charlene Glover
Landman
Randy Goben
Accounting Manager
Ron Goff
Drilling Engineer
Jim Gomez
Administrative Services
Leslie Gomez
Receptionist
Traci Gonzales
Tax Supervisor
Pat Goode
Land Manager - Oklahoma
Janet Gresham
Gas Revenue Supervisor
Jennifer Grigsby
Accounting Coordinator
Brian Gross
Production Engineer
Brian Guire
Programmer
Cheryl Hamilton
Accounting Coordinator

Cliff Hanoch
Geophysicist
Tina Harmon
Gas Marketing Representative
Kathy Harrell
Land Technician
Gayle Harris
Division Order Supervisor
Jim Harrison
Drilling Superintendent
Gaylon Havel
Field Representative
Julie Hays
Land Assistant
Mike Hazlip
Landman
Duane Heckelsberg
Geologist
Robert Hefner, IV
Geologist
Steve Henley
Production Superintendent
Tim Herrington
Roustabout
David Higgins
Production Foreman
Kristi Hitz
Receptionist
Carol Holden
Division Order Supervisor
Larry Holladay
Drilling Superintendent
Henry Hood
Vice President - Land and Legal

Kenneth Hopkins
Production Facility Operator
Tiffany Horsley
Receptionist
Jan Horton
Landman
Jan Howard
Accounting
David Hudnall
Production Facility Operator
Pamala Huggins
Engineering Technician
Richard Hughes
Production Foreman
Brian Imes
Administrative Services
Charles Imes
MIS Director
Kimberly Imes
Lease Records
Lorrie Jacobs
Human Resources Administrator
Douglas Johnson
Geologist
Jim Johnson
Gas Contracts Manager
Michael Johnson
Assistant Controller
Rusty Johnson
Roustabout
Christy Johnston
Treasury Analyst
Mike Johnston
Pumper

Frank Jordan
District Manager - Texas
Mitchell Kennedy
Welder
Phyllis Kimray
Land Technician
Darvin Knapp
Drilling Superintendent
Greg Knight
Engineering Technician
Ted Krigbaum
Landman
Wesley Kruckenberg
Production Foreman
Steve Lane
Geologist
Jesse Langford
Landman
Barry Langham
Operations Engineer
Cindy LeBlanc
Land Assistant
Dan LeDonne
Administrative Services Supervisor
Ron Lefaive
Controller and Chief Accounting Officer
Mark Lester
Senior Vice President- Exploration
Kirsten Lewellen
Accounting Coordinator
Kimberly Louthan
Lease Analyst
Kinney Louthan
Landman

Heath Lovinggood
Accounting Auditor
Janet Lowery
Division Order Analyst
Larry Lunardi
Geophysicist
Marilyn Lynch
Title Analyst Supervisor
Troy Mahan
Pumper
Felipe Maldonado
Roustabout
Liz Mallett
Executive Assistant
Tim Marnich
Production Facility Operator
John Marks
Programmer
Sandra Mathis
Executive Assistant
Rich McClanahan
Production Engineer
Aubrey McClendon
Chairman & CEO
Joe McClendon
Special Projects
Janelle McNeely
Title Supervisor
Carrol McCoy
Lease Analyst
Frank McGee
Roustabout
Shannon McKanna
Receptionist
Scott McMurran
Audit Supervisor

Sondra McNeiland
Engineering Technician
Debi Meyer
Geophysical Technician
Steve Miller
Vice President - Drilling
Chester Milligan
Gas Marketing Representative
Laura Minter
Lease Records
Dennis Moore
Drilling Engineer
Kenny Moreau
Drilling Engineer
Tommy Morphew
Pumper
Leland Murray
Pumper
Elizabeth Muskrat
Title Analyst
Tara Nash
Lease Records Assistant
Mickey Nemecek
Lease Analyst
Catherine Otey
Treasury Assistant
Alan Page
Gas Revenue Accountant
Greg Pearce
Field Representative
Michelle Peery
Payroll Assistant
Linda Peterburs
Accounting Coordinator

CHESAPEAKE'S EMPLOYEES

Dale Petty
Accounting Coordinator
Randy Pierce
Purchasing Manager
Pat Pope
Oil Revenue Supervisor
Bobby Portillo
Roustabout
Fernando Portillo
Pumper
Robert Potts
Geology Technician
Robert Powell, Jr.
Production Facility Operator
Carlin Price
Title Analyst
Tom Price, Jr.
VP - Corporate Development
Wayne Psencik
District Manager - Louisiana
John Qualls
Pumper
Jimmy Randol
Roustabout
Lori Ray
Land Technician
Aaron Reyna
Engineer
Jackie Rhoads
Administrative Assistant
Deborah Richardson
Executive Assistant
Mark Richeson
Production Engineer

Christie Rickey
Gas Revenue Assistant
Tammy Rideau
Receptionist
Bryan Robichaux
Production Facility Operator
Mark Robins
Audit Coordinator
Connie Robles
Property Administration Manager
Randy Rodrigue
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Lawrence Rogers
Production Foreman
Pat Rolla
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David Rose
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Janna Rothwell
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Vice President - Finance and CFO
Danny Rutledge
Pumper
Bryan Sagebiel
Geology/MIS Coordinator
Darnell Savoy
Drilling Technician
Chris Saxon
Geology Technician
Tony Say
Vice President - Marketing

Hank Scheel
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Lease Records Supervisor
Charles Scholz
Pumper
Bonnie Schomp
Landman
Kurt Schrantz
Geophysicist
Ricky Scruggs
Roustabout
Cheryl Self
Land Technician
Stephanie Shedden
Lease Records Assistant
Arlene Shuman
Lease Analyst
Charles Smith
Attorney
Vivian Smith
Executive Assistant
Jan Solinski
Division Order Analyst
Charles Sonnier
Production Facility Operator
Kevin Soter
Production Engineer
Antonio Soto
Roustabout
Larry Stephens
Geologist
Donna Stewart
Contracts Administrator
Stan Stinnett
Pumper

Brenda Stremble
Lease Analyst
John Striplin
Field Representative
Heather Sullivan
Lease Records
Randy Summers
Production Superintendent
Wesley Tayrien
Pumper
Mike Thompson
Pumper
Steve Tipton
Drilling Engineer
Bill Totty
Gas Marketing Coordinator
Ken Turner
Drilling Superintendent
Amy VanBrunt
Accounting Coordinator
Joe Vaughan
Landman
Melissa Verett
Tax Accountant
Cassandra Vesta
Investor Relations Assistant
Laura Viau
Production Assistant
Peggy Vosika
Lease Analyst
Elizabeth Voss
Gas Contracts Administrator
Conway Waak, Jr.
Drilling Engineer

Tommy Wade
Roustabout
William Wagner
Division Order Analyst
Charles Waldroup
Roustabout
Ronnie Ward
Land Manager - Texas, New Mexico, and Williston Basin
Tom Ward
President and COO
Julie Washam
Investor Relations
Patsy Watters
Division Order Analyst
Clarence Watts
Production Foreman
Linda Wayland
Land Technician
Melanie Weaver
Title Analyst
Keith Weekly
Production Facility Operator
Janet Weeks
Engineering Technician
Greg Weinschenk
Pumper
Lu Ann Wernli
Safety Administrator
Colene Whitaker
Land Technician
Shelly White
Land Technician
Tim Wiemers
Production Engineer

Joan Wilber
Lease Analyst
Angela Wiley-Lair
Land Assistant
Ken Will
Drilling Superintendent
Cindi Williams
Engineering Technician
Ranae Williams
Accounting
Jeff Williams
Landman
Thomas Williams
Drilling Engineer
Brian Winter
Geologist
David Wittman
Production Supervisor
Jimmy Wright
Production Foreman
Lorre Youngblood
Land Technician
Gerald Zgabay
Pumper
Karen Zinn
Oil Revenue Accountant

CHESAPEAKE Financial Section

1996 FINANCIALS TABLE OF CONTENTS

SELECTED FINANCIAL DATA

Year Ended June 30,	1996	1995	1994	1993	1992
Revenues:		($ in thousands, except per share data)			
Oil and gas sales	$ 110,849	$ 56,983	$ 22,404	$ 11,602	$ 10,520
Gas marketing sales	28,428	–	–	–	–
Oil and gas service operations	6,314	8,836	6,439	5,526	7,656
Interest and other	3,831	1,524	981	880	542
Total revenues	149,422	67,343	29,824	18,008	18,718
Costs and expenses:					
Production expenses and taxes	8,303	4,256	3,647	2,890	2,103
Gas marketing expenses	27,452	–	–	–	–
Oil and gas service operations	4,895	7,747	5,199	3,653	4,113
Oil and gas depreciation, depletion and amortization	50,899	25,410	8,141	4,184	2,910
Depreciation and amortization of other assets	3,157	1,765	1,871	557	974
General and administrative	4,828	3,578	3,135	4,906	3,314
Interest and other	13,679	6,627	2,676	2,282	2,577
Total costs and expenses	113,213	49,383	24,669	18,472	15,991
Income (loss) before income taxes	36,209	17,960	5,155	(464)	2,727
Income tax expense (benefit)	12,854	6,299	1,250	(99)	1,337
Net income (loss)	$ 23,355	$ 11,661	$ 3,905	$ (365)	$ 1,390
Net income (loss) per common share	$ .80	$ .42	$ .16	$ (.04)	$ .10

Cash Flow Data:					
Cash provided by (used in) operating activities	$ 120,972	$ 54,731	$ 19,423	$ (1,499)	$ 11,550
Cash used in investing activities	344,389	112,703	29,211	15,142	26,987
Cash provided by financing activities	219,520	97,282	21,162	20,802	12,779
Balance Sheet Data (at end of period):					
Total assets	$ 572,335	$ 276,693	$ 125,690	$ 78,707	$ 61,095
Long-term debt, net of current maturities	268,431	145,754	47,878	14,051	22,154
Stockholders' equity	177,767	44,975	31,260	31,432	132

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

Chesapeake's revenue, net income, operating cash flow, and production reached record levels in 1996. Increased cash flow from operations, in combination with the issuance of $120 million of 9.125% Senior Notes and the sale of approximately three million shares of common stock in April 1996, allowed the company to fund its net capital expenditures of $344 million. The company also repaid all amounts outstanding under its $125 million Revolving Credit Facility and currently has $75 million of available bank credit committed under this expanded credit facility.

During fiscal 1996, the company participated in 148 gross wells (69.0 net), of which 111 were operated by the company. The company's proved reserves increased by 183 Bcfe to 425 Bcfe as a result of this drilling and the purchase of proved reserves from Amerada Hess Corporation compared to 60.2 Bcfe of production, resulting in reserve replacement in excess of 300% compared to production.

