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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2006

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

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

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

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $.01	New York Stock Exchange
7.5% Senior Notes due 2013	New York Stock Exchange
7.625% Senior Notes due 2013	New York Stock Exchange
7.0% Senior Notes due 2014	New York Stock Exchange
7.5% Senior Notes due 2014	New York Stock Exchange
6.375% Senior Notes due 2015	New York Stock Exchange
7.75% Senior Notes due 2015	New York Stock Exchange
6.625% Senior Notes due 2016	New York Stock Exchange
6.875% Senior Notes due 2016	New York Stock Exchange
6.5% Senior Notes due 2017	New York Stock Exchange
6.25% Senior Notes due 2018	New York Stock Exchange
6.875% Senior Notes due 2020	New York Stock Exchange
2.75% Contingent Convertible Senior Notes due 2035	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	New York Stock Exchange
6.25% Mandatory Convertible Preferred Stock	New York Stock Exchange

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☒ NO ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. YES ☐ NO ☒

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ☐ NO ☒

The aggregate market value of our common stock held by non-affiliates on June 30, 2006 was approximately $11.9 billion. At February 23, 2007, there were 460,068,149 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2007 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

2006 ANNUAL REPORT ON FORM 10-K

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PART I

ITEM 1. *Business*

General

We are the third largest independent producer of natural gas in the United States, and we own interests in approximately 34,600 producing oil and natural gas wells that are currently producing approximately 1.7 billion cubic feet equivalent, or bcfe, per day, 92% of which is natural gas. Our strategy is focused on discovering, developing and acquiring conventional and unconventional natural gas reserves onshore in the U.S. east of the Rocky Mountains. Our operations are located in the *Mid-Continent region*, which includes Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle; the *Forth Worth Basin* in north-central Texas; the *Appalachian Basin*, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York; the *Permian and Delaware Basins* of West Texas and eastern New Mexico; the *Ark-La-Tex* area of East Texas and northern Louisiana; and the *South Texas and Texas Gulf Coast regions*. We have established a top-three position in nearly every major shale play in the U.S., including the Fort Worth Basin Barnett Shale, the Arkansas Fayetteville Shale, the Appalachian Basin Devonian Shale, the southeast Oklahoma Woodford Shale, the Delaware Basin Barnett and Woodford Shales, the Illinois Basin New Albany Shale and the Conasauga, Floyd and Chattanooga Shales in Alabama.

As of December 31, 2006, we had 9.0 trillion cubic feet equivalent, or tcfe, of proved reserves, of which 93% were natural gas and all of which were onshore. During 2006, we produced an average of 1.585 bcfe per day, a 23% increase over the 1.284 bcfe per day produced in 2005. We replaced our 578 bcfe of production with an internally estimated 2.013 tcfe of new proved reserves for a reserve replacement rate of 348%. Reserve replacement through the drillbit was 1.345 tcfe, or 233% of production (including 729 bcfe of positive performance revisions and 212 bcfe of downward revisions resulting from natural gas price declines), and reserve replacement through acquisitions was 668 bcfe, or 115% of production. As a result, our proved reserves grew by 19% during 2006, from 7.5 tcfe to 9.0 tcfe. Of our 9.0 tcfe of proved reserves, 62% were proved developed reserves.

During 2006, we led the nation in drilling activity with an average utilization of 98 operated rigs and 79 non-operated rigs. Through this drilling activity, we drilled 1,488 (1,243 net) operated wells and participated in another 1,534 (206 net) wells operated by other companies. Our success rate was 99% for operated wells and 98% for non-operated wells. In 2006, we added approximately 2,000 new employees to support our growth, which increased our total employee base to approximately 4,900 employees at December 31, 2006, and invested $771 million in leasehold (excluding leasehold acquired through corporate and asset acquisitions) and 3-D seismic data, all of which we consider the building blocks of future value creation.

From January 1, 1998 through December 31, 2006, we were one of the most active consolidators of onshore U.S. natural gas assets, having purchased approximately 6.5 tcfe of proved reserves, at a total cost of approximately $14.3 billion (including $5.1 billion for unproved leasehold, but excluding $989 million of deferred taxes established in connection with certain corporate acquisitions). Excluding the amounts allocated to unproved leasehold and deferred taxes, our acquisition cost per proved thousand cubic feet equivalent, or mcfe, was $1.41 over this time period. During 2006, we remained active in the acquisitions market. Acquisition expenditures in 2006 totaled $4.0 billion (including $2.9 billion for unproved leasehold, but excluding $180 million of deferred taxes established in connection with certain corporate acquisitions).

Our principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118 and our main telephone number at that location is (405) 848-8000. We make available free of charge on our website at *www.chkenergy.com* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. References to “us”, “we” and “our” in this report refer to Chesapeake Energy Corporation together with its subsidiaries.

Business Strategy

Since our inception in 1989, Chesapeake’s goal has been to create value for investors by building one of the largest onshore natural gas resource bases in the United States. For the past nine years, our strategy to accomplish this goal has been to focus onshore in the U.S. east of the Rockies where the company believes it can generate attractive risk adjusted returns. In building our industry-leading resource base, we have integrated an aggressive and technologically-advanced drilling program with an active property consolidation program focused on small to medium-sized corporate and property acquisitions. To date, we have built leading positions in the Mid-Continent region, the Fort Worth Barnett Shale in North Texas, the South Texas and Texas Gulf Coast regions, the Permian and Delaware Basins of West Texas and eastern New Mexico, the Fayetteville Shale in Arkansas, the Ark-La-Tex area of East Texas and northern Louisiana, the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York, the Caney and Woodford Shales in southeastern Oklahoma, the Barnett and Woodford Shales in west Texas and the Conasauga, Floyd and Chattanooga Shales of Alabama.

Key elements of this business strategy are further explained below:

Grow through the Drillbit. One of our most distinctive characteristics is our ability to increase reserves and production through the drillbit. We are currently utilizing approximately 132 operated drilling rigs and approximately 90 non-operated drilling rigs to conduct the most active drilling program in the U.S. We focus both on finding significant new natural gas reserves and developing existing proved reserves, principally at deeper depths than the industry average. For the past nine years, we have been actively investing in leasehold, 3-D seismic information and human capital to be able to take advantage of the favorable drilling economics that exist today. While we believe U.S. natural gas production has declined during the past six years, we are one of the few large-cap independent oil and natural gas companies that have been able to increase production, which we have successfully achieved for the past 17 consecutive years and 22 consecutive quarters. We believe key elements of the success and scale of our drilling programs have been our early recognition that natural gas prices were likely to move higher in the U.S. in the post-2000 period accompanied by our willingness to proactively hire new employees and to build the nation's largest onshore leasehold and 3-D seismic inventories, all of which are the building blocks of a successful large-scale drilling program.

Make High-Quality Acquisitions. Our acquisition program is focused on acquisitions of natural gas properties that offer high-quality, long-lived production and significant development and higher potential deep drilling opportunities. From January 1, 1998 through December 31, 2006, we purchased approximately 6.5 tcfe of proved reserves, at a total cost of approximately $14.3 billion (including $5.1 billion for unproved leasehold, but excluding $989 million of deferred taxes established in connection with certain corporate acquisitions). Excluding the amounts allocated to unproved leasehold and deferred taxes, our acquisition cost per proved mcfe was $1.41 over this time period. The majority of these acquisitions either increased our ownership in existing wells or fields or added additional drilling locations in our focused operating areas. Because these operating areas contain many smaller companies seeking liquidity opportunities and larger companies seeking to divest non-core assets, we expect to continue to find additional attractive acquisition opportunities in the future.

Focus on Low Costs. By minimizing lease operating costs and general and administrative expense through focused activities and increased scale, we have been able to deliver attractive financial returns through all phases of the commodity price cycle. We believe our low cost structure is the result of management's effective cost-control programs, a high-quality asset base and extensive and competitive services, natural gas processing and transportation infrastructures that exist in our key operating areas. In addition, to control costs and service quality we have made significant investments in our drilling rig and trucking service operations and in our midstream gathering and compression operations. As of December 31, 2006, we operated approximately 20,400 of our 34,600 wells, which delivered approximately 83% of our daily production volume. This large percentage of operated properties provides us with a high degree of operating flexibility and cost control.

Build Regional Scale. We believe one of the keys to success in the natural gas exploration industry is to build significant operating scale in a limited number of operating areas that share many similar geological and operational characteristics. Achieving such scale provides many benefits, the most important of which are higher per unit revenues, lower per unit operating costs, greater rates of drilling success, higher returns from more easily integrated acquisitions and higher returns on drilling investments. We first began pursuing this focused strategy in the Mid-Continent region in late 1997 and we are now the largest natural gas producer, the most active driller and the most active acquirer of leasehold and producing properties in the Mid-Continent. We believe this region, which trails only the Gulf Coast and Rocky Mountains in current U.S. natural gas production, has many attractive characteristics. These characteristics include long-lived natural gas properties with predictable decline curves, multi-pay geological targets that decrease drilling risk and have resulted in a drilling success rate of 97% over the past 17 years, generally lower service costs than in more competitive or more remote basins and a favorable regulatory environment with virtually no federal land ownership. We believe the other areas where we operate possess many of these same favorable characteristics and our goal is to become or remain a top three natural gas producer in each of our operating areas.

Improve our Balance Sheet. We have made significant progress in improving our balance sheet over the past eight years. From December 31, 1998 through December 31, 2006, we increased our stockholders' equity by $11.5 billion through a combination of earnings and common and preferred equity issuances. As of December 31, 2006, our debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders' equity) was 40%, compared to 47% as of December 31, 2005 and 137% as of December 31, 1998. We believe our business strategy and operational performance will lead to an investment grade credit rating for our unsecured debt in the future.

Based on our view that natural gas will be in a tight supply/demand relationship in the U.S. during at least the next few years because of the significant structural challenges to growing natural gas supply and the growing demand for this clean-burning, domestically produced fuel, we believe our focused natural gas acquisition, exploitation and exploration strategy should provide substantial value-creating growth opportunities in the years ahead. Our goal is to increase our overall production by 14% to 18% in 2007 and 10% to 14% in 2008.

Company Strengths

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

High-Quality Asset Base. Our producing properties are characterized by long-lived reserves, established production profiles and an emphasis on onshore natural gas. Based upon current production and proved reserve estimates, our proved reserves-to-production ratio, or reserve life, is approximately 14.5 years. In addition, we believe we are the seventh largest producer of natural gas in the U.S. (third among independents) and the fifth largest owner of proved U.S. natural gas reserves (second among independents). In each of our operating areas, our properties are concentrated in locations that enable us to establish substantial economies of scale in drilling and production operations and facilitate the application of more effective reservoir management practices. We intend to continue building our asset base in each of our operating areas through a balance of acquisitions, exploitation and exploration.

Large Inventory of Drilling Projects. During the 17 years since our inception, we have been among the five most active drillers of new wells in the U.S. Presently, we are the most active driller in the U.S. with 132 operated and 90 non-operated rigs drilling. Through this high level of activity over the years, we have developed an industry-leading expertise in drilling deep vertical and horizontal wells in search of large natural gas accumulations in challenging conventional and unconventional reservoirs. As a result of our successful acquisition program and active leasehold acquisition and seismic acquisition strategies, we have been able to accumulate a U.S. onshore leasehold position of approximately 10.4 million net acres, and have acquired rights to 16.3 million acres of onshore 3-D seismic data to provide informational advantages over our competitors and to help evaluate our large acreage inventory. On this very large acreage position, our technical teams believe we have approximately 26,000 net exploratory and developmental drilling locations, representing a backlog of approximately 10 years of future drilling opportunities at current drilling rates.

Successful Acquisition Program. Our experienced acquisition team focuses on enhancing and expanding our existing assets in each of our operating areas. These areas are characterized by long-lived natural gas reserves, low lifting costs, multiple geological targets, generally favorable basis differentials to benchmark commodity prices, well-developed oil and natural gas transportation infrastructures and considerable potential for further consolidation of assets. Since 1998, we have acquired approximately 6.5 tcfe of proved reserves that replaced 270% of our total production. We believe we are well-positioned to continue making attractive acquisitions as a result of our extensive track record of identifying, completing and integrating multiple successful acquisitions, our large operating scale and our knowledge and experience in the regions in which we operate.

Low-Cost Producer. Our high-quality asset base, the work ethic of our employees, our hands-on management style and our headquarters location in Oklahoma City have enabled us to achieve a low operating and administrative cost structure. During 2006, our operating costs per unit of production were $1.40 per mcfe, which consisted of general and administrative expenses of $0.24 per mcfe (including non-cash stock-based compensation of $0.05 per mcfe), production expenses of $0.85 per mcfe and production taxes of $0.31 per mcfe. We believe this is one of the lowest cost structures among publicly-traded, large-cap independent oil and natural gas producers.

Effective Hedging Program. We have used and intend to continue using hedging programs to reduce the risks inherent in acquiring and producing oil and natural gas reserves, commodities that are frequently characterized by significant price volatility. We believe this price volatility is likely to continue in the years ahead and that we can use this volatility to our benefit by taking advantage of prices when they reach levels that management believes are either unsustainable for the long-term or provide unusually high rates of return on our invested capital. We currently have natural gas swaps in place covering 48% and 60% of our anticipated natural gas production for 2007 and 2008, respectively, at average NYMEX prices of $8.63 and $9.20 per mcf, respectively, along with natural gas collars covering 10% of our anticipated natural gas production for 2007 with an average NYMEX floor of $6.88 per mcf and an average NYMEX ceiling of $8.41 per mcf. Additionally, we have written call options covering 10% and 13% of our 2007 and 2008 natural gas production, respectively, at a weighted average price of $9.56 and $10.20 per mcf, respectively. We have oil swaps in place covering 59% and 51% of our anticipated oil production for 2007 and 2008, respectively, at average NYMEX prices of $71.90 and $71.63 per barrel of oil, respectively. During 2006, we realized gains from our hedging program of approximately $1.254 billion, which increased our realized price per mcfe by $2.17.

Entrepreneurial Management. Our management team formed the company in 1989 with an initial capitalization of $50,000 and fewer than ten employees. Since then, our management team has guided the company through various operational and industry challenges and extremes of oil and natural gas prices to create the third largest independent producer of natural gas in the U.S. with approximately 4,900 employees and an enterprise value of approximately $23.8 billion. Our chief executive officer and co-founder, Aubrey K. McClendon, has been in the oil and natural gas industry for 25 years and beneficially owns, as of February 23, 2007, approximately 25.8 million shares of our common stock.

Properties

Chesapeake focuses its natural gas exploration, development and acquisition efforts in six operating areas: (i) the Mid-Continent, representing 47% of our proved reserves, (ii) the Fort Worth Basin, representing 13% of our proved reserves , (iii) the Appalachian Basin, representing 17% of our proved reserves, (iv) the Permian and Delaware Basins, representing 8% of our proved reserves, (v) the Ark-La-Tex area, representing 8% of our proved reserves, and (vi) the South Texas and Texas Gulf Coast regions, representing 7% of our proved reserves.

Chesapeake's strategy for 2007 is to continue developing our natural gas assets through exploratory and developmental drilling and by selectively acquiring strategic properties in the Mid-Continent and in our secondary areas. We project that our 2007 production will be between 665 bcfe and 675 bcfe. We have budgeted $4.7 billion to $4.9 billion for drilling, acreage acquisition, seismic and related capitalized internal costs, all of which is expected to be funded with operating cash flow based on our current assumptions and borrowings under our revolving bank credit facility. Our budget is frequently adjusted based on changes in oil and natural gas prices, drilling results, drilling costs and other factors. We expect to fund future acquisitions through a combination of operating cash flow, our revolving bank credit facility and, if needed, new debt and equity issuances.