The company's business strategy has continued to emphasize the acquisition of large prospective leasehold positions to provide a multi-year inventory of drilling locations. By June 1996, the company had increased its acreage position to approximately 200,000 gross acres of developed leasehold and approximately 2 million gross acres of undeveloped leasehold. During 1996, the company continued the expansion of its exploration focus in the Louisiana Austin Chalk Trend and began a significant acreage acquisition program in the Williston Basin. The company also conducted or participated in 3-D seismic programs in the Lovington area, the Giddings Field, the Knox Field and in the Williston and Arkoma Basin areas to evaluate the company's acreage inventory.

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

Year Ended June 30,	1996	1995	1994
Net Production Data:			
Oil (MBbl)	1,413	1,139	537
Gas (MMcf)	51,710	25,114	6,927
Gas equivalent (MMcfe)	60,190	31,947	10,152
Oil and Gas Sales ($ in 000's):			
Oil	$ 25,224	$ 19,784	$ 8,111
Gas	85,625	37,199	14,293
Total oil and gas sales	$ 110,849	$ 56,983	$ 22,404
Average Sales Price:			
Oil ($ per Bbl)	$ 17.85	$ 17.36	$ 15.09
Gas ($ per Mcf)	$ 1.66	$ 1.48	$ 2.06
Gas equivalent ($ per Mcfe)	$ 1.84	$ 1.78	$ 2.21
Oil and Gas Costs ($ per Mcfe):			
Production expenses and taxes	$ .14	$ .13	$ .36
General and administrative	$ .08	$ .11	$ .31
Depreciation, depletion and amortization	$ .85	$ .80	$ .80
Net Wells Drilled:			
Horizontal wells	42.0	28.5	11.1
Vertical wells	27.0	23.0	7.9
Net Wells at End of Period	186.2	91.2	57.9

RESULTS OF OPERATIONS

For the fiscal year ended June 30, 1996, the company realized net income of $23.4 million, or $0.80 per common share, on total revenues of $149.4 million. This compares to net income of $11.7 million, or $0.42 per common share, on total revenues of $67.3 million in 1995, and net income of $3.9 million, or $0.16 per common share, on total revenues of $29.8 million in fiscal 1994. The significantly higher earnings in 1996 as compared to 1995 and 1994 were largely the result of higher production and prices per Mcfe, partially offset by higher oil and gas depreciation, depletion and amortization and higher interest costs.

Oil and Gas Sales

During fiscal 1996, oil and gas sales increased 94% to $110.8 million versus $57.0 million for fiscal 1995 and 395% from the fiscal 1994 amount of $22.4 million. The increase in oil and gas sales resulted primarily from strong growth in production volumes. For fiscal 1996, the company produced 60.2 Bcfe, at a weighted average price of $1.84 per Mcfe, compared to 31.9 Bcfe produced in fiscal 1995 at a weighted average price of $1.78 per Mcfe, and 10.2 Bcfe produced in fiscal 1994 at a weighted average price of $2.21 per Mcfe. This represents production growth of 89% for fiscal 1996 compared to 1995 and 490% compared to 1994.

These increases in production volumes reflect the company's successful exploration and development program. The table below shows the company's production by major field area for fiscal 1996 and fiscal 1995.

The company's gas production represented approximately 86% of the company's total production volume on an equivalent basis in fiscal 1996. This is compared to 79% in fiscal 1995 and 68% in 1994. This is a result of the company's drilling in deeper, more gas-prone areas of the Giddings and Knox Fields.

For fiscal 1996, the company realized an average price per barrel of oil of $17.85, compared to $17.36 in fiscal 1995 and $15.09 in fiscal 1994. 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. In fiscal 1996, the company realized $0.9 million less in oil revenues than it would have received from unhedged market prices.

Gas price realizations increased from fiscal 1995 to 1996 by approximately 12%, despite lower gas revenue realized by the company during the fourth fiscal quarter of 1996 as a result of the hedging activity. As a result of hedging, the company had gas revenues during that period that were approximately $5.1 million less than unhedged market prices. Although gas prices generally increased during 1996, the weighted average realization per Mcf in 1996 was still 19% less than 1994. The lower prices realized in 1995 were the result of lower natural gas prices, and the fact that an increased portion of the company's gas production was from areas that contain leaner gas that is either not processed for liquids or con-

For the Year Ended June 30,	1996		1995	
	Production (MMcfe)	Percent of total	Production (MMcfe)	Percent of total
Giddings:				
Navasota River	28,360	47%	16,881	53%
Independence	11,601	19	3,784	12
Other Giddings	7,205	12	5,976	19
Oklahoma:				
Knox	3,901	6	1,255	4
Golden Trend	2,758	5	1,880	6
Sholem Alechem	2,010	3	749	2
All Other Fields	4,355	8	1,422	4
Total Production	60,190	100%	31,947	100%

tains less energy value (Btu's) per Mcf. The company anticipates gas production in Louisiana will receive premium prices at least equivalent to Henry Hub indexes due to the high Btu content and favorable market location of the production.

Gas Marketing Sales

In December 1995, the company entered into the gas marketing business by acquiring all of the outstanding stock of an Oklahoma City-based natural gas marketing company for total consideration of $725,000. This subsidiary provides natural gas marketing services including commodity price structuring, contract administration and nomination services for the company, its partners and other natural gas producers in the geographical areas in which the company is active.

As a result of this purchase, the company realized $28.4 million in gas marketing sales for third parties in fiscal 1996, with corresponding costs of gas marketing sales of $27.5 million resulting in a gross margin of $0.9 million. There were no gas marketing activities in 1995 or 1994.

Oil and Gas Service Operations

Revenues from oil and gas service operations were $6.3 million in fiscal 1996, down 28% from $8.8 million in fiscal 1995, and down 2% from $6.4 million in 1994. The related costs and expenses of these operations were $4.9 million, $7.7 million and $5.2 million for the three years ended June 30, 1996, 1995 and 1994, respectively. The gross profit margin of 22% in fiscal 1996 was up from the 12% margin in fiscal 1995, and up slightly from the 19% gross margin in fiscal 1994. 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.

In June 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 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. 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 will be amortized to income over the estimated useful lives of the Peak assets. The company's investment in Peak will be accounted for using the equity method.

Interest and Other

Interest and other income for fiscal 1996 was $3.8 million which compares to $1.5 million in 1995 and $1 million in 1994. 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. During 1995 and 1994, the company did not incur any such gains on sale of assets or basis losses.

Production Expenses and Taxes

Production expenses and taxes, which include lifting costs and production and excise taxes, increased to $8.3 million in fiscal 1996, as compared to $4.3 million in fiscal 1995, and $3.6 million in fiscal 1994. These increases on a year-to-year basis were primarily the result of increased production. On a Mcfe production unit basis, production expenses and taxes increased to $0.14 per Mcfe as compared to $0.13 per Mcfe in fiscal 1995 and $0.36 per Mcfe in 1994. Severance tax exemptions for production were available in fiscal 1996 and 1995, and certain of the exemptions in Giddings are applicable for production through 2001 for wells spud prior to September 1, 1996, and, on a more limited basis, for qualifying wells spud thereafter. The company expects that operating costs in fiscal 1997 will increase based on the company's expansion of drilling efforts into the Louisiana Trend and the Williston Basin, because both are oil prone areas with significant associated water production, which generally have higher operating costs than gas prone areas, and because limited severance tax exemptions will be applicable in these areas as compared to existing exemptions in Giddings.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization ("DD&A") of oil and gas properties for fiscal 1996 was $50.9 million, $25.5 million higher than fiscal 1995's expense of $25.4 million, and $42.8 million higher than fiscal 1994's expense of $8.1 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, increased to $0.85 in fiscal 1996 compared to $0.80 in fiscal 1995 and 1994. The company's DD&A rate in the future will be a function of the results of future acquisition, exploration, development and production results. The company's rate will increase in fiscal 1997 based on projected higher finding costs for the Louisiana Trend.

Depreciation and Amortization of Other Assets

Depreciation and amortization ("D&A") of other assets increased to $3.2 million in fiscal 1996, compared to $1.8 million in fiscal 1995, and $1.9 million in 1994. This increase in fiscal 1996 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 the Senior Notes in May 1995 and in April 1996. The company anticipates an increase in D&A in fiscal 1997 as a result of a full year of debt issuance cost amortization on the 9.125% Senior Notes issued in April 1996 and higher building depreciation expense on the company's corporate offices, offset by a reduction in depreciation expense associated with the sale of the service company assets.

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 $4.8 million in fiscal 1996, up 33% from $3.6 million in fiscal 1995, and up from $3.1 million in fiscal 1994. The increases in fiscal 1996 compared to 1995 and 1994 result primarily from increased personnel expenses required by the company's growth. The company capitalized $1.7 million of internal costs in fiscal 1996 directly related to the company's oil and gas exploration and development efforts, as compared to $0.6 million in 1995 and $ 1.0 million in 1994. The company anticipates that G&A costs for fiscal 1997 will increase by approximately 25% as a result of the company's continued growth and increased budgets for exploration and development activities, increasing operations activities, and attendant personnel and overhead requirements.

Interest and Other

Interest and other expense increased to $13.7 million in fiscal 1996 as compared to $6.6 million in 1995 and $2.7 million in fiscal 1994. Interest expense in the fourth quarter of fiscal 1996 was approximately $4 million, reflecting the issuance of $120 million of 9.125% Senior Notes in April 1996. In addition to the interest expense reported, the company capitalized $6.4 million of interest during fiscal 1996, as compared to $1.6 million capitalized in 1995 and $0.4 million in 1994. Interest expense will increase significantly in fiscal 1997 as compared to 1996 as a result of the 9.125% Senior Notes issued in April 1996.

Income Tax Expense

The company recorded income tax expense of $12.9 million in fiscal 1996, as compared to $6.3 million in fiscal 1995, and $1.3 million in 1994. All of the income tax expense in 1996 was deferred due to a current year tax net operating loss resulting from the company's active drilling program. A substantial portion of the company's drilling costs are currently deductible for income tax purposes. The effective tax rate was approximately 35.5% in fiscal 1996 compared to a tax rate of 35% in 1995 and 24% in 1994. The company anticipates an effective tax rate of approximately 36.5% for fiscal 1997 as a result of Louisiana state taxes and higher activity levels in Louisiana. Based upon the anticipated level of drilling activities in fiscal 1997, the company anticipates that substantially all of its fiscal 1997 income tax expense will be deferred.