Operating Areas

Mid-Continent. Chesapeake's Mid-Continent proved reserves of 4.226 tcfe represented 47% of our total proved reserves as of December 31, 2006, and this area produced 315 bcfe, or 55%, of our 2006 production. During 2006, we invested approximately $1.530 billion to drill 1,884 (621 net) wells in the Mid-Continent. For 2007, we anticipate spending approximately 37% of our total budget for exploration and development activities in the Mid-Continent region.

Fort Worth Barnett Shale. Chesapeake's Fort Worth Barnett Shale proved reserves represented 1.141 tcfe, or 13%, of our total proved reserves as of December 31, 2006. During 2006, the Fort Worth Barnett Shale assets produced 44 bcfe, or 7%, of our total production. During 2006, we invested approximately $428 million to drill 244 (187 net) wells in the Fort Worth Barnett Shale. For 2007, we anticipate spending approximately 26% of our total budget for exploration and development activities in the Fort Worth Barnett Shale.

Appalachian Basin. Chesapeake's Appalachian Basin proved reserves represented 1.491 tcfe, or 17%, of our total proved reserves as of December 31, 2006. During 2006, the Appalachian assets produced 45 bcfe, or 8%, of our total production. During 2006, we invested approximately $171 million to drill 319 (272 net) wells in the Appalachian Basin. For 2007, we anticipate spending approximately 7% of our total budget for exploration and development activities in the Appalachian Basin.

Permian and Delaware Basins. Chesapeake's Permian and Delaware Basins proved reserves represented 725 bcfe, or 8%, of our total proved reserves as of December 31, 2006. During 2006, the Permian assets produced 49 bcfe, or 8%, of our total production. During 2006, we invested approximately $413 million to drill 189 (92 net) wells in the Permian and Delaware Basins. For 2007, we anticipate spending approximately 13% of our total budget for exploration and development activities in the Permian and Delaware Basins.

Ark-La-Tex. Chesapeake's Ark-La-Tex proved reserves represented 711 bcfe, or 8%, of our total proved reserves as of December 31, 2006. During 2006, the Ark-La-Tex assets produced 46 bcfe, or 8%, of our total production. During 2006, we invested approximately $381 million to drill 248 (175 net) wells in the Ark-La-Tex region. For 2007, we anticipate spending approximately 9% of our total budget for exploration and development activities in the Ark-La-Tex area.

South Texas and Texas Gulf Coast. Chesapeake's South Texas and Texas Gulf Coast proved reserves represented 661 bcfe, or 7%, of our total proved reserves as of December 31, 2006. During 2006, the South Texas and Texas Gulf Coast assets produced 79 bcfe, or 14%, of our total production. For 2006, we invested approximately $375 million to drill 138 (102 net) wells in the South Texas and Texas Gulf Coast regions. For 2007, we anticipate spending approximately 8% of our total budget for exploration and development activities in the South Texas and Texas Gulf Coast regions.

Drilling Activity

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

	2006				2005				2004			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Development:												
Productive	2,844	98%	1,364	99%	1,736	97%	735	97%	1,239	97%	463	98%
Non-productive	47	2	13	1	51	3	21	3	34	3	9	2
Total	2,891	100%	1,377	100%	1,787	100%	756	100%	1,273	100%	472	100%
Exploratory:												
Productive	128	98%	71	99%	177	98%	57	95%	164	92%	67	91%
Non-productive	3	2	1	1	4	2	3	5	14	8	7	9
Total	131	100%	72	100%	181	100%	60	100%	178	100%	74	100%

The following table shows the wells we drilled by area:

	2006		2005		2004	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Mid-Continent	1,884	621	1,442	498	1,195	417
Fort Worth Barnett Shale	244	187	—	—	—	—
Appalachian Basin	319	272	15	11	—	—
Permian and Delaware Basins	189	92	139	56	107	55
Ark-La-Tex	248	175	257	171	82	36
South Texas and Texas Gulf Coast	138	102	115	80	67	38
Total	3,022	1,449	1,968	816	1,451	546

At December 31, 2006, we had 270 (128 net) wells in process.

Well Data

At December 31, 2006, we had interests in approximately 34,600 (19,079 net) producing wells, including properties in which we held an overriding royalty interest, of which 6,500 (3,608 net) were classified as primarily oil producing wells and 28,100 (15,471 net) were classified as primarily natural gas producing wells. Chesapeake operates approximately 20,400 of its 34,600 producing wells. During 2006, we drilled 1,488 (1,243 net) wells and participated in another 1,534 (206 net) wells operated by other companies. We operate approximately 83% of our current daily production volumes.

Production, Sales, Prices and Expenses

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

	Years Ended December 31,		
	2006	2005	2004
Net Production:			
Oil (mbbls)	8,654	7,698	6,764
Natural gas (mmcf)	526,459	422,389	322,009
Natural gas equivalent (mmcfe)	578,383	468,577	362,593
Oil and Natural Gas Sales ($ in thousands):			
Oil sales	$ 526,687	$ 401,845	$ 260,915
Oil derivatives – realized gains (losses)	(14,875)	(34,132)	(69,267)
Oil derivatives – unrealized gains (losses)	28,459	4,374	3,454
Total oil sales	$ 540,271	$ 372,087	$ 195,102
Natural gas sales	$ 3,343,056	$ 3,231,286	$ 1,789,275
Natural gas derivatives – realized gains (losses)	1,268,528	(367,551)	(85,634)
Natural gas derivatives – unrealized gains (losses)	467,039	36,763	37,433
Total natural gas sales	$ 5,078,623	$ 2,900,498	$ 1,741,074
Total oil and natural gas sales	$ 5,618,894	$ 3,272,585	$ 1,936,176
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 60.86	$ 52.20	$ 38.57
Natural gas ($ per mcf)	$ 6.35	$ 7.65	$ 5.56
Natural gas equivalent ($ per mcfe)	$ 6.69	$ 7.75	$ 5.65
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 59.14	$ 47.77	$ 28.33
Natural gas ($ per mcf)	$ 8.76	$ 6.78	$ 5.29
Natural gas equivalent ($ per mcfe)	$ 8.86	$ 6.90	$ 5.23
Other Operating Income ($ per mcfe):			
Oil and natural gas marketing	$ 0.09	$ 0.07	$ 0.05
Service operations	$ 0.11	$ —	$ —
Expenses ($ per mcfe):			
Production expenses	$ 0.85	$ 0.68	$ 0.56
Production taxes	$ 0.31	$ 0.44	$ 0.29
General and administrative expenses	$ 0.24	$ 0.14	$ 0.10
Oil and natural gas depreciation, depletion and amortization	$ 2.35	$ 1.91	$ 1.61
Depreciation and amortization of other assets	$ 0.18	$ 0.11	$ 0.08
Interest expense[(a)]	$ 0.52	$ 0.47	$ 0.45

(a) Includes the effects of realized gains or (losses) from interest rate derivatives, but does not include the effects of unrealized gains or (losses) and is net of amounts capitalized.

Oil and Natural Gas Reserves

The tables below set forth information as of December 31, 2006 with respect to our estimated proved reserves, the associated estimated future net revenue and present value (discounted at an annual rate of 10%) of estimated future net revenue before and after income tax (standardized measure) at such date. Neither the pre-tax present value of estimated future net revenue nor the after-tax standardized measure is intended to represent the current market value of the estimated oil and natural gas reserves we own.

	December 31, 2006		
	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
Proved developed	76,705	5,113,211	5,573,441
Proved undeveloped	29,325	3,206,223	3,382,173
Total proved	106,030	8,319,434	8,955,614

	Proved Developed	Proved Undeveloped	Total Proved
		($ in thousands)	
Estimated future net revenue[a]	$ 22,164,254	$ 8,225,842	$ 30,390,096
Present value of estimated future net revenue [a]	$ 11,292,561	$ 2,354,580	$ 13,647,141
Standardized measure [a] [b]			$ 10,006,571

	Oil (mbbl)	Gas (mmcf)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value ($ in thousands)
Mid-Continent	52,432	3,911,275	4,225,867	47%	$ 6,948,701
Fort Worth Barnett Shale	91	1,140,833	1,141,379	13	1,310,275
Appalachian Basin	957	1,485,446	1,491,188	17	1,652,134
Permian and Delaware Basins	42,284	471,452	725,156	8	1,495,751
Ark-La-Tex	5,661	677,473	711,439	8	819,272
South Texas and Texas Gulf Coast	4,605	632,955	660,585	7	1,421,008
Total	106,030	8,319,434	8,955,614	100%	$ 13,647,141[a]

(a) Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at December 31, 2006. The prices used in our external and internal reserve reports yield weighted average wellhead prices of $56.25 per barrel of oil and $5.41 per mcf of natural gas. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity hedges in place at December 31, 2006. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. Estimated future net revenue and the present value thereof differ from future net cash flows and the standardized measure thereof only because the former do not include the effects of estimated future income tax expenses ($3.64 billion as of December 31, 2006).

Management uses future net revenue, which is calculated without deducting estimated future income tax expenses, and the present value thereof as one measure of the value of the company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We also understand that securities analysts and rating agencies use this measure in similar ways. While future net revenue and present value are based on prices, costs and discount factors which are consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company.

(b) The standardized measure of discounted future net cash flows is calculated in accordance with SFAS 69. Additional information on the standardized measure is presented in Note 11 of the notes to our consolidated financial statements included in Item 8 of this report.

As of December 31, 2006, our reserve estimates included 3.382 tcfe of reserves classified as proved undeveloped (PUD). Of this amount, approximately 40%, 34% and 16% (by volume) were initially classified as PUDs in 2006, 2005 and 2004, respectively, and the remaining 10% were initially classified as PUDs prior to 2004. Of our proved developed reserves, 655 bcfe are non-producing, which are primarily “behind pipe” zones in producing wells.

The future net revenue attributable to our estimated proved undeveloped reserves of $8.2 billion at December 31, 2006, and the $2.4 billion present value thereof, have been calculated assuming that we will expend approximately $6.2 billion to develop these reserves. We have projected to incur $2.7 billion in 2007, $1.4 billion in 2008, $0.8 billion in 2009 and $1.3 billion in 2010 and beyond, although the amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, product prices and the availability of capital. We do not believe any of these proved undeveloped reserves are contingent upon installation of additional infrastructure and we are not subject to regulatory approval other than routine permits to drill, which we expect to obtain in the normal course of business.

Chesapeake employed third-party engineers to prepare independent reserve forecasts for approximately 80% of our proved reserves (by volume) at year-end 2006. These are not audits or reviews of internally prepared reserve reports. The estimates of the proved reserves evaluated by third-party engineers were within 99% of the company’s own estimates and were used instead of our estimates for booking purposes. Netherland, Sewell & Associates, Inc. evaluated 32%, Data and Consulting Services, Division of Schlumberger Technology Corporation evaluated 16%, Lee Keeling and Associates, Inc. evaluated 14%, Ryder Scott Company L.P. evaluated 10% and LaRoche Petroleum Consultants, Ltd. evaluated 8% of our estimated proved reserves by volume at December 31, 2006. The estimates prepared by the independent firms covered approximately 18,000 properties, or 40% of the 45,000 properties included in the 2006 reserve reports. Because, in management’s opinion, it would be cost prohibitive for third-party engineers to evaluate all of our wells, we have prepared internal reserve forecasts for approximately 20% of our proved reserves. All estimates were prepared based upon a review of production histories and other geologic, economic, ownership and engineering data we developed. The estimates are not based on any single significant assumption due to the diverse nature of the reserves and there is no significant concentration of proved reserves volume or value in any one well or field.

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

Chesapeake's ownership interest used in calculating proved reserves and the associated estimated future net revenue was determined after giving effect to the assumed maximum participation by other parties to our farmout and participation agreements. The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for oil and natural gas production sold subsequent to December 31, 2006. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond Chesapeake's control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates, and such revisions may be material. Accordingly, reserve estimates are often different from the actual quantities of oil and natural gas that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate. A change in price of $0.10 per mcf for natural gas and $1.00 per barrel for oil would result in a change in the December 31, 2006 present value of estimated future net revenue of our proved reserves of approximately $350 million and $50 million, respectively. The estimated future net revenue used in this analysis does not include the effects of future income taxes or hedging. The foregoing uncertainties are particularly true as to proved undeveloped reserves, which are inherently less certain than proved developed reserves and which comprise a significant portion of our proved reserves.

The company's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2006, 2005 and 2004, and the changes in quantities and standardized measure of such reserves for each of the three years then ended, are shown in Note 11 of the notes to the consolidated financial statements included in Item 8 of this report.

Development, Exploration, Acquisition and Divestiture Activities

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

	December 31,		
	2006	**2005**	**2004**
		($ in thousands)	
Acquisition costs:			
Proved properties	$ 1,175,616	$3,554,651	$1,541,920
Unproved properties	2,855,848	1,375,675	570,495
Deferred income taxes	179,731	251,722	463,949
Total	4,211,195	5,182,048	2,576,364
Development costs:			
Development drilling [(a)]	2,772,149	1,566,730	863,268
Leasehold acquisition	616,550	290,946	110,530
Asset retirement obligation and other	23,214	52,619	41,924
Total	3,411,913	1,910,295	1,015,722
Exploration costs:			
Exploratory drilling	348,703	253,341	128,635
Geological and geophysical [(b)]	153,993	70,901	55,618
Total	502,696	324,242	184,253
Sales of oil and natural gas properties	(118)	(9,769)	(12,048)
Total	$ 8,125,686	$7,406,816	$3,764,291

(a) Includes capitalized internal cost of $147.3 million, $94.1 million and $45.4 million, respectively.
(b) Includes capitalized internal cost of $13.3 million, $8.1 million and $6.3 million, respectively.

Our development costs included $1.208 billion, $671 million and $333 million in 2006, 2005 and 2004, respectively, related to properties carried as proved undeveloped locations in the prior year's reserve reports. Included in our reserve reports as of December 31, 2006 are estimated future development costs of $6.2 billion related to the development of proved undeveloped reserves ($2.7 billion in 2007, $1.4 billion in 2008, $0.8 billion in 2009 and $1.3 billion in 2010 and beyond). Chesapeake's developmental drilling schedules are subject to revision and reprioritization throughout the year, resulting from unknowable factors such as the relative success in an individual developmental drilling prospect leading to an additional drilling opportunity, rig availability, title issues or delays, and the effect that acquisitions may have on prioritizing development drilling plans.

A summary of our exploration and development, acquisition and divestiture activities in 2006 by operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Leasehold	Acquisition of Unproved Properties	Acquisition of Proved Properties[a]	Sales of Properties	Total
					($ in thousands)			
Mid-Continent	1,884	621	$ 1,529,917	$ 325,733	$ 206,575	$ 223,642	$ (73)	$ 2,285,794
Fort Worth Barnett Shale	244	187	427,872	5,461	1,153,502	470,773	—	2,057,608
Appalachian Basin	319	272	171,241	19,611	175,197	21,134	—	387,183
Permian and Delaware Basins	189	92	413,296	44,551	659,144	10,814	(45)	1,127,760
Ark-La-Tex	248	175	380,514	53,697	319,738	55,106	—	809,055
South Texas and Texas Gulf Coast	138	102	375,219	167,497	341,692	573,878	—	1,458,286
Total	3,022	1,449	$ 3,298,059	$ 616,550	$ 2,855,848	$ 1,355,347	$ (118)	$ 8,125,686

(a) Includes $180 million of deferred tax adjustments.