Hedging

Periodically the company utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include swap arrangements that establish an index-related price above which the company pays the hedging partner and below which the company is paid by the hedging partner, the purchase of index-related puts that provide for a "floor" price to the company to be paid by the counter-party to the extent the price of the commodity is below the contracted floor, and basis protection swaps. Recognized gains and losses on hedge contracts are reported as a component of the related transaction. Results from hedging transactions are reflected in oil and gas sales to the extent related to the company's oil and gas production.

As of June 30, 1996, the company had NYMEX-based crude oil swap agreements for 1,000 Bbl per day for July 1, 1996 through August 31, 1996 at an average price of $17.85 per Bbl. The counter-party has the option exercisable monthly for an additional 1,000 Bbl per day for the period July 1, 1996 through December 31, 1996 to cause a swap if the price exceeds an average $17.74 per Bbl. The actual settlements for July and August resulted in a $0.5 million payment to the counter-party. The company estimates, based on NYMEX prices as of August 30, 1996, that the effect of the September through December hedges would be a $0.4 million payment to the counter-party.

The company has purchased Houston Ship Channel put options which guarantee the company an average floor price of $2.21/Mmbtu for 20,000 Mmbtu per day for the period of November 1, 1996 through February 28, 1997. The average cost of these puts was $0.14 per Mmbtu.

As of June 30, 1996, the company had NYMEX-based natural gas swaps and NYMEX/Houston Ship Channel Basis swaps for the months of July through October, 1996. These transactions resulted in payments to the company's counter-party of approximately $2 million for the month of July 1996 and $1.5 million for the month of August 1996. The company estimates, based on NYMEX prices as of August 30, 1996, that the effect of the September and October hedges would be a $0.2 million payment to the counter-party.

The company has only limited involvement with derivative financial instruments, as defined in SFAS No. 119 "Disclosure About Derivative Financial Instruments and Fair Value of Financial Instruments" and does not use them for trading purposes. The company's 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 to its counter-parties and to basis risk.

LIQUIDITY AND CAPITAL RESOURCES

Financing Activities

On April 9, 1996, the company completed a public offering of 2,475,000 shares of Common Stock at a price of $35.33 per share resulting in net proceeds to the company of approximately $82.1 million. On April 12, 1996, the underwriters exercised an over-allotment option to purchase an additional 519,750 shares of Common Stock at a price of $35.33 per share, resulting in additional net proceeds to the company of approximately $17.3 million.

On April 9, 1996, the company also concluded the sale of $120 million of 9.125% Senior Notes due 2006 (the "9.125% Senior Notes"), which offering resulted in net proceeds to the company of approximately $116 million. The 9.125% Senior Notes were issued at 99.931% of par. Approximately $44 million of the proceeds of these offerings was used to retire all amounts outstanding under the company's revolving credit facility. The company may, at its option, redeem prior to April 15, 1999 up to $42 million principal amount of the 9.125% Senior Notes at 109.125% of the principal amount thereof from the proceeds of any equity offering. The 9.125% Senior Notes are redeemable at the option of the company at any time at the redemption or make-whole prices set forth in the Indenture.

In fiscal 1995, cash flows from financing activities were $97.3 million, largely as the result of issuance of $90 million of 10.5% Senior Notes due 2002 (the "10.5% Senior Notes"). The 10.5% Senior Notes are redeemable at the option of the company at any time on or after June 1, 1999. The company may also redeem at its option at any time prior to June 1, 1998 up to $30 million of the 10.5% Senior Notes with the proceeds of an equity offering at 110% of the principal amount thereof.

In fiscal 1994, the company received proceeds from long term borrowings of $48.8 million, primarily from the issuance of $47.5 million of 12% Senior Notes due 2001 (the "12% Senior Notes") and warrants to purchase 2,190,937 shares of the company's Common Stock at an aggregate exercise price of $4,870. The 12% Senior Note Indenture provides for mandatory redemption of $11.9 million on each of March 1, 1998, 1999 and 2000. The 12% Senior Notes are redeemable at the option of the company at any time on or after March 1, 1998.

All of the company's subsidiaries except Chesapeake Gas Development Corporation ("CGDC") and Chesapeake Energy Marketing, Inc. ("CEMI") have fully and unconditionally guaranteed on a joint and several basis all three issues of Senior Notes, and the securities of the guaranteeing subsidiaries have been pledged to secure obligations under the 12% Senior Notes. See Note 2 of Notes to the company's Consolidated Financial Statements included in this report. The Senior Note Indentures contain certain covenants, including covenants limiting the company and the guaranteeing 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 guaranteeing subsidiaries, mergers or consolidations, and transactions with affiliates. The company is obligated to repurchase the Senior Notes in the event of a change of control, the sale of certain assets or failure to maintain a specified ratio of assets to debt.

Financial Flexibility and Liquidity

The company had working capital of approximately $0.3 million at June 30, 1996. Additionally, the company has unused revolving credit facility commitments that have been increased to $75 million. The total facility size has been set at $125 million, subject to certain borrowing base and Senior Note Indentures limitations. This facility provides for interest at the Union Bank reference rate (8.25% at June 30, 1996), or at the option of the company the Eurodollar rate plus 1.375% to 1.875%, depending on the ratio of the amount outstanding to the borrowing base. Although the Senior Note Indentures contain various restrictions on additional indebtedness, based on asset values as of June 30, 1996 the company estimates it could borrow up to $106 million within these restrictions.

The company also maintains a limited recourse bank facility with an amount outstanding of $12.9 million as of June 30, 1996 secured by producing oil and gas properties owned by the company's wholly-owned subsidiary CGDC. This facility provides for interest at the Union Bank reference rate (8.25% at June 30, 1996). The facility has not been guaranteed by the company or any of its other subsidiaries and is recourse only to the assets of CGDC. CGDC used proceeds borrowed under this facility to acquire producing oil and gas properties from Chesapeake Exploration Limited Partnership. The terms of the facility prohibit the payment of dividends by CGDC.

Debt ratings for the Senior Notes are Ba3 by Moody's Investors Service and B+ by Standard & Poors Corporation. Both Moody's and S&P upgraded their ratings during the year. The company's long-term debt represented 60% of total capital at June 30, 1996. The company's goal is to over time achieve an investment grade senior debt rating.

Operating Cash Flows

Cash provided by operating activities was $121 million in fiscal 1996, as compared to $54.7 million in 1995, and $19.4 million in 1994. Operating cash flows for 1996 include enhanced earnings primarily as a result of increased oil and gas production. Other major factors affecting cash flows for 1996, 1995 and 1994 were increases in non-cash charges and cash flows provided by changes in the components of assets and liabilities. Cash provided by operating activities is expected to be the primary source for meeting forecasted cash requirements in 1997.

Investing Cash Flows

Significantly higher cash was used in fiscal 1996 for development, exploration and acquisition of oil and gas properties as compared to fiscal 1995 and 1994. Approximately $336 million was expended by the company in 1996 (net of proceeds from sales of leasehold and equipment, and from providing certain oilfield services), as compared to $106 million in 1995, an increase of $230 million, or approximately 216%. In fiscal 1994, the company expended $27 million (net of proceeds from sale of leasehold, equipment and other) for development and exploration activities. Net cash proceeds received by the company for sales of oil and gas equipment, leasehold and other services decreased to approximately $11 million in fiscal 1996 as compared to $15 million in 1995. In fiscal 1996, other property and equipment additions were $8.8 million, primarily as a result of the purchase of additional office buildings in the company's headquarters complex in Oklahoma City.

The company's capital spending is largely discretionary. The company has established a fiscal 1997 capital expenditure budget of approximately $300 million, of which $80 million is budgeted to fund drilling and completion requirements for the development of a portion of its proved undeveloped reserves during fiscal 1997. The company expects to spend approximately $155 million for drilling and completion of non-proved reserves, $10 million for seismic programs and $55 million for acreage acquisition and other corporate purposes. Absent a significant increase in the company's drilling schedule, the company's internally generated cash flow, existing cash resources and credit facilities should be sufficient to fund its operating activities, budgeted capital expenditures, and its debt service obligations in fiscal 1997.

However, the company may seek additional capital in fiscal 1997 to expand its exploration and development activities or reduce outstanding long-term debt. The discretionary nature of nearly all of the company's capital spending permits the company to make adjustments to its budget based upon factors such as oil and gas pricing, exploration and development drilling results, and the continued availability of internally generated or external capital resources.

Forward Looking Statements

The information contained in Management's Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report includes certain forward-looking statements. When used in this document, the words budget, budgeted, anticipate, expects, believes, goals or 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, volatility of oil and gas prices, the need to develop and replace its reserves, the substantial capital expenditures required to fund its operations, environmental risks, drilling and operating risks, risks related to exploration and development drilling, uncertainties about estimates of reserves, competition, government regulation, and the ability of the company to implement its business strategy. Please refer to the company's filings with the SEC.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders of Chesapeake Energy Corporation

We have audited the accompanying consolidated balance sheet of Chesapeake Energy Corporation and its subsidiaries as of June 30, 1996, and the related consolidated statements of income, stockholders' equity and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Chesapeake Energy Corporation and its subsidiaries as of June 30, 1996, and the consolidated results of their operations and their cash flows for the year then ended in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.

Oklahoma City, Oklahoma
September 13, 1996

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders of Chesapeake Energy Corporation

In our opinion, the consolidated balance sheet and the related consolidated statements of income, of cash flows and of stockholders' equity as of and for each of the two years in the period ended June 30, 1995 present fairly, in all material respects, the financial position, results of operations and cash flows of Chesapeake Energy Corporation and its subsidiaries as of and for each of the two years in the period ended June 30, 1995, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the company's management; our responsibility is to express an opinion on these financial statements 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above. We have not audited the consolidated financial statements of Chesapeake Energy Corporation for any period subsequent to June 30, 1995.

PRICE WATERHOUSE LLP

Houston, Texas
September 20, 1995, except for Note 9 which is as of September 23, 1996

Effective July 1, 1996, Price Waterhouse LLP sold its Oklahoma City practice to Coopers & Lybrand L.L.P. and resigned as the company's accountants.