Acreage

The following table sets forth as of December 31, 2006 the gross and net acres of both developed and undeveloped oil and natural gas leases which we hold. "Gross" acres are the total number of acres in which we own a working interest. "Net" acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our options to acquire additional leasehold which have not been exercised.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	3,739,724	1,793,900	4,488,205	2,268,007	8,227,929	4,061,907
Fort Worth Barnett Shale	58,706	50,329	189,847	131,346	248,553	181,675
Appalachian Basin	524,348	496,311	3,425,091	3,240,776	3,949,439	3,737,087
Permian and Delaware Basins	326,819	175,101	1,741,527	1,083,636	2,068,346	1,258,737
Ark-La-Tex	201,082	131,296	1,011,252	596,828	1,212,334	728,124
South Texas and Texas Gulf Coast	323,824	201,477	289,533	211,036	613,357	412,513
Total	5,174,503	2,848,414	11,145,455	7,531,629	16,319,958	10,380,043

Marketing

Chesapeake's oil production is generally sold under market sensitive or spot price contracts. The revenue we receive from the sale of natural gas liquids is included in oil sales. Our natural gas production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after transportation and processing of our natural gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. Under percentage-of-index contracts, the price per mmbtu we receive for our natural gas is tied to indexes published in *Inside FERC* or *Gas Daily*. Although exact percentages vary daily, as of February 2007, approximately 80% of our natural gas production was sold under short-term contracts at market-sensitive or spot prices.

During 2006, sales to Eagle Energy Partners I, L.P. (Eagle) of $867 million accounted for 16% of our total revenues (excluding gains (losses) on derivatives). Chesapeake owns approximately 33% of Eagle. Management believes that the loss of this customer would not have a material adverse effect on our results of operations or our financial position. No other customer accounted for more than 10% of total revenues (excluding gains (losses) on derivatives) in 2006.

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

Drilling

In 2001, Chesapeake formed its 100% owned drilling rig subsidiary, Nomac Drilling Corporation ("Nomac") with an investment of $26 million to build and refurbish five drilling rigs. As of December 31, 2006, Chesapeake had invested approximately $300 million to build or acquire 42 drilling rigs and to initiate the construction of 14 additional rigs. Including 24 rigs sold in 2006 and subsequently leased back to Chesapeake through 2014, the drilling rigs have depth ratings between 4,200 and 23,000 feet and range in drilling horsepower from 575 to 2,000. These drilling rigs are currently operating in Oklahoma, Texas and Appalachia. The company's drilling rig fleet should reach 81 rigs by mid-year 2007, which would rank Chesapeake as the sixth largest drilling rig contractor in the U.S. Additionally, the company has a $77 million investment in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake's equity ownership is approximately 45% and 49%, respectively. DHS owns 16 rigs and Mountain is operating 4 rigs and has another 4 rigs under construction or on order for delivery in 2007.

Natural Gas Gathering

Chesapeake owns and operates gathering systems in 13 states throughout the Mid-Continent and Appalachian regions. These systems are designed primarily to gather company production for delivery into major intrastate or interstate pipelines and are comprised of approximately 8,000 miles of gathering lines, treating facilities and processing facilities which provide service to approximately 9,750 wells.

Trucking

In 2006, Chesapeake expanded its service operations by acquiring two privately-owned oilfield trucking service companies. Our trucking business is utilized primarily to transport drilling rigs for both Chesapeake and third parties. As of December 31, 2006, our fleet includes 174 trucks which mainly service the Mid-Continent and Appalachian regions.

Compression

During the past few years Chesapeake has expanded its compression business. As of December 31, 2006, we operated 732 compressors, including wellhead and system compressors. Our compression business exists to facilitate the transportation of our natural gas production.

Hedging Activities

We utilize hedging strategies to hedge the price of a portion of our future oil and natural gas production and to manage interest rate exposure. See Item 7A-Quantitative and Qualitative Disclosures About Market Risk.

Regulation

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

Regulation of Oil and Natural Gas Operations. Our exploration and production operations are subject to various types of regulation at the U.S. federal, state and local levels, although very few of our oil and natural gas leases are located on federal lands. Such regulation includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to regulation are:

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

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

Chesapeake operates a number of natural gas gathering systems. The U.S. Department of Transportation and certain state agencies regulate the safety and operating aspects of the transportation and storage activities of these facilities. There is currently no price regulation of the company's sales of oil, natural gas liquids and natural gas, although, governmental agencies may elect in the future to regulate certain sales.

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

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

- air emissions,
- discharges into surface waters, and
- the construction and operation of underground injection wells or surface pits to dispose of produced saltwater and other nonhazardous oilfield wastes.

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

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

We have made and will continue to make expenditures to comply with environmental regulations and requirements. These are necessary business costs in the oil and natural gas industry. Although we are not fully insured against all environmental risks, we maintain insurance coverage which we believe is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental laws and regulations, as well as claims for damages to property or persons resulting from company operations, could result in substantial costs and liabilities, including civil and criminal penalties, to Chesapeake. We believe we are in compliance with existing environmental regulations, and that, absent the occurrence of an extraordinary event the effect of which cannot be predicted, any noncompliance will not have a material adverse effect on our operations or earnings.

Income Taxes

Chesapeake recorded income tax expense of $1.252 billion in 2006 compared to income tax expense of $545.1 million in 2005 and $289.8 million in 2004. Of the $706.9 million increase in 2006, $643.1 million was the result of the increase in net income before taxes and $63.8 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in 2006 compared to 36.5% in 2005 and 36% in 2004. The increase in 2006 reflected the impact state income taxes and permanent differences had on our overall effective rate along with the effect of a Texas tax law change. In May 2006, Texas eliminated the existing franchise tax and replaced it with a new income-based margin tax. The new tax is effective for tax returns due on or after January 1, 2008 for our 2007 business activity. We recorded a $15 million liability in 2006 to reflect the impact that this change had on our liability for additional deferred income taxes at the date of enactment. We expect our effective income tax rate to be 38% in 2007.

At December 31, 2006, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $631.1 million. We also had approximately $3.6 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $15.9 million of percentage depletion carryforwards. The NOL carryforwards expire from 2011 through 2026. The value of the remaining carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs.

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

In the event of an ownership change (as defined for income tax purposes), Section 382 of the Code imposes an annual limitation on the amount of a corporation's taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Certain NOLs acquired through various acquisitions are also subject to limitations. The following table summarizes our net operating losses as of December 31, 2006 and any related limitations:

	Net Operating Losses		
	Total	**Limited**	**Annual Limitation**
		($ in thousands)	
Net operating loss	$ 631,123	$ 30,570	$ 15,568
AMT net operating loss	$ 3,565	$ 3,565	$ 520

As of December 31, 2006, we do not believe that an ownership change has occurred. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs. Following an ownership change, the amount of Chesapeake's NOLs available for use each year will depend upon future events that cannot currently be predicted and upon interpretation of complex rules under Treasury regulations. If less than the full amount of the annual limitation is utilized in any given year, the unused portion may be carried forward and may be used in addition to successive years' annual limitation.

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

Title to Properties

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

Operating Hazards and Insurance

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

Chesapeake maintains a $50 million oil and natural gas lease operator policy that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. There is no assurance that this insurance will be adequate to cover all losses or exposure to liability. Chesapeake also carries a $200 million comprehensive general liability umbrella policy and a $100 million pollution liability policy. We provide workers' compensation insurance coverage to employees in all states in which we operate and we maintain a $1 million employment practice liability policy. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks.

Facilities

Chesapeake owns an office complex in Oklahoma City and also owns or leases various field offices in the following locations:

- Arkansas: Searcy
- Illinois: Chicago
- Kansas: Garden City
- Kentucky: Gray, Elkhorn City, Hueysville, Inez and Prestonsburg
- Louisiana: Cheneyville, Goldonna and Shreveport
- New Mexico: Carlsbad, Eunice, Hobbs and Lovington
- New York: Hammondsport
- North Dakota: Dickinson
- Oklahoma: Arkoma, Billings, El Reno, Elk City, Enid, Forgan, Kingfisher, Lindsay, Oklahoma City, Waynoka, Weatherford, Wilburton, Woodward and Sayre
- Pennsylvania: Mt. Morris
- Tennessee: Egan
- Texas: Borger, Bryan, Cleburne, College Station, Dumas, Ft. Worth, Garrison, Marshall, Midland, Ozona, Pecos, Tyler, Victoria and Zapata
- West Virginia: Branchland, Buckhannon, Cedar Grove, Charleston, Clendenin, Kermit, Shrewsbury and Tad

Employees

Chesapeake had approximately 4,900 employees as of December 31, 2006, which includes 1,625 employed by our service operations companies. As a result of the CNR acquisition, approximately 135 of our employees were covered by a collective bargaining agreement with the United Steel Workers of America ("USWA") which expired effective December 1, 2006. We have continued to operate under the terms of the collective bargaining agreement while we are negotiating with the USWA. Contract negotiations began in October 2006 and are being mediated by the National Mediation Board. There have been no strikes, work stoppages, pickets or slow-downs since the expiration of the contract, although no assurances can be given that such actions will not occur.

Glossary of Oil and Natural Gas Terms

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent.

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

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

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

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

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

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

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

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

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

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

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

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

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

Mbtu. One thousand btus.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of natural gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of natural gas equivalent.

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

NYMEX. New York Mercantile Exchange.

Present Value or PV-10. When used with respect to oil and natural gas reserves, present value or PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Productive Well. A well that is producing oil or natural gas or that is capable of production.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production responses that increased recovery will be achieved.

Proved Reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved Undeveloped Location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved Undeveloped Reserves. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves may not include estimates attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Reserve Replacement. Calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries and other additions and acquisitions) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table located in Note 11 of the notes to our consolidated financial statements. In calculating reserve replacement, we do not use unproved reserve quantities or proved reserve additions attributable to less than wholly owned consolidated entities or investments accounted for using the equity method. Management uses the reserve replacement ratio as an indicator of the company's ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

Royalty Interest. An interest in an oil and natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

Standardized Measure of Discounted Future Net Cash Flows. The discounted future net cash flows relating to proved reserves based on year-end prices, costs and statutory tax rates (adjusted for permanent differences) and a 10-percent annual discount rate.

Tcf. One trillion cubic feet.

Tcfe. One trillion cubic feet of natural gas equivalent.

Undeveloped Acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working Interest. The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

ITEM 1A. *Risk Factors*

Oil and natural gas prices are volatile. A decline in prices could adversely affect our financial position, financial results, cash flows, access to capital and ability to grow.

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

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

- worldwide and domestic supplies of oil and natural gas;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity and capacity of natural gas pipelines and other transportation facilities;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;

- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and natural gas prices do not necessarily move in tandem. Because approximately 93% of our reserves at December 31, 2006 were natural gas reserves, we are more affected by movements in natural gas prices.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2006, we had long-term indebtedness of approximately $7.4 billion, with $178 million of outstanding borrowings drawn under our revolving bank credit facility. Our long-term indebtedness represented 40% of our total book capitalization at December 31, 2006. As of February 23, 2007, we had approximately $1.033 billion outstanding under our revolving bank credit facility.

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

- a portion of our cash flows from operating activities must be used to service our indebtedness and pay dividends on our preferred stock and is not available for other purposes;
- we may be at a competitive disadvantage as compared to similar companies that have less debt;
- the covenants contained in the agreements governing our outstanding indebtedness and future indebtedness may limit our ability to borrow additional funds, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants;
- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings will increase the interest rate and fees we pay on our revolving bank credit facility; and
- we may be more vulnerable to general adverse economic and industry conditions.

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

In addition, our bank borrowing base is subject to periodic redetermination. A lowering of our borrowing base could require us to repay indebtedness in excess of the borrowing base, or we might need to further secure the lenders with additional collateral.

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial and other resources than we do.

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation, exploration and production. We face intense competition from both major and other independent oil and natural gas companies in each of the following areas:

- seeking to acquire desirable producing properties or new leases for future exploration; and
- seeking to acquire the equipment and expertise necessary to develop and operate our properties.

Many of our competitors have financial and other resources substantially greater than ours, and some of them are fully integrated oil companies. These companies may be able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our revolving bank credit facility and debt and equity issuances. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and natural gas, and our success in developing and producing new reserves. If revenues were to decrease as a result of lower oil and natural gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may not be able to access additional bank debt, debt or equity or other methods of financing on an economic basis to meet these requirements.

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

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. In addition, approximately 38% of our total estimated proved reserves (by volume) at December 31, 2006 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates reflect that our production rate on producing properties will decline approximately 25% from 2007 to 2008. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

The actual quantities and present value of our proved reserves may prove to be lower than we have estimated.

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

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

At December 31, 2006, approximately 38% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. These reserve estimates include the assumption that we will make significant capital expenditures to develop the reserves, including approximately $2.7 billion in 2007. You should be aware that the estimated costs may not be accurate, development may not occur as scheduled and results may not be as estimated.

You should not assume that the present values referred to in this report represent the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The December 31, 2006 present value is based on weighted average oil and natural gas wellhead prices of $56.25 per barrel of oil and $5.41 per mcf of natural gas. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

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

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

Acquisitions may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

Our growth during the past few years is due in large part to acquisitions of exploration and production companies, producing properties and undeveloped leasehold. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire oil and natural gas properties may exceed the value we realize.

We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. When we make entity acquisitions, we may have transferee liability that is not fully indemnified. Our acquisition of Columbia Natural Resources, LLC (CNR) in November 2005 was made subject to claims which are covered in part by the indemnification of a prior owner, NiSource Inc. NiSource and Chesapeake are co-defendants in a class action lawsuit brought by royalty owners in West Virginia in which the jury returned a verdict in January 2007 awarding plaintiffs $404 million, consisting of $134 million in compensatory damages and $270 million in punitive damages. Although Chesapeake believes its share of damages that might ultimately be awarded in this case will not have a material adverse effect on its results of operations, financial condition or liquidity as a result of the NiSource indemnity and post-trial remedies that may be available, Chesapeake is a defendant in other cases involving acquired companies where it may have no, or only limited, indemnification rights. In any such actions we could incur significant liability.

As new owners, we may not effectively consolidate and integrate acquired operations, particularly when we make significant acquisitions outside our historical operating areas.

Significant acquisitions present operational and administrative challenges that may prove more difficult than anticipated. The failure to consolidate functions and integrate procedures, personnel and operations in an effective and timely manner may adversely affect our business and results of operations, at least temporarily. Significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. To the extent that we acquire properties substantially different from the properties in our primary operating areas or acquire properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as efficiently as in our prior acquisitions.

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

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

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

Future price declines may result in a write-down of our asset carrying values.

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

Our ceiling test calculation as of December 31, 2006 indicated an impairment of our oil and natural gas properties of approximately $500 million, net of income tax. However, natural gas prices subsequent to December 31, 2006 have improved sufficiently to eliminate this calculated impairment. As a result, we were not required to record a write-down of our oil and natural gas properties under the full-cost method of accounting.

Our hedging activities may reduce the realized prices received for our oil and natural gas sales and require us to provide collateral for hedging liabilities.