CONSOLIDATED BALANCE SHEETS

June 30,	1996	1995
Assets	($ in thousands)	
Current Assets:		
Cash and cash equivalents	$ 51,638	$ 55,535
Accounts receivable:		
Oil and gas sales	12,687	10,644
Gas marketing sales	6,982	–
Joint interest and other, net of allowances of $340,000 and $452,000, respectively	27,661	26,317
Related parties	2,884	4,386
Inventory	5,163	8,926
Other	2,158	633
Total Current Assets	109,173	106,441
Property and Equipment:		
Oil and gas properties, at cost based on full cost accounting:		
Evaluated oil and gas properties	363,213	165,302
Unevaluated properties	165,441	27,474
Less: accumulated depreciation, depletion and amortization	(92,720)	(41,821)
	435,934	150,955
Other property and equipment	18,162	16,966
Less: accumulated depreciation and amortization	(2,922)	(4,120)
Total Property and Equipment	451,174	163,801
Other Assets	11,988	6,451
Total Assets	$ 572,335	$ 276,693
Liabilities and Stockholders' Equity		
Current Liabilities:		
Notes payable and current maturities of long-term debt	$ 6,755	$ 9,993
Accounts payable	54,514	33,438
Accrued liabilities and other	14,062	7,688
Revenues and royalties due others	33,503	23,786
Total Current Liabilities	108,834	74,905
Long-term debt, net	268,431	145,754
Revenues and royalties due others	5,118	3,779
Deferred income taxes	12,185	7,280
Contingencies and commitments (Note 4)	–	–
Stockholders' equity:		
Preferred Stock, $.01 par value, 2,000,000 shares authorized; zero shares issued and outstanding	–	–
Common Stock, 45,000,000 shares authorized; $.10 par value at June 30, 1996, $.0022 par value at June 30, 1995; 30,079,913 and 26,311,248 shares issued and outstanding at June 30, 1996 and 1995, respectively	3,008	58
Paid-in capital	136,782	30,295
Accumulated earnings	37,977	14,622
Total Stockholders' Equity	177,767	44,975
Total Liabilities and Stockholders' Equity	$ 572,335	$ 276,693

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

CONSOLIDATED STATEMENTS OF INCOME

Year Ended June 30,	1996	1995	1994
Revenues:	($ in thousands, except per share data)		
Oil and gas sales	$ 110,849	$ 56,983	$ 22,404
Gas marketing sales	28,428	–	–
Oil and gas service operations	6,314	8,836	6,439
Interest and other	3,831	1,524	981
Total Revenues	149,422	67,343	29,824
Costs and expenses:			
Production expenses and taxes	8,303	4,256	3,647
Gas marketing expenses	27,452	–	–
Oil and gas service operations	4,895	7,747	5,199
Oil and gas depreciation, depletion and amortization	50,899	25,410	8,141
Depreciation and amortization of other assets	3,157	1,765	1,871
General and administrative	4,828	3,578	3,135
Interest and other	13,679	6,627	2,676
Total Costs and Expenses	113,213	49,383	24,669
Income Before Income Taxes	36,209	17,960	5,155
Income Tax Expense	12,854	6,299	1,250
Net Income	$ 23,355	$ 11,661	$ 3,905
Net income per common share:			
Primary	$ .80	$ .42	$ .16
Fully-diluted	$ .79	$ .41	$ .16
Weighted average common and common equivalent shares outstanding:			
Primary	29,171	27,936	24,120
Fully-diluted	29,461	28,303	24,183

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended June 30,	1996	1995	1994
Cash flows from operating activities:		*($ in thousands)*	
Net income	$ 23,355	$ 11,661	$ 3,905
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	52,768	26,628	9,455
Deferred taxes	12,854	6,299	1,250
Amortization of loan costs	1,288	548	557
Amortization of bond discount	563	567	138
Bad debt expense	114	308	222
Purchases and sales of trading securities, net	622	–	–
Gain on sale of fixed assets	(2,511)	(108)	–
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(3,524)	(22,510)	(7,773)
(Increase) decrease in inventory	78	(1,203)	(304)
(Increase) decrease in other current assets	(1,525)	614	(726)
Increase (decrease) in accounts payable, accrued liabilities and other	25,834	19,387	10,077
Increase in current and non-current revenues and royalties due others	11,056	12,540	2,622
Cash provided by operating activities	120,972	54,731	19,423
Cash flows from investing activities:			
Exploration, development and acquisition of oil and gas properties	(347,294)	(120,985)	(34,654)
Proceeds from sale of oil and gas equipment, leasehold and other	11,416	15,107	7,598
Other proceeds from sales	698	1,104	765
Investment in gas marketing company, net of cash acquired	(363)	–	–
Other property and equipment additions	(8,846)	(7,929)	(2,920)
Cash used in investing activities	(344,389)	(112,703)	(29,211)
Cash flows from financing activities:			
Proceeds from issuance of Common Stock	99,498	–	–
Proceeds from long-term borrowings	166,667	128,834	48,800
Payments on long-term borrowings	(48,634)	(32,370)	(25,738)
Placement fee on Senior Notes and Warrants	–	–	(1,900)
Cash received from exercise of stock options	1,989	818	–
Cash provided by financing activities	219,520	97,282	21,162
Net increase (decrease) in cash and cash equivalents	(3,897)	39,310	11,374
Cash and cash equivalents, beginning of period	55,535	16,225	4,851
Cash and cash equivalents, end of period	$ 51,638	$ 55,535	$ 16,225
Supplemental disclosure of cash flow information			
Cash payments for:			
Interest	$ 17,179	$ 6,488	$ 1,467
Income taxes	$ –	$ –	$ 109

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

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

The company has a financing arrangement with a vendor to supply certain oil and gas equipment inventory. The total amounts owed at June 30, 1996, 1995 and 1994 were $3,156,000, $6,513,000 and $5,952,000, respectively. No cash consideration is exchanged for inventory under this financing arrangement until actual draws on the inventory are made.

In fiscal 1996 and 1995, the company recognized income tax benefits of $7,950,000 and $1,229,000, 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 issuances of $90 million of 10.5% Senior Notes in May 1995 and $120 million of 9.125% Senior Notes in April 1996 are net of $2.7 million and $3.9 million, respectively, in offering fees and expenses which were deducted from the actual cash received.

On March 31, 1994, the company issued 8,000 units (see Note 2) to Trust Company of the West ("TCW") primarily in consideration for the surrender of 576,923 shares of the company's 9% convertible preferred stock, including its rights to dividends, warrants to purchase Common Stock and an overriding royalty interest.

In February 1994, pending litigation was settled pursuant to an agreement requiring COI to pay $1.25 million, of which $250,000 plus interest was paid in July 1994, and the balance of which was paid in June 1995.

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Year Ended June 30,	1996	1995	1994
		($ in thousands)	
Preferred Stock:			
Balance, beginning of period	$ –	$ –	$ 6
Exchange of 576,923 shares of Preferred Stock	–	–	(6)
Balance, end of period	–	–	–
Common Stock:			
Balance, beginning of period	58	51	51
Issuance of 2,994,750 shares of Common Stock	299	–	–
Exercise of stock options and warrants	79	7	–
Change in par value from $.0022 to $.10	2,572	–	–
Balance, end of period	3,008	58	51
Common Stock Warrants:			
Balance, beginning of period	–	5	–
Issuance of Common Stock Warrants	–	–	5
Exercise of Common Stock Warrants	–	(5)	–
Balance, end of period	–	–	5
Paid-in Capital:			
Balance, beginning of period	30,295	28,243	32,704
Exchange of Preferred Stock	–	–	(7,494)
Issuance of Common Stock Warrants	–	–	3,033
Exercise of stock options and warrants	1,910	823	–
Issuance of Common Stock	105,516	–	–
Offering expenses and other	(6,317)	–	–
Tax benefit from exercise of stock options	7,950	1,229	–
Change in par value from $.0022 to $.10	(2,572)	–	–
Balance, end of period	136,782	30,295	28,243
Accumulated Earnings (deficit):			
Balance, beginning of period	14,622	2,961	(1,329)
Net income	23,355	11,661	3,905
Preferred dividends	–	–	(340)
Cancellation of preferred dividends	–	–	725
Balance, end of period	37,977	14,622	2,961
Total Stockholders' Equity:	$ 177,767	$ 44,975	$ 31,260

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

NOTE TO CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake Energy Corporation (the "company" or "parent") include the accounts of Chesapeake Operating, Inc. ("COI"), Chesapeake Exploration Limited Partnership ("CEX"), a limited partnership, Chesapeake Gas Development Corporation ("CGDC"), Chesapeake Energy Marketing, Inc. ("CEMI"), Lindsay Oil Field Supply, Inc.("LOF"), Sander Trucking Company, Inc. ("STCO") and subsidiaries of those entities. All significant intercompany accounts and transactions have been eliminated.

In December 1995, the company entered into the gas marketing business by acquiring all of the outstanding stock of an Oklahoma City-based natural gas marketing company for total consideration of $725,000. This subsidiary was subsequently named Chesapeake Energy Marketing, Inc. CEMI provides natural gas marketing services including commodity price structuring, contract administration and nomination services for the company, its partners and other natural gas producers in the geographical areas in which the company is active.

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.

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. The company's oil and gas reserves are estimated annually by independent petroleum engineers. The average composite rates used for depreciation, depletion and amortization were $0.85, $0.80 and $0.80 per equivalent Mcf in 1996, 1995, and 1994, 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. Unamortized costs as reduced by related deferred taxes are subject to a ceiling which limits such amounts to the estimated present value of oil and gas reserves, reduced by operating expenses, future development costs and income taxes. The costs of unproved properties are excluded from amortization until the properties are evaluated.

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 $35 million, subject to adjustment for activity after the effective date of January 1, 1996. The properties are located in the Knox and Golden Trend fields of southern Oklahoma, most of which are operated by the company.

Other Property and Equipment

Other property and equipment primarily consists of vehicles, office buildings and equipment, and software. Major renewals and improvements 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 over the estimated useful lives of the assets, which range from three to 30 years.

Leases

Included in other property and equipment in the consolidated balance sheets is computer equipment and software held under capital leases. Minimum lease payments under these capital leases and other operating leases are as follows:

	Capital Leases	Operating Leases
	($ in thousands)	
1997	$ 62	$133
1998	62	58
1999	15	53
2000	0	0
2001	0	0
Total minimum lease payments	139	$244
Less: amount relating to interest	(20)	
Present value of minimum payments	$119	

Capitalized Interest

During fiscal 1996, 1995 and 1994, interest of approximately $6,428,000, $1,574,000 and $356,000 was capitalized on significant investments in unproved properties that are not being currently depreciated, depleted, or amortized and on which exploration or development activities are in progress.

Service Operations

Certain subsidiaries of the company performed contractual services on wells the company operates 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 statements of income include amounts derived from certain of the contractual services provided. The company's economic interest in its oil and gas properties is 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 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 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. 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 will be amortized to income over the estimated useful lives of the Peak assets. The company's investment in Peak will be accounted for using the equity method.