In order to manage our exposure to price volatility in marketing our oil and natural gas, we enter into oil and natural gas price risk management arrangements for a portion of our expected production. Commodity price hedging may limit the prices we actually realize and therefore reduce oil and natural gas revenues in the future. The fair value of our oil and natural gas derivative instruments outstanding as of December 31, 2006 was an asset of approximately $344.9 billion. In addition, our commodity price risk management transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

All but two of our commodity price risk management counterparties require us to provide assurances of performance in the event that the counterparties' mark-to-market exposure to us exceeds certain levels. Most of these arrangements allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations by making collateral allocations from our revolving bank credit facility or directly pledging oil and natural gas properties, rather than posting cash or letters of credit with the counterparties. Future collateral requirements are uncertain, however, and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

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

Our revolving bank credit facility limits our borrowings to the lesser of the borrowing base and the total commitments (currently both are $2.5 billion). The borrowing base is determined periodically at the discretion of the banks and is based in part on oil and natural gas prices. Additionally, some of our indentures contain covenants limiting our ability to incur indebtedness in addition to that incurred under our revolving bank credit facility. These indentures limit our ability to incur additional indebtedness unless we meet one of two alternative tests. The first alternative is based on our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved oil and natural gas reserves as of the end of each year. The second alternative is based on the ratio of our adjusted consolidated EBITDA (as defined in the relevant indentures) to our adjusted consolidated interest expense over a trailing twelve-month period. Currently, we are permitted to incur significant additional indebtedness under both of these debt incurrence tests. Lower oil and natural gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

Oil and natural gas drilling and producing operations can be hazardous and may expose us to environmental liabilities.

Oil and natural gas operations are subject to many risks, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, and other environmental hazards and risks. Our drilling operations involve risks from high pressures and from mechanical difficulties such as stuck pipes, collapsed casings and separated cables. If any of these risks occurs, we could sustain substantial losses as a result of:

- injury or loss of life;

- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

There is inherent risk of incurring significant environmental costs and liabilities in our exploration and production operations due to our generation, handling, and disposal of materials, including wastes and petroleum hydrocarbons. We may incur joint and several, strict liability under applicable U.S. federal and state environmental laws in connection with releases of petroleum hydrocarbons and wastes on, under or from our leased or owned properties, some of which have been used for oil and natural gas exploration and production activities for a number of years, often by third parties not under our control. While we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

In addition, in response to studies suggesting that emissions of certain gases may be contributing to warming of the earth's atmosphere, many states are beginning to consider initiatives to track and record these gases, generally referred to as "greenhouse gases," with several states having already adopted regulatory initiatives and one state, California, having adopted legislation aimed at reducing emissions of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are included among the types of gases targeted by greenhouse gas initiatives and laws. This movement is in its infancy but regulatory initiatives or legislation placing restrictions on emissions of methane or carbon dioxide that may be imposed in various states of the United States could adversely affect our operations and the demand for our products.

ITEM 1B. ***Unresolved Staff Comments***

None.

ITEM 2. ***Properties***

Information regarding our properties is included in Item 1 and in Note 11 of the notes to our consolidated financial statements included in Item 8 of this report.

ITEM 3. ***Legal Proceedings***

We are involved in various disputes incidental to our business operations, including claims from royalty owners regarding volume measurements, post-production costs and prices for royalty calculations. In *Tawney, et al. v. Columbia Natural Resources, Inc.*, Chesapeake's wholly owned subsidiary Chesapeake Appalachia, L.L.C., formerly known as Columbia Natural Resources, LLC (CNR), is a defendant in a class action lawsuit in the Circuit Court of Roane County, West Virginia filed in 2003 by royalty owners. The plaintiffs allege that CNR underpaid royalties by improperly deducting post-production costs, failing to pay royalty on total volumes of natural gas produced and not paying a fair value for the natural gas produced from their leases. The plaintiff class consists of West Virginia royalty owners receiving royalties after July 31, 1990 from CNR. Chesapeake acquired CNR in November 2005, and its seller acquired CNR in 2003 from NiSource Inc. NiSource, a co-defendant in the case, has managed the litigation and indemnified Chesapeake against underpayment claims based on the use of fixed prices for natural gas production sold under certain forward sale contracts and other claims with respect to CNR's operations prior to September 2003.

On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of $404 million, consisting of $134 million in compensatory damages and $270 million in punitive damages. Most of the damages awarded by the jury relate to issues not yet addressed by the West Virginia Supreme Court of Appeals, although in June 2006 that Court ruled against the defendants on two certified questions regarding the deductibility of post-production expenses. The jury found fraud with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions.

Chesapeake and NiSource maintain CNR acted in good faith and paid royalties in accordance with lease terms and West Virginia law, and they intend to appeal any adverse judgment in the case. Chesapeake and NiSource have filed a joint motion for post-trial review of punitive damages to be heard on March 5, 2007. Chesapeake has established an accrual for amounts it believes will not be indemnified. Should a final nonappealable judgment be entered, Chesapeake believes its share of damages will not have a material adverse effect on its results of operations, financial condition or liquidity.

Chesapeake is subject to other legal proceedings and claims which arise in the ordinary course of business. In our opinion, the final resolution of these proceedings and claims will not have a material effect on the company.

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

Not applicable.

PART II

ITEM 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Price Range of Common Stock

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

	Common Stock	
	High	**Low**
Year ended December 31, 2006:		
Fourth Quarter	$ 34.27	$ 27.90
Third Quarter	33.76	28.06
Second Quarter	33.79	26.81
First Quarter	35.57	27.75
Year ended December 31, 2005:		
Fourth Quarter	$ 40.20	$ 26.59
Third Quarter	38.98	22.90
Second Quarter	24.00	17.74
First Quarter	23.65	15.06

At February 23, 2007, there were 1,522 holders of record of our common stock and approximately 300,000 beneficial owners.

Dividends

The following table sets forth the amount of dividends per share declared on Chesapeake common stock during 2006 and 2005:

	2006	2005
Fourth Quarter	$ 0.060	$ 0.050
Third Quarter	0.060	0.050
Second Quarter	0.060	0.050
First Quarter	0.050	0.045

While we expect to continue to pay dividends on our common stock, the payment of future cash dividends will depend upon, among other things, our financial condition, funds from operations, the level of our capital and development expenditures, our future business prospects, contractual restrictions and any other factors considered relevant by the board of directors.

Several of the indentures governing our outstanding senior notes contain restrictions on our ability to declare and pay cash dividends. Under these indentures, we may not pay any cash dividends on our common or preferred stock if an event of default has occurred, if we have not met one of the two debt incurrence tests described in the indentures, or if immediately after giving effect to the dividend payment, we have paid total dividends and made other restricted payments in excess of the permitted amounts. As of December 31, 2006, our coverage ratio for purposes of the debt incurrence test under the relevant indentures was 7.13 to 1, compared to 2.25 to 1 required in our indentures. Our adjusted consolidated net tangible assets exceeded 200% of our total indebtedness, as required by the second debt incurrence test in these indentures, by more than $1.1 billion.

The following table presents information about repurchases of our common stock during the three months ended December 31, 2006:

Period	Total Number of Shares Purchased [(a)]	Average Price Paid Per Share [(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[(b)]
October 1, 2006 through October 31, 2006	3,214	$ 31.275	—	—
November 1, 2006 through November 30, 2006	1,970	$ 34.020	—	—
December 1, 2006 through December 31, 2006	5,235	$ 29.864	—	—
Total	10,419	$ 31.085	—	—

(a) Includes 29 shares purchased in the open market for the matching contributions we make to our 401(k) plans, the deemed surrender to the company of 2,536 shares of common stock to pay the exercise price in connection with the exercise of employee stock options and the surrender to the company of 7,854 shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) We make matching contributions to our 401(k) plans and 401(k) make-up plan using Chesapeake common stock which is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of the company contributions. There are no other repurchase plans or programs currently authorized by the board of directors.

ITEM 6. *Selected Financial Data*

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2006, 2005, 2004, 2003 and 2002. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. In addition to changes in the annual average prices for oil and natural gas and increased production from drilling activity, significant acquisitions in recent years also impacted comparability between years. See Notes 11 and 13 of the notes to our consolidated financial statements. The table should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements, including the notes, appearing in Items 7 and 8 of this report.

	Years Ended December 31,				
	2006	2005	2004	2003	2002
Statement of Operations Data:	($ in thousands, except per share data)				
Revenues:					
Oil and natural gas sales	$ 5,618,894	$ 3,272,585	$ 1,936,176	$ 1,296,822	$ 568,187
Oil and natural gas marketing sales	1,576,391	1,392,705	773,092	420,610	170,315
Service operations revenue	130,310	—	—	—	—
Total revenues	7,325,595	4,665,290	2,709,268	1,717,432	738,502
Operating costs:					
Production expenses	489,499	316,956	204,821	137,583	98,191
Production taxes	176,440	207,898	103,931	77,893	30,101
General and administrative expenses	139,152	64,272	37,045	23,753	17,618
Oil and natural gas marketing expenses	1,521,848	1,358,003	755,314	410,288	165,736
Service operations expense	67,922	—	—	—	—
Oil and natural gas depreciation, depletion and amortization	1,358,519	894,035	582,137	369,465	221,189
Depreciation and amortization of other assets	104,240	50,966	29,185	16,793	14,009
Employee retirement expense	54,753	—	—	—	—
Provision for legal settlements	—	—	4,500	6,402	—
Total operating costs	3,912,373	2,892,130	1,716,933	1,042,177	546,844
Income from operations	3,413,222	1,773,160	992,335	675,255	191,658
Other income (expense):					
Interest and other income	25,463	10,452	4,476	2,827	7,340
Interest expense	(300,722)	(219,800)	(167,328)	(154,356)	(112,031)
Gain on sale of investment	117,396	—	—	—	—
Loss on repurchases or exchanges of Chesapeake senior notes	—	(70,419)	(24,557)	(20,759)	(2,626)
Loss on investment in Seven Seas Petroleum, Inc.	—	—	—	(2,015)	(17,201)
Total other income (expense)	(157,863)	(279,767)	(187,409)	(174,303)	(124,518)
Income before income taxes and cumulative effect of accounting change	3,255,359	1,493,393	804,926	500,952	67,140
Income tax expense (benefit):					
Current	5,000	—	—	5,000	(1,822)
Deferred	1,247,036	545,091	289,771	185,360	28,676
Total income tax expense	1,252,036	545,091	289,771	190,360	26,854
Net income before cumulative effect of accounting change, net of tax	2,003,323	948,302	515,155	310,592	40,286
Cumulative effect of accounting change, net of income taxes of $1,464,000	—	—	—	2,389	—
Net Income	2,003,323	948,302	515,155	312,981	40,286
Preferred stock dividends	(88,645)	(41,813)	(39,506)	(22,469)	(10,117)
Loss on conversion/exchange of preferred stock	(10,556)	(26,874)	(36,678)	—	—
Net income available to common shareholders	$ 1,904,122	$ 879,615	$ 438,971	$ 290,512	$ 30,169
Earnings per common share— basic:					
Income before cumulative effect of accounting change	$ 4.78	$ 2.73	$ 1.73	$ 1.36	$ 0.18
Cumulative effect of accounting change	—	—	—	0.02	—
	$ 4.78	$ 2.73	$ 1.73	$ 1.38	$ 0.18
Earnings per common share— assuming dilution:					
Income before cumulative effect of accounting change	$ 4.35	$ 2.51	$ 1.53	$ 1.20	$ 0.17
Cumulative effect of accounting change	—	—	—	0.01	—
	$ 4.35	$ 2.51	$ 1.53	$ 1.21	$ 0.17
Cash dividends declared per common share	$ 0.23	$ 0.195	$ 0.17	$ 0.135	$ 0.06
Cash Flow Data:					
Cash provided by operating activities	$ 4,843,474	$ 2,406,888	$ 1,432,274	$ 938,907	$ 428,797
Cash used in investing activities	8,942,499	6,921,378	3,381,204	2,077,217	779,745
Cash provided by financing activities	4,041,517	4,567,621	1,915,245	931,254	480,991
Balance Sheet Data (at end of period):					
Total assets	$24,417,167	$16,118,462	$ 8,244,509	$ 4,572,291	$ 2,875,608
Long-term debt, net of current maturities	7,375,548	5,489,742	3,075,109	2,057,713	1,651,198
Stockholders' equity	11,251,471	6,174,323	3,162,883	1,732,810	907,875

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

Financial Data

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

	Years Ended December 31, 2006	2005	2004
Net Production:			
Oil (mbbls)	8,654	7,698	6,764
Natural gas (mmcf)	526,459	422,389	322,009
Natural gas equivalent (mmcfe)	578,383	468,577	362,593
Oil and Natural Gas Sales ($ in thousands):			
Oil sales	$ 526,687	$ 401,845	$ 260,915
Oil derivatives – realized gains (losses)	(14,875)	(34,132)	(69,267)
Oil derivatives – unrealized gains (losses)	28,459	4,374	3,454
Total oil sales	540,271	372,087	195,102
Natural gas sales	3,343,056	3,231,286	1,789,275
Natural gas derivatives – realized gains (losses)	1,268,528	(367,551)	(85,634)
Natural gas derivatives – unrealized gains (losses)	467,039	36,763	37,433
Total natural gas sales	5,078,623	2,900,498	1,741,074
Total oil and natural gas sales	$ 5,618,894	$ 3,272,585	$ 1,936,176
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 60.86	$ 52.20	$ 38.57
Natural gas ($ per mcf)	$ 6.35	$ 7.65	$ 5.56
Natural gas equivalent ($ per mcfe)	$ 6.69	$ 7.75	$ 5.65
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 59.14	$ 47.77	$ 28.33
Natural gas ($ per mcf)	$ 8.76	$ 6.78	$ 5.29
Natural gas equivalent ($ per mcfe)	$ 8.86	$ 6.90	$ 5.23
Other Operating Income[(a)] ($ in thousands):			
Oil and natural gas marketing	$ 54,543	$ 34,702	$ 17,778
Service operations	$ 62,388	$ —	$ —
Other Operating Income ($ per mcfe):			
Oil and natural gas marketing	$ 0.09	$ 0.07	$ 0.05
Service operations	$ 0.11	$ —	$ —
Expenses ($ per mcfe):			
Production expenses	$ 0.85	$ 0.68	$ 0.56
Production taxes[(b)]	$ 0.31	$ 0.44	$ 0.29
General and administrative expenses	$ 0.24	$ 0.14	$ 0.10
Oil and natural gas depreciation, depletion and amortization	$ 2.35	$ 1.91	$ 1.61
Depreciation and amortization of other assets	$ 0.18	$ 0.11	$ 0.08
Interest expense [(c)]	$ 0.52	$ 0.47	$ 0.45
Interest Expense ($ in thousands):			
Interest expense	$ 300,450	$ 226,330	$ 162,781
Interest rate derivatives – realized (gains) losses	1,898	(4,945)	(791)
Interest rate derivatives – unrealized (gains) losses	(1,626)	(1,585)	5,338
Total interest expense	$ 300,722	$ 219,800	$ 167,328
Net Wells Drilled	1,449	816	546
Net Producing Wells as of the End of Period	19,079	16,985	8,058

(a) Includes revenue and operating costs and excludes depreciation and amortization of other assets.

(b) Production taxes in 2006 include an $11.6 million reversal, or $0.02 per mcfe, of production taxes as a result of the dismissal of certain production tax claims. The $11.6 million accrual consisted of $2.1 million in accruals made during 2006 and $9.5 million in accruals made during 2005. Production taxes in 2004 include a benefit of $6.8 million, or $0.02 per mcfe, from 2003 severance tax credits.

(c) Includes the effects of realized gains (losses) from interest rate derivatives, but excludes the effects of unrealized gains (losses) and is net of amounts capitalized

We manage our business as three separate segments: an exploration and production segment, a marketing segment and a service operations segment which is comprised of our wholly owned drilling and trucking subsidiaries. We refer you to Note 8 of the notes to our consolidated financial statements appearing in Item 8 of this report, which summarizes by segment our net income and capital expenditures for 2006, 2005 and 2004 and our assets as of December 31, 2006, 2005 and 2004.