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 Per Share

Primary and fully diluted earnings per share for all periods have been computed based upon the weighted average number of shares of Common Stock outstanding after giving retroactive effect to all stock splits and the issuance of common stock equivalents when their effect is dilutive. Dilutive options or warrants which are issued during a period or which expire or are cancelled during a period are reflected in both primary and fully diluted earnings per share computations for the time they were outstanding during the period being reported upon.

Gas Imbalances

The company follows the "sales method" of accounting for its oil and gas revenue whereby the company recognizes sales revenue on all oil or 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 reserves on the underlying properties. The company's net imbalance positions at June 30, 1996 and 1995 were not material.

Hedging

The company periodically uses certain instruments to hedge its exposure to price fluctuations on oil and natural gas transactions. Recognized gains and losses on hedge contracts are reported as a component of the related transaction. Results for hedging transactions are reflected in oil and gas sales to the extent related to the company's oil and gas production.

Debt Issue Costs

Other assets relate primarily to debt issue costs associated with the issuance of the 12% Senior Notes on March 31, 1994, the 10.5% Senior Notes on May 25, 1995, and the 9.125% Senior Notes on April 9, 1996 (see Note 2). The remaining unamortized costs on these issuances of Senior Notes at June 30, 1996 totaled $8.7 million and are being amortized over the life of the Senior Notes.

Stock Options

In October 1995, the Financial Accounting Standards Board issued Statement No. 123 ("SFAS 123"), "Accounting for Stock Based Compensation". As permitted by SFAS 123, the company plans to continue to retain its current method of accounting for stock compensation and adopt the disclosure requirements of this Statement in fiscal 1997.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for the years ended June 30, 1995 and 1994 to conform to the presentation used for the June 30, 1996 consolidated financial statements.

2. SENIOR NOTES

On April 9, 1996, the company completed an offering of $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 at the redemption or make-whole prices set forth in the indenture. 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 completed a private offering of $90 million principal amount of 10.5% Senior Notes due 2002 ("10.5% Senior Notes"). The 10.5% Senior Notes are redeemable at the option of the company at any time on or after June 1, 1999. The company may also redeem at its option any time prior to June 1, 1998 up to $30 million of the 10.5% Senior Notes at 110% of the principal amount thereof with the proceeds of an equity offering. In September 1995, the company exchanged the 10.5% Senior Notes for substantially identical notes in a registered exchange offer (also referred to as the "10.5% Senior Notes").

On March 31, 1994, the company completed a private offering of 47,500 Units consisting of an aggregate of $47.5 million principal amount of 12% Senior Notes due 2001 ("12% Senior Notes") and warrants ("Warrants") to purchase 2,190,937 shares of the company's Common Stock at an aggregate exercise price of $4,870. The Warrants were valued at $3 million creating a discount on the 12% Senior Notes. All of the Warrants were subsequently exercised. In exchange for 8,000 Units, the company acquired from Trust Company of the West ("TCW") 576,923 shares of the company's 9% cumulative convertible preferred stock and all rights to dividends thereon, warrants to purchase 1,404,004 shares of the company's Common Stock and 50% of an outstanding overriding royalty interest held by TCW. The 12% Senior Notes are redeemable at the option of the company at any time on or after March 1, 1998 at an initial premium of 106% of the principal amount thereof, declining to no premium in 2000. The company is required to redeem $11,875,000 principal amount of 12% Senior Notes on each of March 1, 1998, 1999 and 2000. In November 1994, the company exchanged the 12% Senior Notes for substantially identical notes in a registered exchange offer (also referred to as the "12% Senior Notes").

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 12% Senior Notes, the 10.5% Senior Notes and the 9.125% 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 Notes): COI, LOF, STCO, Whitmire Dozer Service, Inc. and CEX (collectively, the "Subsidiary Guarantors"). The only subsidiaries of the company that are not Subsidiary Guarantors are CGDC and CEMI (together, the "Non-Guarantor Subsidiaries"). Each of the Subsidiary Guarantors is a direct or indirect wholly-owned subsidiary of the company. The securities of the Subsidiary Guarantors have been pledged to secure performance of the company's obligations under the 12% Senior Notes. The only affiliate securities constituting a substantial portion of the collateral for the 12% Senior Notes are the partnership interests in CEX.

The 12%, 10.5% and 9.125% Senior Note Indentures contain certain covenants, including covenants limiting the company and the Subsidiary Guarantors 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 Subsidiary Guarantors; mergers or consolidations; and transactions with affiliates. The company is also obligated to repurchase 12%, 10.5% and 9.125% Senior Notes if it fails to maintain a specified ratio of assets to debt and in the event of a change of control or certain asset sales.

The company's bank credit agreement prohibits any distributions by CEX to its partners (the company and COI) if the maturity of any obligations to the lender has been accelerated. The pledge agreement relating to the 12% Senior Notes requires that all dividends and distributions from Subsidiary Guarantors be paid to the collateral agent thereunder upon an event of default under the 12% Senior Notes Indenture. There are no other restrictions on the payment of cash dividends by Subsidiary Guarantors.

CEX is a limited partnership which is 10% owned by COI, as sole general partner, and 90% owned directly by the company, as sole limited partner. CEX owns 94% and CGDC owns 6% of the company's producing oil and gas properties, based on the present value of future net revenue at June 30, 1996 (discounted at 10%).

Set forth below are condensed consolidating financial statements of CEX, the other Subsidiary Guarantors, all Subsidiary Guarantors combined, the Non-Guarantor Subsidiaries and the company. The CEX limited partnership condensed financial statements were prepared on a separate entity basis as reflected in the company's books and records and include all material costs of doing business as if the partnership were on a stand-alone basis except that interest is not charged or allocated. No provision has been made for income taxes because the partnership is not a taxpaying entity. Separate audited financial statements of each Subsidiary Guarantor, other than CEX, have not been provided because management has determined that they are not material to investors.

CONDENSED CONSOLIDATING BALANCE SHEET

As of June 30, 1996 ($ in thousands)	Subsidiary Guarantors CEX	Subsidiary Guarantors Others	Subsidiary Guarantors Combined	Non-Guarantor Subsidiaries	Company (Parent)	Eliminations	Consolidated
Assets							
Current Assets:							
Cash and cash equivalents	$ –	$ 4,061	$ 4,061	$ 2,751	$ 44,826	$ –	$ 51,638
Accounts receivable	14,778	29,302	44,080	7,723	–	(1,589)	50,214
Inventory	–	4,947	4,947	216	–	–	5,163
Other	1,891	264	2,155	3	–	–	2,158
Total Current Assets	16,669	38,574	55,243	10,693	44,826	(1,589)	109,173
Property and equipment:							
Oil and gas properties	346,821	(8,211)	338,610	24,603	–	–	363,213
Unevaluated leasehold	165,441	–	165,441	–	–	–	165,441
Other property and equipment	–	9,608	9,608	61	8,493	–	18,162
Less: accumulated depreciation, depletion and amortization	(84,726)	(2,467)	(87,193)	(8,007)	(442)	–	(95,642)
	427,536	(1,070)	426,466	16,657	8,051	–	451,174
Investments in subsidiaries and intercompany advances	56,055	463,331	519,386	8,132	382,388	(909,906)	–
Other assets	694	1,616	2,310	940	8,738	–	11,988
Total Assets	$ 500,954	$ 502,451	$1,003,405	$ 36,422	$ 444,003	$ (911,495)	$ 572,335
Liabilities and Stockholders' Equity							
Current Liabilities:							
Notes payable and current maturities of long-term debt	$ –	$ 3,846	$ 3,846	$ 2,880	$ 29	$ –	$ 6,755
Accounts payable and other	789	90,280	91,069	7,339	5,260	(1,589)	102,079
Total Current Liabilities	789	94,126	94,915	10,219	5,289	(1,589)	108,834
Long-term debt	–	2,113	2,113	10,020	256,298	–	268,431
Revenues and royalties due others	–	5,118	5,118	–	–	–	5,118
Deferred income taxes	–	23,950	23,950	1,335	(13,100)	–	12,185
Intercompany payables	413,726	410,581	824,307	8,182	73,647	(906,136)	–
Stockholders' equity:							
Common Stock	–	117	117	2	2,891	(2)	3,008
Other	86,439	(33,554)	52,885	6,664	118,978	(3,768)	174,759
	86,439	(33,437)	53,002	6,666	121,869	(3,770)	177,767
Total Liabilities and Stockholders' Equity	$ 500,954	$ 502,451	$1,003,405	$ 36,422	$ 444,003	$ (911,495)	$ 572,335

CONDENSED CONSOLIDATING BALANCE SHEET

As of June 30, 1995 ($ in thousands)	Subsidiary Guarantors CEX	Subsidiary Guarantors Others	Combined	Non-Guarantor Subsidiaries	Company (Parent)	Eliminations	Consolidated
Assets							
Current Assets:							
Cash and cash equivalents	$ –	$ 53,227	$ 53,227	$ 5	$ 2,303	$ –	$ 55,535
Accounts receivable	9,867	30,693	40,560	777	10	–	41,347
Inventory	–	8,895	8,895	31	–	–	8,926
Other	–	633	633	–	–	–	633
Total Current Assets	9,867	93,448	103,315	813	2,313	–	106,441
Property and equipment:							
Oil and gas properties	163,521	(16,723)	146,798	18,504	–	–	165,302
Unevaluated leasehold	27,474	–	27,474	–	–	–	27,474
Other property and equipment	–	12,199	12,199	–	4,767	–	16,966
Less: accumulated depreciation, depletion and amortization	(36,959)	(3,847)	(40,806)	(4,861)	(274)	–	(45,941)
	154,036	(8,371)	145,665	13,643	4,493	–	163,801
Investments in subsidiaries and intercompany advances	17,559	181,914	199,473	–	176,795	(376,268)	–
Other assets	776	41	817	123	5,511	–	6,451
Total Assets	$ 182,238	$ 267,032	$ 449,270	$ 14,579	$ 189,112	$ (376,268)	$ 276,693
Liabilities and Stockholders' Equity							
Current Liabilities:							
Notes payable and current maturities of long-term debt	$ –	$ 7,757	$ 7,757	$ 2,200	$ 36	–	$ 9,993
Accounts payable and other	516	61,777	62,293	–	2,619	–	64,912
Total Current Liabilities	516	69,534	70,050	2,200	2,655	–	74,905
Long-term debt	10	1,326	1,336	8,600	135,818	–	145,754
Revenues and royalties due others	–	3,779	3,779	–	–	–	3,779
Deferred income taxes	–	9,621	9,621	164	(2,505)	–	7,280
Intercompany payables	140,236	201,959	342,195	3,307	30,766	(376,268)	–
Stockholders' equity:							
Common Stock	–	31	31	1	58	(32)	58
Other	41,476	(19,218)	22,258	307	22,320	32	44,917
	41,476	(19,187)	22,289	308	22,378	–	44,975
Total Liabilities and Stockholders' Equity	$ 182,238	$ 267,032	$ 449,270	$ 14,579	$ 189,112	$ (376,268)	$ 276,693