Executive Summary

Chesapeake is the third largest independent producer of natural gas in the United States. We own interests in approximately 34,600 producing oil and natural gas wells that are currently producing approximately 1.7 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves in the U.S. east of the Rocky Mountains. Our most important operating area has historically been in various conventional plays in the *Mid-Continent region* of Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle. At December 31, 2006, 47% of our estimated proved oil and natural gas reserves were located in the Mid-Continent region. During the past five years, we have also built significant positions in various conventional and unconventional plays in the *Fort Worth Basin* in north-central Texas; the *Appalachian Basin*, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York; the *Permian and Delaware Basins* of West Texas and eastern New Mexico; the *Ark-La-Tex* area of East Texas and northern Louisiana; and the South *Texas and Texas Gulf Coast regions*. We have established a top-three position in nearly every major shale play in the U.S., including the Forth Worth Basin Barnett Shale, the Arkansas Fayetteville Shale, the Appalachian Basin Devonian Shale, the southeast Oklahoma Woodford Shale, the Delaware Basin Barnett and Woodford Shales, the Illinois Basin New Albany Shale and the Conasauga, Floyd and Chattanooga Shales in Alabama.

Oil and natural gas production for 2006 was 578.4 bcfe, an increase of 109.8 bcfe, or 23% over the 468.6 bcfe produced in 2005. We have increased our production for 17 consecutive years and 22 consecutive quarters. During these 22 quarters, Chesapeake's U.S. production has increased 322% for an average compound quarterly growth rate of 6.8% and an average compound annual growth rate of 29.7%.

In addition to increased oil and natural gas production, the prices we received were higher in 2006 than in 2005. On a natural gas equivalent basis, weighted average prices (excluding the effect of unrealized gains or losses on derivatives) were $8.86 per mcfe in 2006 compared to $6.90 per mcfe in 2005. The increase in prices resulted in an increase in revenue of $1.135 billion, and increased production resulted in an increase in revenue of $757.2 million, for a total increase in revenue of $1.892 billion (excluding the effect of unrealized gains or losses on derivatives). In each of the operating areas where Chesapeake sells its oil and natural gas, established marketing and transportation infrastructures exist, thereby contributing to relatively high wellhead price realizations for our production.

During 2006, we led the nation in drilling activity with an average utilization of 98 operated rigs and 79 non-operated rigs. Through this drilling activity, we drilled 1,488 (1,243 net) operated wells and participated in another 1,534 (206 net) wells operated by other companies. Our success rate was 99% for operated wells and 98% for non-operated wells. To accelerate the development of our extensive prospect inventory, we have increased our current drilling activity to 132 operated rigs and we anticipate keeping our operated rig count between 130 and 140 rigs during 2007. In 2006, we added approximately 2,000 new employees to support our growth, which increased our total employee base to approximately 4,900 employees at December 31, 2006 and invested $771 million in leasehold (excluding leasehold acquired through corporate and asset acquisitions) and 3-D seismic data, all of which we consider the building blocks of future value creation.

Chesapeake began 2006 with estimated proved reserves of 7.521 tcfe and ended the year with 8.956 tcfe, an increase of 1.435 tcfe, or 19%. During 2006, we replaced 578.4 bcfe of production with an estimated 2.013 tcfe of new proved reserves, for a reserve replacement rate of 348%. Reserve replacement through the drillbit was 1.345 tcfe, or 233% of production (including 729 bcfe of positive performance revisions and 212 bcfe of downward revisions resulting from natural gas price declines between December 31, 2005 and December 31, 2006) and 67% of the total increase. Reserve replacement through the acquisition of proved reserves was 668 bcfe, or 115% of production and 33% of the total increase. Our annual decline rate on producing properties is projected to be 25% from 2007 to 2008, 16% from 2008 to 2009, 13% from 2009 to 2010, 11% from 2010 to 2011 and 10% from 2011 to 2012. Our percentage of proved undeveloped reserve additions to total proved reserve additions was approximately 38% in 2006, 36% in 2005 and 56% in 2004. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2006 will begin producing within the next three to five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within one year.

Chesapeake attributes its strong drilling results and production growth during 2006 (and in this decade) to management's early recognition that oil and natural gas prices were undergoing structural change and its subsequent decision to invest aggressively in the building blocks of value creation in the E&P industry – people, land and seismic. During the past five years, Chesapeake has significantly strengthened its technical capabilities by increasing its land, geoscience and engineering staff to approximately 1,000 employees. Today, the company has approximately 4,900 employees, of which approximately 60% work in the company's E&P operations and 40% work in the company's oilfield service operations.

Since 2000, Chesapeake has invested $6.6 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be one of the largest inventories of onshore leasehold (10.4 million net acres) and 3-D seismic (16.3 million acres) in the U.S. On this leasehold, the company has an estimated 26,000 net drilling locations representing an approximate 10-year inventory of drilling projects.

Chesapeake's direct and indirect drilling rig investments have served as an effective hedge to higher service costs and have also provided competitive advantages in making acquisitions and in developing the company's own leasehold on a more timely and efficient basis. As of December 31, 2006, Chesapeake had invested approximately $300 million to build or acquire 42 drilling rigs and to begin the construction of 14 additional rigs. During 2006, the company entered into a sale/leaseback transaction to monetize its investment in 24 rigs in exchange for cash proceeds of approximately $244 million. These rigs are under lease to Chesapeake through 2014 at which time the company has the option to reacquire them. Including the 24 rigs sold and subsequently leased back to Chesapeake, the company's drilling rig fleet should reach 81 rigs by mid-year 2007, which would rank Chesapeake as the sixth largest drilling rig contractor in the U.S. Additionally, the company has a $77 million investment in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake's equity ownership is approximately 45% and 49%, respectively. DHS owns 16 rigs and Mountain is operating 4 rigs and has another 4 rigs under construction or on order for delivery in 2007.

To further hedge its exposure to oilfield service costs and achieve greater operational efficiency, in 2006 Chesapeake invested $254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. It also has expansion efforts underway in many other key regions in which Chesapeake operates.

As of December 31, 2006, the company's debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders' equity) was 40% compared to 47% as of December 31, 2005. During 2006, we received net proceeds of $4.071 billion through issuances of $575 million of preferred equity, $1.8 billion of common equity and $1.8 billion principal amount of senior notes. We used the net proceeds from these offerings primarily to fund the purchase price for acquisitions and to repay outstanding indebtedness under our revolving bank credit facility. As a result of our debt transactions in 2005 and 2006, we have extended the average maturity of our long-term debt to over nine years with an average interest rate of approximately 6.5%.

We intend to continue to focus on improving the strength of our balance sheet. We believe our business strategy and operational performance will lead to an investment grade credit rating for our unsecured debt at some point in the future.

Liquidity and Capital Resources

Sources of Liquidity and Uses of Funds

Our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for certain acquisitions) is cash flow from operations. Based on our current production, price and expense assumptions, we expect our drilling, land and seismic capital expenditures in 2007 to exceed our cash flow from operations. Any additional funds required will be provided through additional borrowings under our bank credit facility. Our budget for drilling, land and seismic activities during 2007 is currently between $4.7 billion and $4.9 billion. We believe this level of exploration and development will be sufficient to increase our proved oil and natural gas reserves in 2007 and increase our total production by 14% to 18% (inclusive of acquisitions completed or scheduled to close in 2007 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2007). However, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary.

Cash provided by operating activities was $4.843 billion in 2006, compared to $2.407 billion in 2005 and $1.432 billion in 2004. The $2.436 billion increase from 2005 to 2006 and the $975 million increase from 2004 to 2005 were primarily due to higher realized prices and higher volumes of oil and natural gas production. We expect that 2007 production volumes will be higher than in 2006 and that cash provided by operating activities in 2007 will exceed 2006 levels. While a decline in natural gas prices in 2007 would affect the amount of cash flow that would be generated from operations, we currently have oil swaps in place covering 59% of our expected oil production in 2007 at an average NYMEX price of $71.90 per barrel of oil and natural gas swaps in place covering 48% of our expected natural gas production in 2007 at an average NYMEX price of $8.63 per mcf, along with natural gas collars covering 10% of our anticipated natural gas production for 2007 with an average NYMEX floor of $6.88 per mcf and an average NYMEX ceiling of $8.41 per mcf. Additionally, we have written call options covering 10% of our 2007 natural gas production at a weighted average price of $9.56. This level of hedging provides certainty of the cash flow we will receive for a substantial portion of our 2007 production. Depending on changes in oil and natural gas futures markets and management's view of underlying oil and natural gas supply and demand trends, however, we may increase or decrease our current hedging positions.

Based on fluctuations in natural gas and oil prices, our hedging counterparties may require us to deliver cash collateral or other assurances of performance from time to time. All but three of our commodity price risk management counterparties require us to provide assurances of performance in the event that the counterparties' mark-to-market exposure to us exceeds certain levels. Most of these arrangements allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations by making collateral allocations from our bank credit facility or directly pledging oil and natural gas properties, rather than posting cash or letters of credit with the counterparties. As of December 31, 2006, we had outstanding collateral allocations and pledges of oil and natural gas properties, with respect to commodity price risk management transactions but were not required to post any collateral with our counterparties through letters of credit issued under our bank credit facility. As of February 23, 2007, we had outstanding transactions with fifteen counterparties, eight of which hold collateral allocations from our bank facility or liens against certain oil and natural gas properties under our secured hedging facilities, and two of which do not require us to provide security for our risk management transactions. As of February 23, 2007, we were not required to post cash or letters of credit with the remaining five counterparties. Future collateral requirements are uncertain and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

A significant source of liquidity is our $2.5 billion syndicated revolving bank credit facility which matures in February 2011. At February 23, 2007, there was $1.464 billion of borrowing capacity available under the revolving bank credit facility. We use the facility to fund daily operating activities and acquisitions as needed. We borrowed $8.370 billion and repaid $8.264 billion in 2006, we borrowed $5.682 billion and repaid $5.669 billion in 2005 and we borrowed $2.160 billion and repaid $2.101 billion in 2004 under our bank credit facility. We incurred $5.1 million, $4.7 million and $2.2 million of financing costs related to our revolving bank credit facility in 2006, 2005 and 2004, respectively, as a result of amendments to the credit facility agreement. During 2005, we repaid the remaining credit facility balance of $96.1 million assumed in our 2005 acquisition of Columbia Natural Resources, LLC.

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

The public and institutional markets have been our principal source of long-term financing for acquisitions. We have sold debt and equity in both public and private offerings in the past, and we expect that these sources of capital will continue to be available to us in the future to finance acquisitions. Nevertheless, we caution that ready access to capital on reasonable terms and the availability of desirable acquisition targets at attractive prices are subject to many uncertainties, as explained under “Risk Factors” in Item 1A.

The following table reflects the proceeds from sales of securities we issued in 2006, 2005 and 2004 ($ in millions):

	2006		2005		2004	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Unsecured senior notes guaranteed by subsidiaries	$ 1,799.5	$ 1,754.8	$ 2,300.0	$ 2,251.3	$ 1,200.0	$ 1,166.0
Contingent convertible unsecured senior notes	—	—	690.0	673.3	—	—
Convertible preferred stock	575.0	557.6	1,380.0	1,341.5	313.3	304.9
Common stock	1,799.7	1,759.0	1,024.6	985.8	650.0	624.2
Total	$ 4,174.2	$ 4,071.4	$ 5,394.6	$ 5,251.9	$ 2,163.3	$ 2,095.1

We qualify as a “well-known seasoned issuer” (WKSI), as defined in Rule 405 of the Securities Act of 1933, and therefore we may utilize automatic shelf registration to register future debt and equity issuances with the Securities and Exchange Commission. A prospectus supplement will be prepared at the time of an offering and will contain a description of the security issued, the plan of distribution and other information.

We paid dividends on our common stock of $87.0 million, $60.5 million and $38.9 million in 2006, 2005 and 2004, respectively, and we paid dividends on our preferred stock of $88.4 million, $31.5 million and $40.9 million in 2006, 2005 and 2004, respectively. We received $73.2 million, $21.6 million and $12.0 million from the exercise of employee and director stock options and warrants in 2006, 2005 and 2004, respectively. We paid $86.2 million and $4.0 million to purchase treasury stock in 2006 and 2005. Of these amounts, $11.1 million and $4.0 million were used to fund our matching contribution to our 401(k) plans in 2006 and 2005, respectively. The remaining $75.1 million in 2006 was used to purchase shares of common stock to be used upon the exercise of stock options under certain stock option plans. There were no treasury stock purchases made in 2004.

In 2006 and 2005, we paid $86.9 million and $11.6 million to settle a portion of the derivative liabilities assumed in our 2005 acquisition of Columbia Natural Resources, LLC.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased by $70.0 million, $61.2 million and $88.3 million in 2006, 2005 and 2004, respectively. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facility.

Historically, we have used significant funds to redeem or purchase and retire outstanding senior notes issued by Chesapeake, although we had no such transactions in 2006. The following table shows our redemption, purchases and exchanges of senior notes for 2005 and 2004 ($ in millions):

	Senior Notes Activity				
For the Year Ended December 31, 2005:	Retired	Premium	Other[(a)]	Issued	Cash Paid
8.375% Senior Notes due 2008	$ 19.0	$ 1.2	$ —	$ —	$ 20.2
8.125% Senior Notes due 2011	245.4	17.3	0.7	—	263.4
9.0% Senior Notes due 2012	300.0	41.4	0.8	—	342.2
	$ 564.4	$ 59.9	$ 1.5	$ —	$ 625.8
For the Year Ended December 31, 2004:					
8.375% Senior Notes due 2008	$ 190.8	$ 16.1	$ 0.5	$ —	$ 207.4
7.875% Senior Notes due 2004	42.1	—	—	—	42.1
8.5% Senior Notes due 2012	4.3	0.2	—	—	4.5
8.125% Senior Notes due 2011[(b)]	482.8	—	62.1	(534.2)	10.7
	$ 720.0	$ 16.3	$ 62.6	$ (534.2)	$ 264.7

(a) Includes adjustments to accrued interest and discount associated with notes retired and new notes issued, cash in lieu of fractional notes, transaction costs and fair value hedging adjustments.
(b) We issued $63.7 million of our 7.75% Senior Notes and $470.5 million of our 6.875% Senior Notes.

Our accounts receivable are primarily from purchasers of oil and natural gas ($617.8 million at December 31, 2006) and exploration and production companies which own interests in properties we operate ($135.3 million at December 31, 2006). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

Investing Transactions

Cash used in investing activities increased to $8.942 billion in 2006, compared to $6.921 billion in 2005 and $3.381 billion in 2004. The following table shows our capital expenditures during these years ($ in millions):

Oil and Natural Gas Investing Activities:	2006	2005	2004
Acquisitions of oil and natural gas companies and proved properties, net of cash acquired	$ 1,104.2	$ 2,759.1	$ 1,484.2
Acquisition of unproved properties	2,855.8	1,375.7	570.5
Exploration and development of oil and natural gas properties	3,008.7	1,793.4	960.1
Leasehold acquisitions	616.6	290.9	110.5
Geological and geophysical costs	154.0	70.9	55.6
Other oil and natural gas activities	(0.1)	(2.4)	(1.9)
Total oil and natural gas investing activities	7,739.2	6,287.6	3,179.0
Other Investing Activities:			
Additions to buildings and other fixed assets	593.7	417.5	126.7
Additions to drilling rig equipment	392.7	66.8	23.1
Proceeds from sale of drilling rigs and equipment	(243.6)	—	—
Additions to investments	554.6	135.0	37.0
Proceeds from sale of investment in Pioneer Drilling Company	(158.9)	—	—
Acquisition of trucking company, net of cash acquired	45.2	—	—
Deposits for acquisitions	21.7	35.0	16.3
Sale of non-oil and natural gas investments	(1.9)	(20.5)	(0.9)
Other	(0.2)	—	—
Total other investing activities	1,203.3	633.8	202.2
Total cash used in (provided by) investing activities	$ 8,942.5	$ 6,921.4	$ 3,381.2

In 2006, we expanded our service operations through a number of acquisitions. In January 2006, we acquired a privately-owned Oklahoma-based oilfield trucking service company for $47.5 million. In February 2006, we acquired 13 drilling rigs and related assets through our wholly owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-owned drilling contractor with operations in East Texas and North Louisiana, for approximately $150 million. In July 2006, we acquired 15 rigs and related trucking assets from a drilling contractor in the Appalachian Basin for approximately $70 million in cash.