CONDENSED CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended June 30, 1996 ($ in thousands)	Subsidiary Guarantors CEX	Subsidiary Guarantors Others	Combined	Non-Guarantor Subsidiaries	Company (Parent)	Eliminations	Consolidated
Revenues							
Oil and gas sales	$ 103,712	$ –	$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	–	–	–	6,314
Interest and other	(1,473)	3,390	1,917	238	1,676	–	3,831
	102,239	9,704	111,943	42,095	1,676	(6,292)	149,422
Costs and expenses							
Production expenses and taxes	7,225	332	7,557	746	–	–	8,303
Gas marketing expenses	–	–	–	33,744	–	(6,292)	27,452
Oil and gas service operations	–	4,895	4,895	–	–	–	4,895
Oil and gas depreciation, depletion and amortization	48,333	–	48,333	2,566	–	–	50,899
Other depreciation and amortization	258	1,666	1,924	73	1,160	–	3,157
General and administrative	1,090	2,593	3,683	496	649	–	4,828
Interest and other	370	138	508	711	12,460	–	13,679
	57,276	9,624	66,900	38,336	14,269	(6,292)	113,213
Income (loss) before income taxes	44,963	80	45,043	3,759	(12,593)	–	36,209
Income tax expense (benefit)	–	15,990	15,990	1,335	(4,471)	–	12,854
Net income (loss)	$ 44,963	$ (15,910)	$ 29,053	$ 2,424	$ (8,122)	$ –	$ 23,355

For the Year Ended June 30, 1995 ($ in thousands)	Subsidiary Guarantors CEX	Subsidiary Guarantors Others	Combined	Non-Guarantor Subsidiaries	Company (Parent)	Eliminations	Consolidated
Revenues							
Oil and gas sales	$ 55,417	$ –	$ 55,417	$ 1,566	$ –	$ –	$ 56,983
Oil and gas service operations	–	8,836	8,836	–	–	–	8,836
Interest and other	–	1,394	1,394	–	130	–	1,524
	55,417	10,230	65,647	1,566	130	–	67,343
Costs and expenses							
Production expenses and taxes	3,494	551	4,045	211	–	–	4,256
Oil and gas service operations	–	7,747	7,747	–	–	–	7,747
Oil and gas depreciation, depletion and amortization	24,769	6	24,775	635	–	–	25,410
Other depreciation and amortization	138	1,107	1,245	5	515	–	1,765
General and administrative	931	1,689	2,620	58	900	–	3,578
Interest and other	352	218	570	184	5,873	–	6,627
	29,684	11,318	41,002	1,093	7,288	–	49,383
Income (loss) before income taxes	25,733	(1,088)	24,645	473	(7,158)	–	17,960
Income tax expense (benefit)	–	8,639	8,639	165	(2,505)	–	6,299
Net Income (loss)	$ 25,733	$ (9,727)	$ 16,006	$ 308	$ (4,653)	$ –	$ 11,661

CONDENSED CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended June 30, 1994 ($ in thousands)	Subsidiary Guarantors CEX	Others	Combined	Non-Guarantor Subsidiaries	Company (Parent)	Eliminations	Consolidated
Revenues							
Oil and gas sales	$ 22,404	$ –	$ 22,404	$ –	$ –	$ –	$ 22,404
Oil and gas service operations	–	6,439	6,439	–	–	–	6,439
Interest and other	–	622	622	–	359	–	981
	22,404	7,061	29,465	–	359	–	29,824
Costs and expenses							
Production expenses and taxes	3,185	462	3,647	–	–	–	3,647
Oil and gas service operations	–	5,199	5,199	–	–	–	5,199
Oil and gas depreciation, depletion and amortization	8,141	–	8,141	–	–	–	8,141
Other depreciation and amortization	171	1,536	1,707	–	164	–	1,871
General and administrative	823	2,169	2,992	–	143	–	3,135
Interest and other	507	1,492	1,999	–	677	–	2,676
	12,827	10,858	23,685	–	984	–	24,669
Income (loss) before income taxes	9,577	(3,797)	5,780	–	(625)	–	5,155
Income tax expense (benefit)	–	1,400	1,400	–	(150)	–	1,250
Net income (loss)	$ 9,577	$ (5,197)	$ 4,380	$ –	$ (475)	$ –	$ 3,905

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended June 30, 1996 ($ in thousands)	Subsidiary Guarantors CEX	Others	Combined	Non-Guarantor Subsidiaries	Company (Parent)	Eliminations	Consolidated
Cash flows from operating activities	$ 91,286	$ 35,582	$ 126,868	$ 4,204	$ (10,100)	$ –	$ 120,972
Cash flows from investing activities							
Oil and gas properties	(329,507)	(16,988)	(346,495)	(6,099)	–	5,300	(347,294)
Proceeds from sales	7,458	9,956	17,414	–	–	(5,300)	12,114
Investment in gas marketing company	–	–	–	266	(629)	–	(363)
Other additions	(177)	(4,506)	(4,683)	(109)	(4,054)	–	(8,846)
	(322,226)	(11,538)	(333,764)	(5,942)	(4,683)	–	(344,389)
Cash flows from financing activities							
Proceeds from borrowings	39,000	1,350	40,350	10,300	116,017	–	166,667
Payments on borrowings	(44,010)	(1,387)	(45,397)	(3,200)	(37)	–	(48,634)
Cash received from exercise of stock options	–	–	–	–	1,989	–	1,989
Cash received from issuance of common stock	–	–	–	–	99,498	–	99,498
Intercompany advances, net	235,950	(73,173)	162,777	(2,616)	(160,161)	–	–
	230,940	(73,210)	157,730	4,484	57,306	–	219,520
Net increase (decrease) in cash and cash equivalents	–	(49,166)	(49,166)	2,746	42,523	–	(3,897)
Cash, beginning of period	–	53,227	53,227	5	2,303	–	55,535
Cash, end of period	$ –	$ 4,061	$ 4,061	$ 2,751	$ 44,826	$ –	$ 51,638

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended June 30, 1995 ($ in thousands)	Subsidiary Guarantors CEX	Others	Combined	Non-Guarantor Subsidiaries	Company (Parent)	Eliminations	Consolidated
Cash flows from operating activities	$ 46,753	$ 13,296	$ 60,049	$ 305	$ (4,692)	$ (931)	$ 54,731
Cash flows from investing activities							
Oil and gas properties	(111,980)	(4,896)	(116,876)	(4,109)	–	–	(120,985)
Proceeds from sales	16,579	11,132	27,711	–	–	(11,500)	16,211
Purchase of oil and gas properties	–	–	–	(11,500)	–	11,500	–
Other additions	–	(7,929)	(7,929)	–	–	–	(7,929)
	(95,401)	(1,693)	(97,094)	(15,609)	–	–	(112,703)
Cash flows from financing activities							
Proceeds from borrowings	28,433	1,601	30,034	11,500	87,300	–	128,834
Payments on borrowings	(28,433)	(3,599)	(32,032)	(700)	362	–	(32,370)
Intercompany advances, net	48,648	29,676	78,324	4,509	(83,764)	931	–
Other financing	–	–	–	–	818	–	818
	48,648	27,678	76,326	15,309	4,716	931	97,282
Net increase (decrease) in cash and cash equivalents	–	39,281	39,281	5	24	–	39,310
Cash, beginning of period	–	13,946	13,946	–	2,279	–	16,225
Cash, end of period	$ –	$ 53,227	$ 53,227	$ 5	$ 2,303	$ –	$ 55,535

For the Year Ended June 30, 1994 ($ in thousands)	Subsidiary Guarantors CEX	Others	Combined	Non-Guarantor Subsidiaries	Company (Parent)	Eliminations	Consolidated
Cash flows from operating activities	$ 13,131	$ 7,707	$ 20,838	$ –	$ (1,415)	$ –	$ 19,423
Cash flows from investing activities							
Oil and gas properties	(33,466)	(1,188)	(34,654)	–	–	–	(34,654)
Proceeds from sales	3,268	5,095	8,363	–	–	–	8,363
Other additions	(159)	(1,782)	(1,941)	–	(979)	–	(2,920)
	(30,357)	2,125	(28,232)	–	(979)	–	(29,211)
Cash flows from financing activities							
Proceeds from borrowings	–	8,800	8,800	–	40,000	–	48,800
Payments on borrowings	(10,201)	(15,537)	(25,738)	–	–	–	(25,738)
Intercompany advances, net	27,250	6,715	33,965	–	(33,965)	–	–
Other financing	–	–	–	–	(1,900)	–	(1,900)
	17,049	(22)	17,027	–	4,135	–	21,162
Net increase (decrease) in cash and cash equivalents	(177)	9,810	9,633	–	1,741	–	11,374
Cash, beginning of period	177	4,136	4,313	–	538	–	4,851
Cash, end of period	$ –	$ 13,946	$ 13,946	$ –	$ 2,279	$ –	$ 16,225

3. NOTES PAYABLE AND LONG-TERM DEBT

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

($ in thousands)	June 30, 1996	1995
9.125% Senior Notes (see Note 2)	$ 120,000	$ –
Discount on 9.125% Senior Notes	(81)	–
10.5% Senior Notes (see Note 2)	90,000	90,000
12% Senior Notes (see Note 2)	47,500	47,500
Discount on 12% Senior Notes	(1,772)	(2,333)
Term note payable to Union Bank collateralized by CGDC, not guaranteed by the company, variable interest at Union Bank's base rate (8.25% per annum at June 30, 1996), or at Eurodollar rate +1.875% collateralized by CGDC's producing oil and gas properties, payable in monthly installments through November 2002	12,900	10,800
Term note payable to Union Bank, variable interest at Union Bank's base rate or at Eurodollar rate + an incremental rate (8.25% per annum at June 30, 1996), collateralized by CEX's producing oil and gas properties and guaranteed by the company	–	10
Note payable to a vendor, collateralized by oil and gas tubulars, payments due 60 days from shipment of the tubulars	3,156	6,513
Note payable to a bank, variable interest at a referenced base rate + 1.75% (10% per annum at June 30, 1996), collateralized by office buildings, payments due in monthly installments through May 1998	680	686
Notes payable to various entities to acquire oil service equipment, interest varies from 7% to 11% per annum, collateralized by equipment, payments due in monthly installments through December 2000	1,212	2,162
Other collateralized	1,469	230
Other, unsecured	122	179
Total notes payable and long-term debt	275,186	155,747
Less - current maturities	(6,755)	(9,993)
Notes payable and long-term debt, net of current maturities	$ 268,431	$ 145,754

The aggregate scheduled maturities of notes payable and long-term debt for the next five fiscal years ending June 30, 2001 and thereafter were as follows as of June 30, 1996 (in thousands of dollars):

1997	$ 6,755
1998	14,234
1999	13,637
2000	13,344
2001	14,565
After 2001	212,651
	$275,186

In April 1993, CEX entered into an oil and gas reserve-based reducing revolving credit facility (the "Revolving Credit Facility") with Union Bank. The Revolving Credit Facility has been amended from time to time, most recently in September 1996. Concurrent with the September 1996 amendment, the company increased the facility size to $125 million and expanded its bank group with Union Bank remaining as agent.

The maturity date of the Revolving Credit Facility is April 30, 2001. The facility provides for interest at the Union Bank reference rate (8.25% at June 30, 1996) or, at the option of the company the Eurodollar rate plus 1.375% to 1.875% depending on the ratio of the amount outstanding to the borrowing base. Borrowings are collateralized by a first priority lien on substantially all of CEX's proved producing reserves, and are unconditionally guaranteed by the company. At June 30, 1996 and 1995 there was $0 and $10,000 outstanding under the Revolving Credit Facility, respectively.

The amount of credit available at any time under the Revolving Credit Facility is the lesser of the commitment amount or the borrowing base. The borrowing base is reduced each month by a specified amount. Both the borrowing base and the monthly reduction amount are redetermined by Union Bank each May 1 and November 1 and may be redetermined at any other time upon the request of CEX or Union Bank. To the extent the amount outstanding at any time exceeds the borrowing base, CEX must reduce the amount outstanding or add additional collateral. At June 30, 1996, the commitment amount and the borrowing base under the Revolving Credit Facility were $35 million, and the monthly reduction amount was $700,000. The Revolving Credit Facility was amended in September 1996 to provide for a borrowing base and a commitment amount of $75 million, with a monthly reduction amount of $1,750,000. The Revolving Credit Facility contains customary financial covenants, limitations on indebtedness and liabilities, liens, prepayments of other indebtedness (including the 12%, 10.5% and 9.125% Senior Notes) and loans, investments and guarantees by the company and prohibits the payment of dividends on the company's Common Stock.

The company's wholly-owned subsidiary, CGDC, has a credit facility with Union Bank (the "Term Credit Facility"), with an outstanding balance of $12.9 million at June 30, 1996. Collateral for the Term Credit Facility is limited to CGDC's producing oil and gas properties. The Term Credit Facility has not been guaranteed by the company or any of its other subsidiaries and is recourse only to the assets of CGDC. CGDC acquired producing oil and gas properties from CEX in December 1994, June 1995 and December 1995 in exchange for $5.5 million, $6 million and $5.3 million in cash, respectively, using proceeds borrowed under this facility. CGDC has not guaranteed the payment of the company's 12%, 10.5% or 9.125% Senior Notes, nor has the capital stock of CGDC been pledged as collateral for such indebtedness. The terms of the Term Credit Facility prohibit the payment of dividends by CGDC.

4. CONTINGENCIES AND COMMITMENTS

The company is currently involved in various 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 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 June 30, 1997 through June 30, 1998.

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 environmental issues or claims.

5. INCOME TAXES

As discussed in Note 1, the company has adopted SFAS 109. The components of the income tax provision for each of the periods are as follows:

Year Ended June 30,	1996	1995	1994
($ in thousands)			
Current	$ –	$ –	$ –
Deferred	12,854	6,299	1,250
Total	$ 12,854	$ 6,299	$ 1,250

The effective income tax rate differed from the computed "expected" federal income tax rate on earnings before income taxes for the following reasons:

Year Ended June 30,	1996	1995	1994
($ in thousands)			
Computed "expected" income tax provision	$12,673	$ 6,286	$ 1,753
Tax percentage depletion	(238)	(144)	(780)
Other	419	157	277
	$12,854	$ 6,299	$ 1,250

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 June 30,	1996	1995	1994
($ in thousands)			
Deferred tax liabilities:			
Acquisition, exploration and development costs and related depreciation, depletion and amortization	$(63,725)	$(31,220)	$(15,872)
Deferred tax assets:			
Net operating loss carryforwards	50,776	23,414	12,879
Percentage depletion carryforward	764	526	780
	51,540	23,940	13,659
Total Deferred Income Taxes	$(12,185)	$ (7,280)	$ (2,213)

At June 30, 1996, the company had regular tax net operating loss carryforwards of approximately $140 million and alternative minimum tax net operating loss carryforwards of approximately $15 million. These loss carryforward amounts will expire during the years 2007 through 2011. The company also had a percentage depletion carryforward of approximately $2.3 million at June 30, 1996, 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 does not believe that an Ownership Change has occurred as of June 30, 1996.

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 June 30, 1996, 1995 and 1994 the company had accounts receivable for these costs of $2.9 million, $4.4 million and $1.7 million, respectively.

During fiscal 1996, 1995 and 1994, the company incurred legal expenses of $347,000, $516,000 and $631,000, respectively, for legal services provided by the law firm of which a director is a member.

7. EMPLOYEE BENEFIT PLANS

Effective October 1, 1989, the company established a 401(K) profit sharing plan. On December 1, 1993, the company amended the plan and established the Chesapeake Energy Savings and Incentive Plan. On January 1, 1996 the company amended the plan and established the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan (the "Savings and Incentive Stock Bonus Plan"). Eligible employees may make voluntary contributions to the Savings and Incentive Stock Bonus Plan which are matched by the company up to 10% of the employees' annual salary with the company's common stock. The amount of employee contributions is limited as specified in the Savings and Incentive Stock Bonus Plan. The company may, at its discretion, make additional contributions to the Savings and Incentive Stock Bonus Plan. The company contributed $187,000, $95,000 and $70,000 to the Savings and Incentive Stock Bonus Plan during the fiscal years ended June 30, 1996, 1995 and 1994, respectively.

8. MAJOR CUSTOMERS

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

Year		Amount	Percent of oil and gas sales
		($ in thousands)	
1996	Aquila Southwest Pipeline Corporation	$41,900	38%
	GPM Gas Corporation	$28,700	26%
	Wickford Energy Marketing, L.C.	$18,500	17%
1995	Aquila Southwest Pipeline Corporation	$18,548	33%
	Wickford Energy Marketing, L.C.	$15,704	28%
	GPM Gas Corporation	$11,686	21%
1994	Wickford Energy Marketing, L.C.	$ 6,190	28%
	GPM Gas Corporation	$ 6,105	27%
	Plains Marketing and Transportation, Inc.	$ 2,659	12%
	Texaco Exploration & Production, Inc.	$ 2,249	10%

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.

9. STOCKHOLDERS' EQUITY

On April 9, 1996, the company completed a public offering of 2,475,000 shares of Common Stock at a price of $35.33 per share, resulting in net proceeds (after offering costs) to the company of approximately $82.1 million. On April 12, 1996, the underwriters exercised an over-allotment option to purchase an additional 519,750 shares of Common Stock at a price of $35.33 per share, resulting in additional net proceeds (after offering costs) to the company of approximately $17.3 million. The net proceeds from the offering were used to fund a portion of the company's exploration and development capital expenditures and for general corporate purposes.

On March 31, 1994, the company issued 12% Senior Notes and Warrants for 2,190,937 shares of the company's Common Stock (see Note 2). The Warrants were valued at $3.04 million and are recorded as Common Stock Warrants and paid-in capital on the accompanying consolidated balance sheets. A portion of the 12% Senior Notes and Warrants were issued to Trust Company of the West in exchange for preferred stock, warrants to purchase Common Stock and an overriding royalty interest.

A 1.8-for-1 stock split of the Common Stock in January 1993, a 2-for-1 stock split of the Common Stock in December 1994, and 3-for-2 stock splits of the Common Stock in December 1995 and 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 1,881,000 shares. The maximum period for exercise of an option may not be more than ten years (or five years for an optionee who owns more than 10% of the Common Stock) from the date of grant, and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant (or 110% of such value for an optionee who owns more than 10% of the Common Stock). Options granted become exercisable at dates determined by the Stock Option Committee of the Board of Directors. No options may 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 1,566,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant, and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant. Options granted become exercisable at dates determined by the Stock Option Committee of the Board of Directors. No options may be granted under the NSO Plan after December 10, 2002.

Under the company's 1994 Stock Option Plan (the "1994 Plan"), incentive and nonqualified stock options to purchase Common Stock may be granted to employees of the company and its subsidiaries. Subject to any adjustment as provided by the 1994 Plan, the aggregate number of shares which may be issued and sold may not exceed 2,443,455 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant, and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant. Options granted become exercisable at dates determined by the Stock Option Committee of the Board of Directors. No options may be granted under the 1994 Plan after December 16, 2004.

	# Of Options	Option Prices
Options outstanding at June 30, 1993	885,780	$ 1.11 – $ 2.67
Options granted	1,640,250	$ 1.11 – $ 1.71
Options exercised	–	–
Options terminated	(9,360)	$ 1.11 – $ 1.33
Options outstanding at June 30, 1994	2,516,670	$ 1.11 – $ 2.67
Options granted	1,592,775	$ 4.50 – $ 9.84
Options exercised	(644,366)	$ 1.11 – $ 2.67
Options terminated	(50,783)	$ 1.11 – $ 4.50
Options outstanding at June 30, 1995	3,414,296	$ 1.11 – $ 9.84
Options granted	1,213,425	$11.33 – $35.33
Options exercised	(787,023)	$ 1.11 – $35.33
Options terminated	(39,256)	$ 1.11 – $11.33
Options outstanding at June 30, 1996	3,801,442	$ 1.11 – $35.33

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 fiscal 1996 and 1995, $7,950,000 and $1,229,000 was recorded as an adjustment 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 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 counter-parties and to basis risk.

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 swap arrangements that establish an index-related price above which the company pays the hedging partner and below which the company is paid by the hedging partner, the purchase of index-related puts that provide for a "floor" price to the company to be paid by the counter-party to the extent the price of the commodity is below the contracted floor, and basis protection swaps.