In February 2006, we sold our investment in publicly-traded Pioneer Drilling Company ("Pioneer") common stock, realizing proceeds of $158.9 million and a gain of $117.4 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

In August 2006, we invested $254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services, with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the

Rocky Mountains. In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for $240 million in cash and 1,375,989 newly issued shares of our common stock valued at $40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma.

Financing Transactions

During 2005 and 2006, we took several steps to improve our capital structure. These transactions enabled us to extend our average maturity of long-term debt to over nine years with an average interest rate of approximately 6.5%. Maintaining a debt-to-total-capitalization ratio below 50% and reducing debt per mcfe of proved reserves remain key goals of our business strategy.

We completed the following significant financing transactions in 2006:

First Quarter 2006

- Amended and restated our revolving bank credit facility, increasing the commitments to $2.0 billion and extending the maturity date to February 2011.
- Issued an additional $500 million of our 6.5% Senior Notes due 2017 in a private placement and used the proceeds of approximately $487 million to repay outstanding borrowings under our revolving bank credit facility incurred primarily to fund our recent acquisitions.

Second Quarter 2006

- Exchanged 83,245 shares of our 4.125% cumulative convertible preferred stock, representing 96.4% or $83.2 million of the aggregate liquidation value of the shares outstanding, for 5.2 million shares of our common stock pursuant to a tender offer.
- Exchanged 804,048 shares of our 5.0% (Series 2003) cumulative convertible preferred stock, representing 95.4% or $80.4 million of the aggregate liquidation value of the shares outstanding, for 5.0 million shares of our common stock pursuant to a tender offer.
- Completed public offerings of $500 million of 7.625% Senior Notes due 2013, 2.0 million shares of 6.25% mandatory convertible preferred stock having a liquidation preference of $250 per share, and 25 million shares of common stock at $29.05 per share. Net proceeds of approximately $1.666 billion were used to fund acquisitions, to repay borrowings under our revolving bank credit facility and for general corporate purposes.

Third Quarter 2006

- Increased the commitments under our revolving bank credit facility to $2.5 billion.
- Issued 3.75 million shares of common stock at $29.05 per share and 300,000 shares of our 6.25% mandatory convertible preferred stock having a liquidation preference of $250 per share upon the exercise of the underwriters' options to purchase the additional shares pursuant to the June 2006 public offerings of our common stock and 6.25% preferred stock. Net proceeds of approximately $177.6 million were used to repay borrowings under our revolving bank credit facility.

Fourth Quarter 2006

- Completed a public offering on December 5, 2006 of €600 million of 6.25% Euro-denominated Senior Notes due 2017 ($799.5 million based on the dollar/euro exchange rate of $1.3325 to €1.00). Net proceeds of approximately €589.6 million (or approximately $785.7 million) were used to repay outstanding borrowings under our revolving bank credit facility.
- Completed a public offering of 30 million shares of common stock at $32.15 per share. Net proceeds of approximately $955.3 million were used to repay outstanding borrowings under our revolving bank credit facility.

Contractual Obligations

We currently have a $2.5 billion syndicated revolving bank credit facility which matures in February 2011. Commitments under the credit facility were increased from $1.25 billion to $2.0 billion in February 2006 and to $2.5 billion in September 2006. As of December 31, 2006, we had $178.0 million in outstanding borrowings under this facility and had utilized $6.2 million of the facility for various letters of credit. Borrowings under the facility are collateralized by certain producing oil and natural gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A., or the federal funds effective rate plus 0.50% or (ii) London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently the commitment fee is 0.25% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility, our indebtedness to total capitalization ratio was 0.40 to 1 and our indebtedness to EBITDA ratio was 1.64 to 1 at December 31, 2006. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

We have three secured hedging facilities maturing in 2011, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a maximum value. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. The hedging facilities are subject to a 1% per annum exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate oil and natural gas production volumes that we are permitted to hedge under all of our agreements at any one time. The maximum permitted value of transactions under each facility and the fair market values of outstanding transactions are shown below.

	Secured Hedging Facilities		
	#1	#2	#3
		($ in thousands)	
Maximum permitted value of transactions under facility	$ 750,000	$ 500,000	$ 500,000
Fair market value of outstanding transactions, as of December 31, 2006	$ 34,403	$ 59,639	$ —
Fair market value of outstanding transactions, as of February 23, 2007	$ 26,063	$ 16,027	$ 29,243

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake Exploration Limited Partnership is the named party to our hedging facilities. The facilities are guaranteed by Chesapeake and all its other wholly owned subsidiaries except minor subsidiaries. Our revolving bank credit facility and secured hedging facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates and commitment fees in our bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, the bank facility and the secured hedging facilities do not contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

In addition to outstanding revolving bank credit facility borrowings discussed above, as of December 31, 2006, senior notes represented approximately $7.2 billion of our long-term debt and consisted of the following ($ in thousands):

7.5% Senior Notes due 2013	$ 363,823
7.625% Senior Notes due 2013	500,000
7.0% Senior Notes due 2014	300,000
7.5% Senior Notes due 2014	300,000
7.75% Senior Notes due 2015	300,408
6.375% Senior Notes due 2015	600,000
6.625% Senior Notes due 2016	600,000
6.875% Senior Notes due 2016	670,437
6.5% Senior Notes due 2017	1,100,000
6.25% Euro-denominated Senior Notes due 2017 [a]	791,820
6.25% Senior Notes due 2018	600,000
6.875% Senior Notes due 2020	500,000
2.75% Contingent Convertible Senior Notes due 2035	690,000
Discount on senior notes	(101,935)
Discount for interest rate derivatives	(17,005)
	$7,197,548

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3197 to €1.00 as of December 31, 2006. See Note 10 of our financial statements for information on our related cross currency swap.

No scheduled principal payments are required under our senior notes until 2013, when $863.8 million is due. The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of these notes.

As of December 31, 2006 and currently, debt ratings for the senior notes are Ba2 by Moody's Investor Service (stable outlook), BB by Standard & Poor's Ratings Services (positive outlook) and BB by Fitch Ratings (stable outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment with all of our future subordinated indebtedness. All of our wholly owned subsidiaries, except minor subsidiaries, fully and unconditionally guarantee the notes jointly and severally on an unsecured basis. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries' ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale-leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries' ability to incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of December 31, 2006, we estimate that secured commercial bank indebtedness of approximately $3.3 billion could have been incurred under the most restrictive indenture covenant.

The table below summarizes our contractual obligations as of December 31, 2006 ($ in thousands):

	Payments Due By Period				
Contractual Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 years**
Long-term debt obligations	$ 7,494,488	$ —	$ —	$ 178,000	$ 7,316,488
Capital lease obligations	5,834	2,491	2,905	438	—
Operating lease obligations	281,974	40,033	77,013	69,665	95,263
Purchase obligations[(a)]	1,068,387	470,182	308,822	68,922	220,461
Standby letters of credit	6,889	6,889	—	—	—
Total contractual cash obligations	$ 8,857,572	$ 519,595	$ 388,740	$ 317,025	$ 7,632,212

(a) See Note 4 of the notes to our consolidated financial statements for a description of transportation and drilling contract commitments.

Hedging Activities

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Executive management is involved in all risk management activities and the Board of Directors reviews the company's hedging program at every Board meeting. We believe we have sufficient internal controls to prevent unauthorized hedging. As of December 31, 2006, our oil and natural gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. Item 7A-Quantitative and Qualitative Disclosures About Market Risk contains a description of each of these instruments. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

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

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

Realized gains and losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas sales of $1.254 billion, or $2.17, per mcfe in 2006, a net decrease of $401.7 million, or $0.86, per mcfe in 2005 and a net decrease of $154.9 million, or $0.43, per mcfe in 2004. Oil and natural gas sales also include changes in the fair value of oil and natural gas derivatives that do not qualify as cash flow hedges under SFAS 133, as well as gains (losses) on ineffectiveness of instruments designated as cash flow hedges. Unrealized gains (losses) included in oil and natural gas sales in 2006, 2005 and 2004 were

$495.5 million, $41.1 million and $40.9 million, respectively. Included in these unrealized gains (losses) are gains (losses) on ineffectiveness of cash flow hedges of $311.1 million in 2006, ($76.3) million in 2005 and ($8.2) million in 2004.

Changes in the fair value of oil and natural gas derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of derivative contracts are recorded in accumulated other comprehensive income and are transferred to earnings in the month of related production. These unrealized gains (losses), net of related tax effects, totaled $545.9 million, ($270.7) million and ($4.4) million as of December 31, 2006, 2005 and 2004, respectively. Based upon the market prices at December 31, 2006, we expect to transfer to earnings approximately $282.5 million of the net gain included in the balance of accumulated other comprehensive income during the next 12 months. A detailed explanation of accounting for oil and natural gas derivatives under SFAS 133 appears under "Application of Critical Accounting Policies - Hedging" elsewhere in this Item 7.

The estimated fair values of our oil and natural gas derivative instruments as of December 31, 2006 and 2005 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31,	
	2006	2005
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ 1,075	$ (1,081,323)
Natural gas basis protection swaps	186,970	307,308
Fixed-price natural gas cap-swaps	121,866	(161,056)
Fixed-price natural gas counter-swaps	(5,455)	37,785
Natural gas call options[(a)]	(4,873)	(21,461)
Fixed-price natural gas collars	(6,922)	(9,374)
Floating-price natural gas swaps	—	2,607
Fixed-price oil swaps	28,149	(16,936)
Fixed-price oil cap-swaps	24,057	(3,364)
Estimated fair value	$ 344,867	$ (945,814)

(a) After adjusting for $15.4 million and $23.0 million of unrealized premiums, the cumulative unrealized gain related to these call options as of December 31, 2006 and 2005 was $10.5 million and $1.6 million, respectively.

Additional information concerning the fair value of our oil and natural gas derivative instruments, including CNR derivatives assumed, is as follows:

	December 31,		
	2006	2005	2004
	($ in thousands)		
Fair value of contracts outstanding, as of January 1	$ (945,814)	$ 38,350	$ (44,988)
Change in fair value of contracts during the period	3,423,099	(771,076)	(69,927)
Fair value of contracts when entered into during the period	(32,300)	(614,772)	(5,369)
Contracts realized or otherwise settled during the period	(1,253,653)	401,684	154,901
Fair value of contracts when closed during the period	(846,465)	—	3,733
Fair value of contracts outstanding, as of December 31	$ 344,867	$ (945,814)	$ 38,350

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. Realized gains (losses) included in interest expense were ($1.9) million, $4.9 million and $0.8 million in 2006, 2005 and 2004, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were $1.6 million, $1.6 million and ($5.3) million in 2006, 2005 and 2004, respectively. A detailed explanation of accounting for interest rate derivatives under SFAS 133 appears under "Application of Critical Accounting Policies - Hedging" elsewhere in this Item 7.

Foreign Currency Derivatives

On December 5, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. A detailed explanation of accounting for foreign currency derivatives under SFAS 133 appears under "Application of Critical Accounting Policies - Hedging" elsewhere in this Item 7.

Results of Operations

General. For the year ended December 31, 2006, Chesapeake had net income of $2.003 billion, or $4.35 per diluted common share, on total revenues of $7.326 billion. This compares to net income of $948.3 million, or $2.51 per diluted common share, on total revenues of $4.665 billion during the year ended December 31, 2005, and net income of $515.2 million, or $1.53 per diluted common share, on total revenues of $2.709 billion during the year ended December 31, 2004.

Oil and Natural Gas Sales. During 2006, oil and natural gas sales were $5.619 billion compared to $3.273 billion in 2005 and $1.936 billion in 2004. In 2006, Chesapeake produced and sold 578.4 bcfe at a weighted average price of $8.86 per mcfe, compared to 468.6 bcfe in 2005 at a weighted average price of $6.90 per mcfe, and 362.6 bcfe in 2004 at a weighted average price of $5.23 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of $495.5 million, $41.1 million and $40.9 million in 2006, 2005 and 2004, respectively). The increase in prices in 2006 resulted in an increase in revenue of $1.135 billion and increased production resulted in a $757.2 million increase, for a total increase in revenues of $1.892 billion (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from period to period was due to the combination of production growth from drilling as well as acquisitions completed during those periods.

For 2006, we realized an average price per barrel of oil of $59.14, compared to $47.77 in 2005 and $28.33 in 2004 (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $8.76, $6.78 and $5.29 in 2006, 2005 and 2004, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $1.254 billion or $2.17 per mcfe in 2006, a net decrease of $401.7 million or $0.86 per mcfe in 2005 and a net decrease of $154.9 million or $0.43 per mcfe in 2004.

A change in oil and natural gas prices has a significant impact on our oil and natural gas revenues and cash flows. Assuming 2006 production levels, a change of $0.10 per mcf of natural gas sold would result in an increase or decrease in revenues and cash flow of approximately $52.6 million and $50.1 million, respectively, and a change of $1.00 per barrel of oil sold would result in an increase or decrease in revenues and cash flow of approximately $8.7 million and $8.2 million, respectively, without considering the effect of hedging activities.

The following table shows our production by region for 2006, 2005 and 2004:

	Years Ended December 31,					
	2006		2005		2004	
	Mmcfe	Percent	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	315,173	55%	297,773	64%	268,459	74%
Fort Worth Barnett Shale	44,482	7	17,409	4	—	—
Appalachian Basin	45,031	8	5,878	1	—	—
Permian and Delaware Basins	48,510	8	42,958	9	32,067	9
Ark-La-Tex	46,009	8	40,707	9	19,640	5
South Texas and Texas Gulf Coast	79,178	14	63,852	13	42,427	12
Total Production	578,383	100%	468,577	100%	362,593	100%

Natural gas production represented approximately 91% of our total production volume on an equivalent basis in 2006, compared to 90% in 2005 and 89% in 2004.

Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $1.576 billion in oil and natural gas marketing sales to third parties in 2006, with corresponding oil and natural gas marketing expenses of $1.522 billion, for a net margin before depreciation of $54 million. This compares to sales of $1.393 billion and $773 million, expenses of $1.358 billion and $755 million, and margins before depreciation of $35 million and $18 million in 2005 and 2004, respectively. In 2006 and 2005, Chesapeake realized an increase in volumes and prices related to oil and natural gas marketing sales as compared to the previous year.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our company-owned drilling and oilfield trucking operations. These operations have grown as a result of assets and businesses we acquired in 2006. Chesapeake recognized $130.3 million in service operations revenue in 2006 with corresponding service operations expenses of $67.9 million, for a net margin before depreciation of $62.4 million. During 2005 and 2004, service operations revenues and expenses for third parties were insignificant.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $489.5 million in 2006, compared to $317.0 million and $204.8 million in 2005 and 2004, respectively. On a unit-of-production basis, production expenses were $0.85 per mcfe in 2006 compared to $0.68 and $0.56 per mcfe in 2005 and 2004, respectively. The increase in 2006 was primarily due to higher third-party field service costs, fuel costs, ad valorem tax increases and personnel costs. We expect that production expenses per mcfe produced for 2007 will range from $0.90 to $1.00.

Production Taxes. Production taxes were $176.4 million in 2006 compared to $207.9 million in 2005 and $103.9 million in 2004. On a unit-of-production basis, production taxes were $0.31 per mcfe in 2006 compared to $0.44 per mcfe and $0.29 per mcfe in 2005 and 2004, respectively. The $31.5 million decrease in production taxes in 2006 is due primarily to a price decrease of approximately $1.06 per mcfe (excluding gains or losses on derivatives) which more than offset the 109.8 bcfe of increased production. In 2006, an accrual of $11.6 million for certain severance tax claims was reversed as the result of the dismissal of such claims. The $11.6 million accrual consisted of $2.1 million in accruals made during 2006 and $9.5 million in accruals made during 2005. Excluding these items, production taxes were $0.32 per mcfe in 2006 and $0.42 per mcfe in 2005. Included in 2004 is a credit of $6.8 million, or $0.02 per mcfe, related to certain Oklahoma severance tax abatements for the period July 2003 through December 2003. In April 2004, the Oklahoma Tax Commission concluded that a pre-determined oil and natural gas price cap for 2003 sales had not been exceeded (on a statewide basis) and notified the company that it was eligible to receive certain severance tax abatements for the period from July 1, 2003 through June 30, 2004. The company had previously estimated that the average oil and natural gas sales prices in Oklahoma (on a statewide basis) could exceed the price cap, and did not reflect the benefit from these potential severance tax abatements until the first quarter of 2004. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and natural gas prices are higher. We expect production taxes per mcfe to range from $0.41 to $0.46 during 2007 based on NYMEX prices of $56.09 per barrel of oil and natural gas wellhead prices ranging from $7.50 to $8.50 per mcfe.

General and Administrative Expense. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our oil and natural gas properties (see Note 11 of notes to consolidated financial statements), were $139.2 million in 2006, $64.3 million in 2005 and $37.0 million in 2004. General and administrative expenses were $0.24, $0.14 and $0.10 per mcfe for 2006, 2005 and 2004, respectively. The increase in 2006 and 2005 was the result of the company's overall growth as well as cost and wage inflation. Included in general and administrative expenses is stock-based compensation of $26.7 million in 2006, $15.3 million in 2005 and $4.8 million in 2004. Of this increase, $1.1 million was due to stock option expense, $10.2 million was due to a higher number of unvested restricted shares outstanding during 2006 compared to 2005 and $0.1 million was due to stock granted to a new director. We anticipate that general and administrative expenses for 2007 will be between $0.28 and $0.35 per mcfe produced, including stock-based compensation ranging from $0.08 and $0.10 per mcfe produced.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. We have awarded shares of restricted stock to employees since January 2004 and to non-employee directors since July 2005. Previously stock-based compensation awards were in the form of stock options. Employee stock-based compensation awards vest over a period of four years. Our non-employee director awards vest over a period of three years.

Until December 31, 2005, as permitted under Statement of Financial Accounting Standards ("SFAS") No. 123, *Accounting for Stock-Based Compensation*, as amended, we accounted for our stock options under the recognition and measurement provisions of APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Generally, we recognized no compensation cost on grants of employee and non-employee director stock options because the exercise price was equal to the market price of our common stock on the date of grant. Effective January 1, 2006, we implemented the fair value recognition provisions of SFAS 123(R), *Share-Based Payment,* using the modified-prospective transition method. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense based on the fair value on the date of grant or modification will be recognized in our financial statements over the vesting period. In addition, in accordance with Financial Accounting Standards Board Staff Position No. FAS 123(R)-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, we elected to use the "short-cut" method to calculate the historical pool of windfall tax benefits. Results for prior periods have not been restated.

The discussion of stock-based compensation in Note 1 and Note 9 of the notes to consolidated financial statements included in Item 8 of this report provides additional detail on the accounting for and reporting of our stock options and restricted stock, as well as the effects of our adoption of SFAS 123(R).

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $160.6 million, $102.2 million and $51.7 million of internal costs in 2006, 2005 and 2004, respectively, directly related to our oil and natural gas property acquisition, exploration and development efforts.

Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was $1.359 billion, $894.0 million and $582.1 million during 2006, 2005 and 2004, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $2.35, $1.91 and $1.61 in 2006, 2005 and 2004, respectively. The increase in the average rate from $1.91 in 2005 to $2.35 in 2006 is primarily the result of higher drilling costs, higher costs associated with acquisitions and the recognition of the tax effect of acquisition costs in excess of tax basis acquired in certain corporate acquisitions. We expect the 2007 DD&A rate to be between $2.40 and $2.60 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $104.2 million in 2006, compared to $51.0 million in 2005 and $29.2 million in 2004. The average D&A rate per mcfe was $0.18, $0.11 and $0.08 in 2006, 2005 and 2004, respectively. The increase in 2006 and 2005 was primarily the result of higher depreciation costs resulting from the acquisition of various gathering facilities, compression equipment and drilling rig equipment, the construction of new buildings at our corporate headquarters complex and at various field office locations and the purchase of additional information technology equipment and software in 2006 and 2005. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent company-owned drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect 2007 depreciation and amortization of other assets to be between $0.24 and $0.28 per mcfe produced.

Employee Retirement Expense. Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward's Resignation Agreement provided for the immediate vesting of all of his unvested equity awards, which consisted of options to purchase 724,615 shares of Chesapeake's common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock. As a result of this vesting, we incurred an expense of $54.8 million in 2006.

Provision for Legal Settlements. In 2004, we recorded a provision for legal settlement of $4.5 million related to various litigation incidental to our business operations.

Interest and Other Income. Interest and other income was $25.5 million, $10.5 million and $4.5 million in 2006, 2005 and 2004, respectively. The 2006 income consisted of $5.2 million of interest income, $10.3 million related to equity investments, a $4.4 million gain on sale of assets and $5.6 million of miscellaneous income. The 2005 income consisted of $3.0 million of interest income, $1.8 million of income related to equity investments and $5.7 million of miscellaneous income. The 2004 income consisted of $2.1 million of interest income, $0.8 million of income related to earnings on investments, and $1.6 million of miscellaneous income.

Interest Expense. Interest expense increased to $300.7 million in 2006 compared to $219.8 million in 2005 and $167.3 million in 2004 as follows:

	Years Ended December 31,		
	2006	2005	2004
		($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 472.2	$ 299.6	$ 194.5
Capitalized interest	(179.1)	(79.0)	(36.2)
Amortization of loan discount	7.3	5.7	4.5
Unrealized (gain) loss on interest rate derivatives	(1.6)	(1.6)	5.3
Realized (gain) loss on interest rate derivatives	1.9	(4.9)	(0.8)
Total interest expense	$ 300.7	$ 219.8	$ 167.3
Average long-term borrowings	$ 6,278	$ 3,948	$ 2,428

Interest expense, excluding unrealized (gains) losses on derivatives and net of amounts capitalized, was $0.52 per mcfe in 2006 compared to $0.47 per mcfe in 2005 and $0.45 per mcfe in 2004. We expect interest expense for 2007 to be between $0.60 and $0.65 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investment. In 2006, Chesapeake sold its investment in publicly-traded Pioneer Drilling Company ("Pioneer") common stock, realizing proceeds of $158.9 million and a gain of $117.4 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

Loss on Repurchases or Exchanges of Chesapeake Senior Notes. In 2005 and 2004, we repurchased or exchanged Chesapeake debt in order to re-finance a portion of our long-term debt at a lower rate of interest. The following table shows the losses we incurred in connection with these transactions ($ in millions):

	Notes Retired	Loss on Repurchases/Exchanges		
		Premium	Other[(a)]	Total
For the Year Ended December 31, 2005:				
8.375% Senior Notes due 2008	$ 19.0	$ 1.2	$ 0.1	$ 1.3
8.125% Senior Notes due 2011	245.4	17.3	4.4	21.7
9.0% Senior Notes due 2012	300.0	41.4	6.0	47.4
	$ 564.4	$ 59.9	$ 10.5	$ 70.4
For the Year Ended December 31, 2004:				
8.375% Senior Notes due 2008	$ 190.8	$ 16.1	$ 1.5	$ 17.6
8.5% Senior Notes due 2012	4.3	0.2	0.7	0.9
8.125% Senior Notes due 2011	482.8	—	6.0	6.0
	$ 677.9	$ 16.3	$ 8.2	$ 24.5

(a) Includes write-offs of discounts, deferred charges and interest rate derivatives associated with notes retired and transaction costs.

Income Tax Expense. Chesapeake recorded income tax expense of $1.252 billion in 2006 compared to income tax expense of $545.1 million in 2005 and $289.8 million in 2004. Of the $706.9 million increase in 2006, $643.1 million was the result of the increase in net income before taxes and $63.8 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in 2006 compared to 36.5% in 2005 and 36% in 2004. The increase in 2006 reflected the impact state income taxes and permanent differences had on our overall effective rate along with the effect of a Texas tax law change. In May 2006, Texas eliminated the existing franchise tax and replaced it with a new income-based margin tax. The new tax is effective for tax returns due on or after January 1, 2008 for our 2007 business activity. We recorded a $15 million liability in 2006 to reflect the impact that this change had on our liability for additional deferred income taxes at the date of enactment. We expect our effective income tax rate to be 38% in 2007. Most of the 2006 income tax expense was deferred and we expect most of our 2007 income tax expense to be deferred.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $10.6 million in 2006 compared to $26.9 million in 2005 and $36.7 million in 2004. The loss on the exchanges represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms. See Note 9 of notes to the consolidated financial statements in Item 8 for further detail regarding these transactions.

Application of Critical Accounting Policies

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

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

Hedging. Chesapeake uses commodity price and financial risk management instruments to mitigate our exposure to price fluctuations in oil and natural gas, changes in interest rates and changes in foreign exchange rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of oil and natural gas derivative transactions are reflected in oil and natural gas sales, and results of interest rate and foreign exchange rate hedging transactions are reflected in interest expense. The changes in the fair value of derivative instruments not qualifying for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within oil and natural gas sales or interest expense. Cash flows from derivative instruments are classified in the same category within the statement of cash flows as the items being hedged, or on a basis consistent with the nature of the instruments.

Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in oil and natural gas sales. For derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. See “Hedging Activities” above and Item 7A-Quantitative and Qualitative Disclosures About Market Risk for additional information regarding our hedging activities.

One of the primary factors that can have an impact on our results of operations is the method used to value our derivatives. We have established the fair value of all derivative instruments using estimates determined by our counterparties and subsequently confirmed the fair values internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Another factor that can impact our results of operations each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Due to the volatility of oil and natural gas prices and, to a lesser extent, interest rates and foreign exchange rates, the company’s financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2006, 2005 and 2004, the net market value of our derivatives was an asset of $292.5 million, a liability of $968.3 million and an asset of $2.5 million, respectively. The derivatives that we acquired in our CNR acquisition represented $254.4 million and $661.4 million of liability at December 31, 2006 and 2005. With respect to our derivatives held as of December 31, 2006, an increase or decrease in natural gas prices of $0.10 per mmbtu would decrease or increase the estimated fair value of our derivatives by approximately $45 million. An increase or decrease in crude oil prices of $1.00 per barrel would decrease or increase the estimated fair value of our derivatives by approximately $10 million.

Oil and Natural Gas Properties. The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full-cost method. Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities.

Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and natural gas properties are generally calculated on a well by well or lease or field basis versus the aggregated “full cost” pool basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher oil and natural gas depreciation, depletion and amortization rate, and we will not have exploration expenses that successful efforts companies frequently have.

Under the full-cost method, capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. Depreciation, depletion and amortization expense is also based on the amount of estimated reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves changes significantly. Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized. The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred. Unevaluated properties are grouped by major producing area where individual property costs are not significant and are assessed individually when individual costs are significant.

We review the carrying value of our oil and natural gas properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

The process of estimating natural gas and oil reserves is very complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates.

As of December 31, 2006, approximately 80% of our proved reserves were evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers review and update our reserves on a quarterly basis. All reserve estimates are prepared based upon a review of production histories and other geologic, economic, ownership and engineering data we developed. Additional information about our 2006 year-end reserve evaluation is included under “Oil and Natural Gas Reserves” in Item 1-Business.

In addition, the prices of natural gas and oil are volatile and change from period to period. Price changes directly impact the estimated revenues from our properties and the associated present value of future net revenues. Such changes also impact the economic life of our properties and thereby affect the quantity of reserves that can be assigned to a property.

Income Taxes. As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which Chesapeake operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as derivative instruments, depreciation, depletion and amortization, and certain accrued liabilities for tax and accounting purposes. These differences and our net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent Chesapeake establishes a valuation allowance or increases or decreases this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the consolidated statement of operations.

Under Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (a) the more positive evidence is necessary and (b) the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion or all of the deferred tax asset. Among the more significant types of evidence that we consider are:

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

If (a) natural gas and oil prices were to decrease significantly below present levels (and if such decreases were considered other than temporary), (b) exploration, drilling and operating costs were to increase significantly beyond current levels, or (c) we were confronted with any other significantly negative evidence pertaining to our ability to realize our NOL carryforwards prior to their expiration, we may be required to provide a valuation allowance against our deferred tax assets. As of December 31, 2006, we had deferred tax assets of $407.0 million.

Accounting for Business Combinations. Our business has grown substantially through acquisitions and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations using the purchase method, which is the only method permitted under SFAS 141, *Accounting for Business Combinations*. The accounting for business combinations is complicated and involves the use of significant judgment.

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

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

We believe that the consideration we have paid for our oil and natural gas property acquisitions has represented the fair value of the assets and liabilities acquired at the time of purchase. Consequently, we have not recognized any goodwill from any of our oil and natural gas property acquisitions, nor do we expect to recognize goodwill from similar business combinations that we may complete in the future.

Disclosures About Effects of Transactions with Related Parties

As of December 31, 2006, we had accrued accounts receivable from our CEO, Aubrey K. McClendon, of $11.1 million representing joint interest billings from December 2006 which were invoiced and paid in January 2007. Since Chesapeake was founded in 1989, Mr. McClendon has acquired working interests in virtually all of our oil and natural gas properties by participating in our drilling activities. Joint interest billings to him are settled in cash immediately upon delivery of a monthly joint interest billing.

Under the Founder Well Participation Program, approved by our shareholders in June 2005, Mr. McClendon (and our co-founder and former COO, Tom L. Ward prior to August 10, 2006) may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake's Board of Directors not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the Founder Well Participation Program, which, among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake's working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation. Mr. Ward's participation in the Founder Well Participation Program terminated on August 10, 2006.

As disclosed in Note 8, in 2006, Chesapeake had revenues of $867.3 million from oil and natural gas sales to Eagle Energy Partners I, L.P., an affiliated entity.

Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In December 2004, the FASB issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, *Accounting for Stock-Based Compensation*. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We adopted this statement effective January 1, 2006. The effect of SFAS 123(R) is more fully described in Note 1 of notes to the consolidated financial statements in Item 8 of this report.

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. EITF Issue No. 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We adopted this issue effective April 1, 2006. The adoption of EITF Issue No. 04-13 did not have a material impact on our financial statements.