As of June 30, 1996, the company had established NYMEX-based crude oil swap agreements for 1,000 Bbl per day for July 1, 1996 through August 31, 1996 at an average price of $17.85 per Bbl. The counter-party has the option exercisable monthly for an additional 1,000 Bbl per day for the period July 1, 1996 through December 31, 1996 to cause a swap if the price exceeds an average $17.74 per Bbl. The actual settlements for July and August resulted in a $0.5 million payment to the counter-party. The company estimates, based on NYMEX prices as of August 30, 1996, that the effect of the September through December hedges would be a $0.4 million payment to the counter-party.

The company has purchased Houston Ship Channel put options which guarantee the company an average floor price of $2.21/Mmbtu for 20,000 Mmbtu per day for the period of November 1, 1996 through February 28, 1997. The average cost of these puts was $0.14 per Mmbtu.

As of June 30, 1996, the company had NYMEX-based natural gas swaps and NYMEX/Houston Ship Channel Basis swaps for the months of July through October 1996. These transactions resulted in payments to the company's counter-party of approximately $2 million for the month of July 1996 and $1.5 million for the month of August 1996. The company estimates, based on NYMEX prices as of August 30, 1996, that the effect of the September and October hedges would be a $0.2 million payment to the counter-party.

Concentration of Credit Risk

Financial instruments which potentially subject the company to concentrations of credit risk consist principally of 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 not considered investment grade, unless the credit risk can otherwise be mitigated.

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 June 30, 1996 and 1995 was $255.6 million and $135.2 million, respectively, compared to approximate fair values of $261.2 million and $137.8 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.

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:

June 30,	1996	1995
($ in thousands)		
Oil and gas properties:		
Proved	$ 363,213	$ 165,302
Unproved	165,441	27,474
Total	528,654	192,776
Less accumulated depreciation, depletion and amortization	(92,720)	(41,821)
Net capitalized costs	$ 435,934	$ 150,955

Unproved properties not subject to amortization at June 30, 1996 and 1995, consist mainly of lease acquisition costs. The company capitalized approximately $6,428,000 and $1,574,000 of interest during the years ended June 30, 1996 and 1995 on significant investments in unproved properties that are not being currently depreciated, depleted, or amortized and on which exploration or development activities are in progress. 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:

June 30,	1996	1995	1994
($ in thousands)			
Development costs	$143,437	$ 81,833	$ 26,277
Exploration costs	39,410	14,129	5,358
Acquisition costs:			
Unproved properties	138,188	24,437	3,305
Proved properties	24,560	–	–
Capitalized internal costs	1,699	586	965
Proceeds from sale of leasehold, equipment and other	(11,416)	(15,107)	(7,598)
Total	$335,878	$105,878	$ 28,307

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 the years ended June 30, 1996, 1995 and 1994, 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.

June 30,	1996	1995	1994
($ in thousands)			
Oil and gas sales	$110,849	$ 56,983	$ 22,404
Production costs (a)	(8,303)	(4,256)	(3,647)
Depletion and depreciation	(50,899)	(25,410)	(8,141)
Imputed income tax provision (b)	(18,335)	(9,561)	(3,610)
Results of operations from oil and gas producing activities	$ 33,312	$ 17,756	$ 7,006

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

(b) The imputed income tax provision is hypothetical and determined without regard to the company's deduction for general and administrative expenses, interest costs and other income tax credits and deductions.

Oil and Gas Reserve Quantities (unaudited)

The reserve information presented below is based upon reports prepared by the independent petroleum engineering firm of Williamson Petroleum Consultants, Inc. ("Williamson") as of June 30, 1996, 1995 and 1994 and the company's petroleum engineers as of June 30, 1996 and 1995. The reserves evaluated internally by the company constituted approximately 0.6% and 0.5% of total proved reserves as of June 30, 1996 and 1995, respectively. 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, as future information becomes available.

Proved oil and gas reserves represent the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods.

Presented below is a summary of changes in estimated reserves of the company based upon the reports prepared by Williamson for 1996, 1995 and 1994, along with those prepared by the company's petroleum engineers for 1996 and 1995:

June 30,	1996		1995		1994	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved reserves, beginning of year	5,116	211,808	4,154	117,066	9,622	79,763
Extensions, discoveries and other additions	8,924	173,577	2,345	129,444	2,335	82,965
Revisions of previous estimate	(812)	(2,538)	(244)	(9,588)	(868)	(5,523)
Production	(1,413)	(51,710)	(1,139)	(25,114)	(537)	(6,927)
Sale of reserves-in-place	–	–	–	–	(6,398)	(33,212)
Purchase of reserves-in-place	443	20,087	–	–	–	–
Proved reserves, end of year	12,258	351,224	5,116	211,808	4,154	117,066
Proved developed reserves, end of year	3,648	144,721	1,973	77,764	1,313	30,445

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 $35 million, subject to adjustment for activity after the effective date of January 1, 1996. The properties are located in the Knox and Golden Trend fields of southern Oklahoma, most of which are operated by the company.

In October 1993, the company entered into a joint development agreement covering a 20,000 gross acre development area in the Fayette County portion of the Giddings Field in southern Texas. The company's ownership interests in the proved undeveloped properties covered by the joint development agreement were significantly less than those used in the June 30, 1993 reserve report. The impact of the reduced ownership percentages is reflected as sales of reserves in place in fiscal 1994 in the preceding table.

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 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:

June 30,	1996	1995	1994
($ in thousands)			
Future cash inflows	$1,101,642	$427,377	$307,600
Future production costs	(168,974)	(75,927)	(50,765)
Future development costs	(137,068)	(76,543)	(47,040)
Future income tax provision	(173,439)	(46,537)	(36,847)
Future net cash flows	622,161	228,370	172,948
Less effect of a 10% discount factor	(171,973)	(69,359)	(54,340)
Standardized measure of discounted future net cash flows	$ 450,188	$159,011	$118,608

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

June 30,	1996	1995	1994
($ in thousands)			
Standardized measure, beginning of year	$ 159,011	$ 118,608	$ 119,744
Sales of oil and gas produced, net of production costs	(102,546)	(52,727)	(18,757)
Net changes in prices and production costs	87,736	(25,574)	(10,795)
Extensions and discoveries, net of production and development costs	292,255	93,969	99,175
Changes in future development costs	(11,201)	3,406	(2,855)
Development costs incurred during the period that reduced future development costs	43,409	23,678	9,855
Revisions of previous quantity estimates	(10,505)	(11,204)	(13,107)
Purchase of undeveloped reserves-in-place	29,641	–	–
Sales of reserves in-place	–	–	(66,372)
Accretion of discount	18,814	14,126	14,166
Net change in income taxes	(67,705)	(6,486)	(720)
Changes in production rates and other	11,279	1,215	(11,726)
Standardized measure, end of year	$ 450,188	$ 159,011	$ 118,608

12. QUARTERLY FINANCIAL DATA (unaudited)

Summarized unaudited quarterly financial data for fiscal 1996 and 1995 are as follows ($ in thousands except per share data):

	Quarter Ended			
	September 30, 1995	December 31, 1995	March 31, 1996	June 30, 1996
Net sales	$ 21,988	$ 31,766	$ 44,145	$ 47,692
Gross profit (a)	6,368	11,368	14,741	13,580
Net income	2,915	5,459	7,623	7,358
Net income per share:				
Primary	.10	.19	.26	.23
Fully-diluted	.10	.19	.26	.23

	Quarter Ended			
	September 30, 1994	December 31, 1994	March 31, 1995	June 30, 1995
Net sales	$ 13,042	$ 14,186	$ 15,788	$ 22,803
Gross profit (a)	4,559	5,805	4,997	7,702
Net income	2,336	3,248	2,305	3,772
Net income per share:				
Primary	.09	.12	.08	.13
Fully-diluted	.09	.12	.08	.13

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

CHESAPEAKE ENERGY CORPORATION

Annual Report Evaluation and Information Request Card

We would appreciate your feedback about our Annual Report.

How would you rate our communication on the following:	excellent	satisfactory	unsatisfactory
1) Chesapeake's strategy for continued growth	1	2	3
2) Chesapeake's competitive advantages	1	2	3
3) Chesapeake's operational expertise	1	2	3
4) Chesapeake's track record	1	2	3
5) Annual Report presentation	1	2	3

Comments/suggestions:

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Corporate Information

Stock Data	High	Low	Last
Fiscal 1994		*(in $)*	
First Quarter	2.61	1.42	1.42
Second Quarter	1.72	1.03	1.06
Third Quarter	1.50	1.06	1.39
Fourth Quarter	2.00	1.11	1.72
Fiscal 1995			
First Quarter	4.78	1.72	4.72
Second Quarter	7.33	4.27	7.00
Third Quarter	9.67	4.44	9.44
Fourth Quarter	13.17	9.33	11.44
Fiscal 1996			
First Quarter	14.44	9.06	14.06
Second Quarter	22.17	12.55	22.17
Third Quarter	33.00	21.58	30.83
Fourth Quarter	59.92	32.08	59.92
Fiscal 1997			
First Quarter	70.25	41.00	62.63

Common Stock

Chesapeake Energy Corporation's common stock is listed on the New York Stock Exchange under the symbol CHK. As of September 30, 1996, there were approximately 7,815 beneficial owners of common stock.

Dividends

The company's policy is to retain earnings to support the growth of the company. Chesapeake's Board of Directors has not authorized the payment of cash dividends on its common stock.

Form 10-K

Stockholders may obtain a copy of Chesapeake Energy Corporation's Form 10-K as filed with the Securities and Exchange Commission by contacting Thomas S. Price, Jr. at the address of the corporate office above or by calling (405) 848-8000, extension 257.

Corporate Headquarters

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

Independent Public Accountants

Coopers & Lybrand L.L.P.
15 North Robinson, Suite 400
Oklahoma City,
Oklahoma 73102
(405) 272-9251

Stock Transfer Agent and Registrar

Liberty Bank and Trust
Company of Oklahoma City
100 North Broadway Avenue
Oklahoma City,
Oklahoma 73102
(405) 231-6764

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", "anticipate", "expect", "believes", "goals", "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, volatility of oil and gas prices, the need to develop and replace its reserves, the substantial capital expenditures required to fund its operations, environmental risks, drilling and operating risks, risks related to exploration and development drilling outcomes, uncertainties about estimates of reserves, competition, government regulation, and the ability of the company to implement its business strategy.

DESIGN BY Aspen Marketing + Design LLC; Aspen, Colorado

CHESAPEAKE ENERGY CORPORATION
6100 North Western Avenue
Oklahoma City, Oklahoma 73118