In June 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. Based on our evaluation as of December 31, 2006, we do not expect that FIN 48 will have a material impact on our financial position, results of operations or cash flows.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments - an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. We are currently evaluating the provisions of SFAS 155 and believe that adoption will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently assessing the impact SFAS 157 and believe that adoption will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. This statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement is effective as of the end of the fiscal year ending after December 15, 2006. SFAS 158 did not have a material impact on our financial position, results of operations or cash flows.

Forward-Looking Statements

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

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

- the volatility of oil and natural gas prices,
- our level of indebtedness,
- the strength and financial resources of our competitors,
- the availability of capital on an economic basis to fund reserve replacement costs,
- our ability to replace reserves and sustain production,
- uncertainties inherent in estimating quantities of oil and natural gas reserves and projecting future rates of production and the timing of development expenditures,
- uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities,
- inability to effectively integrate and operate acquired companies and properties,
- unsuccessful exploration and development drilling,
- declines in the value of our oil and natural gas properties resulting in ceiling test write-downs,
- lower prices realized on oil and natural gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities,
- the negative effect lower oil and natural gas prices could have on our ability to borrow,
- drilling and operating risks,
- adverse effects of governmental and environmental regulation, and

- losses possible from pending or future litigation.

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

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

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2006, our oil and natural gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

- For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a “cap” limiting the counterparty’s exposure. In other words, there is no limit to Chesapeake’s exposure but there is a limit to the downside exposure of the counterparty.

- Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent natural gas basis protection swaps, which have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis natural gas protection swaps, which have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

- For call options, Chesapeake receives a cash premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. Generally, at the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap’s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural gas sales in the month of related production.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap. Changes in the value of cap-swaps and counter-swaps are recorded as adjustments to oil and natural gas sales.

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

Gains or losses from derivative transactions are reflected as adjustments to oil and natural gas sales in the consolidated statements of operations. Realized gains (losses) included in oil and natural gas sales were $1.254 billion, ($401.7) million and ($154.9) million in the 2006, 2005 and 2004, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and natural gas sales. Unrealized gains (losses) included in oil and natural gas sales were $495.5 million, $41.1 million and $40.9 million in 2006, 2005 and 2004, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales as unrealized gains (losses). We recorded an unrealized gain (loss) on ineffectiveness of $311.1 million, ($76.3) million and ($8.2) million in 2006, 2005 and 2004, respectively.

As of December 31, 2006, we had the following open oil and natural gas derivative instruments (excluding derivatives assumed through our acquisition of CNR in November 2005) designed to hedge a portion of our oil and natural gas production for periods after December 2006:

	Volume	Net Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums Received ($ in thousands)	Fair Value at December 31, 2006 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
1Q 2007	28,520,000	$ 8.34	$ —	$ —	$ —	Yes	$ —	$ 57,279
2Q 2007	3,930,000	5.55	—	—	—	Yes	—	(5,100)
3Q 2007	6,900,000	6.59	—	—	—	Yes	—	(3,060)
4Q 2007	6,900,000	7.58	—	—	—	Yes	—	(2,268)
1Q 2008	36,172,500	11.03	—	—	—	Yes	—	79,855
2Q 2008	49,822,500	8.36	—	—	—	Yes	—	42,869
3Q 2008	50,370,000	8.42	—	—	—	Yes	—	38,678
4Q 2008	50,370,000	9.03	—	—	—	Yes	—	40,266
Basis Protection Swaps (Mid-Continent):								
1Q 2007	37,350,000	—	—	—	(0.36)	No	—	10,028
2Q 2007	34,125,000	—	—	—	(0.35)	No	—	17,214
3Q 2007	34,500,000	—	—	—	(0.35)	No	—	14,814
4Q 2007	35,720,000	—	—	—	(0.32)	No	—	29,380
1Q 2008	33,215,000	—	—	—	(0.30)	No	—	31,192
2Q 2008	26,845,000	—	—	—	(0.25)	No	—	18,435
3Q 2008	27,140,000	—	—	—	(0.25)	No	—	16,385
4Q 2008	31,410,000	—	—	—	(0.28)	No	—	22,476
1Q 2009	26,100,000	—	—	—	(0.32)	No	—	16,737
2Q 2009	20,020,000	—	—	—	(0.28)	No	—	3,513
3Q 2009	20,240,000	—	—	—	(0.28)	No	—	2,818
4Q 2009	20,240,000	—	—	—	(0.28)	No	—	5,763
Basis Protection Swaps (Appalachian Basin):								
1Q 2007	9,000,000	—	—	—	0.35	No	—	(677)
2Q 2007	9,100,000	—	—	—	0.35	No	—	(554)
3Q 2007	9,200,000	—	—	—	0.35	No	—	(614)
4Q 2007	9,200,000	—	—	—	0.35	No	—	(93)
1Q 2008	9,100,000	—	—	—	0.35	No	—	706
2Q 2008	9,100,000	—	—	—	0.35	No	—	(276)
3Q 2008	9,200,000	—	—	—	0.35	No	—	(339)
4Q 2008	9,200,000	—	—	—	0.35	No	—	(35)
1Q 2009	4,500,000	—	—	—	0.31	No	—	301
2Q 2009	4,550,000	—	—	—	0.31	No	—	(95)
3Q 2009	4,600,000	—	—	—	0.31	No	—	(124)
4Q 2009	4,600,000	—	—	—	0.31	No	—	15
Cap-Swaps:								
1Q 2007	12,150,000	11.48	5.70	—	—	No	—	45,224
2Q 2007	19,110,000	9.57	5.91	—	—	No	—	17,225
3Q 2007	19,320,000	9.76	5.91	—	—	No	—	11,507
4Q 2007	19,320,000	10.56	5.91	—	—	No	—	13,003
1Q 2008	19,110,000	11.58	6.18	—	—	No	—	17,124
2Q 2008	19,110,000	10.00	6.18	—	—	No	—	7,782
3Q 2008	19,320,000	10.09	6.18	—	—	No	—	4,572
4Q 2008	19,320,000	10.65	6.18	—	—	No	—	5,429
Counter-Swaps:								
1Q 2007	(3,410,000)	(8.33)	—	—	—	No	—	(4,322)
2Q 2007	(1,375,000)	(7.73)	—	—	—	No	—	(1,133)
Call Options:								
1Q 2007	1,800,000	—	—	12.50	—	No	1,890	(11)
2Q 2007	1,820,000	—	—	12.50	—	No	1,911	(60)
3Q 2007	1,840,000	—	—	12.50	—	No	1,932	(261)
4Q 2007	1,840,000	—	—	12.50	—	No	1,932	(830)
1Q 2008	1,820,000	—	—	12.50	—	No	1,911	(1,421)
2Q 2008	1,820,000	—	—	12.50	—	No	1,911	(434)
3Q 2008	1,840,000	—	—	12.50	—	No	1,932	(682)
4Q 2008	1,840,000	—	—	12.50	—	No	1,932	(1,174)
Total Natural Gas							15,351	547,027

	Volume	Net Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums Received ($ in thousands)	Fair Value at December 31, 2006 ($ in thousands)
Oil (bbls):								
Swaps:								
1Q 2007	937,000	$ 71.01	$ —	$ —	$ —	Yes	$ —	7,668
2Q 2007	1,092,000	70.04	—	—	—	Yes	—	5,759
3Q 2007	1,104,000	69.71	—	—	—	Yes	—	3,985
4Q 2007	1,104,000	69.31	—	—	—	Yes	—	2,568
1Q 2008	1,001,000	70.44	—	—	—	Yes	—	2,979
2Q 2008	1,001,000	70.02	—	—	—	Yes	—	2,339
3Q 2008	1,012,000	69.60	—	—	—	Yes	—	1,915
4Q 2008	920,000	68.79	—	—	—	Yes	—	1,095
1Q 2009	45,000	66.64	—	—	—	Yes	—	(28)
2Q 2009	45,500	66.27	—	—	—	Yes	—	(37)
3Q 2009	46,000	65.92	—	—	—	Yes	—	(44)
4Q 2009	46,000	65.56	—	—	—	Yes	—	(50)
Cap-Swaps:								
1Q 2007	360,000	78.53	56.25	—	—	No	—	5,499
2Q 2007	364,000	78.53	56.25	—	—	No	—	4,416
3Q 2007	368,000	78.53	56.25	—	—	No	—	3,745
4Q 2007	368,000	78.53	56.25	—	—	No	—	3,249
1Q 2008	273,000	77.60	55.00	—	—	No	—	1,982
2Q 2008	273,000	77.60	55.00	—	—	No	—	1,816
3Q 2008	276,000	77.60	55.00	—	—	No	—	1,719
4Q 2008	276,000	77.60	55.00	—	—	No	—	1,631
Total Oil							—	52,206
Total Natural Gas and Oil							$ 15,351	$ 599,233

We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed do not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

The following details the assumed CNR derivatives remaining as of December 31, 2006:

	Volume	Net Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at December 31, 2006 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
1Q 2007	10,350,000	$ 4.82	$ —	$ —	Yes	$ (15,047)
2Q 2007	10,465,000	4.82	—	—	Yes	(18,834)
3Q 2007	10,580,000	4.82	—	—	Yes	(22,114)
4Q 2007	10,580,000	4.82	—	—	Yes	(30,822)
1Q 2008	9,555,000	4.68	—	—	Yes	(36,889)
2Q 2008	9,555,000	4.68	—	—	Yes	(24,796)
3Q 2008	9,660,000	4.68	—	—	Yes	(26,106)
4Q 2008	9,660,000	4.66	—	—	Yes	(31,177)
1Q 2009	4,500,000	5.18	—	—	Yes	(14,286)
2Q 2009	4,550,000	5.18	—	—	Yes	(8,209)
3Q 2009	4,600,000	5.18	—	—	Yes	(8,647)
4Q 2009	4,600,000	5.18	—	—	Yes	(10,517)
Collars:						
1Q 2009	900,000	—	4.50	6.00	Yes	(2,447)
2Q 2009	910,000	—	4.50	6.00	Yes	(1,316)
3Q 2009	920,000	—	4.50	6.00	Yes	(1,397)
4Q 2009	920,000	—	4.50	6.00	Yes	(1,762)
Total Natural Gas						$ (254,366)

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties and subsequently evaluated internally using established index prices and other sources. The actual contribution to our future results of operations will be based on the market prices at the time of settlement and may be more or less than the fair value estimates used at December 31, 2006.

Based upon the market prices at December 31, 2006, we expect to transfer approximately $282.5 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of December 31, 2006 are expected to mature by December 31, 2009.

Additional information concerning the fair value of our oil and natural gas derivative instruments, including CNR derivatives assumed, is as follows:

	December 31, 2006	2005	2004
		($ in thousands)	
Fair value of contracts outstanding, as of January 1	$ (945,814)	$ 38,350	$ (44,988)
Change in fair value of contracts during the period	3,423,099	(771,076)	(69,927)
Fair value of contracts when entered into during the period	(32,300)	(614,772)	(5,369)
Contracts realized or otherwise settled during the period	(1,253,653)	401,684	154,901
Fair value of contracts when closed during the period	(846,465)	—	3,733
Fair value of contracts outstanding, as of December 31	$ 344,867	$ (945,814)	$ 38,350

The change in the fair value of our derivative instruments since January 1, 2006 resulted from the settlement of derivatives for a realized gain, as well as a decrease in natural gas prices. Derivative instruments reflected as current in the consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and natural gas as of the consolidated balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

In 2006, Chesapeake lifted a portion of its 2007, 2008 and 2009 hedges and as a result received $744.1 million in cash from its hedging counterparties. The gain has been recorded in accumulated other comprehensive income and in oil and natural gas sales based on the designation of the hedges. For amounts initially recorded in other comprehensive income, the gain will be recognized in oil and natural gas sales in the month of the hedged production.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of December 31, 2006, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity							
	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value
	($ in billions)							
Liabilities:								
Long-term debt - fixed-rate[a]	$ —	$ —	$ —	$ —	$ —	$ 7.316	$ 7.316	$ 7.336
Average interest rate	—	—	—	—	—	6.5%	6.5%	6.5%
Long-term debt - variable rate	$ —	$ —	$ —	$ —	$ 0.178	$ —	$ 0.178	$ 0.178
Average interest rate	—	—	—	—	8.25%	—	8.25%	8.25%

(a) This amount does not include the discount included in long-term debt of ($101.9) million and the discount for interest rate swaps of ($17.0) million.

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

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from derivative transactions are reflected as adjustments to interest expense in the consolidated statements of operations. Realized gains (losses) included in interest expense were ($1.9) million, $4.9 million and $0.8 million in 2006, 2005 and 2004, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were $1.6 million, $1.6 million and ($5.3) million in 2006, 2005 and 2004, respectively.

As of December 31, 2006, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value ($ in thousands)
September 2004 – August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,695)
July 2005 – January 2015	$150,000,000	7.750%	6 month LIBOR plus 289 basis points	(5,866)
July 2005 – June 2014	$150,000,000	7.500%	6 month LIBOR plus 282 basis points	(6,133)
September 2005 – August 2014	$250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(6,807)
October 2005 – June 2015	$200,000,000	6.375%	6 month LIBOR plus 112 basis points	(2,860)
October 2005 – January 2018	$250,000,000	6.250%	6 month LIBOR plus 99 basis points	(6,334)
December 2006 – July 2013	$250,000,000	7.625%	6 month LIBOR plus 266.5 basis points	(2,755)
				$ (33,450)

In 2006, we closed six interest rate swaps for gains totaling $5.7 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes. Subsequent to December 31, 2006, we closed one interest rate swap for a gain of $1.0 million.

Subsequent to December 31, 2006, we entered into the following interest rate swaps (which qualify as fair value hedges) to convert a portion of our long-term fixed-rate debt to floating-rate debt:

Term	Notional Amount	Fixed Rate	Floating Rate
January 2007 – July 2013	$250,000,000	7.625%	6 month LIBOR plus 251 basis points
January 2007 – August 2017	$250,000,000	6.500%	6 month LIBOR plus 124.5 basis points

Additionally, subsequent to December 31, 2006, we sold call options to a counterparty with respect to these two interest rate swaps and received $3.7 million in premiums. If exercised, the call option on the 7.625% interest rate swap gives the counterparty the right to terminate the interest rate swap on July 12, 2007 for a payment to Chesapeake of $2.0 million. The call option on the 6.50% interest rate swap gives the counterparty the right to terminate the interest rate swap on August 15, 2007 for a payment of $2.0 million to Chesapeake.

Foreign Currency Derivatives

On December 5, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties will pay Chesapeake €18.75 million and Chesapeake will pay the counterparties $29.95 million, which will yield an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €600 million and Chesapeake will pay the counterparties $799.5 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($791.8 million at December 31, 2006) using an exchange rate of $1.3197 to €1.00. The cross currency swap is recorded on the consolidated balance sheet at a fair value of ($18.9) million at December 31, 2006. The translation adjustment to notes payable is completely offset by the fair value of the cross currency swap and therefore there is no impact to the consolidated statement of operations. The remaining value of the cross currency swap related to future interest payments is reported in other comprehensive income.

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

INDEX TO FINANCIAL STATEMENTS

CHESAPEAKE ENERGY CORPORATION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of the management of Chesapeake Energy Corporation to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management utilized the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control–Integrated Framework* (COSO framework) in conducting the required assessment of effectiveness of the Company's internal control over financial reporting.

Management has performed an assessment of the effectiveness of the Company's internal control over financial reporting and has determined the Company's internal control over financial reporting was effective as of December 31, 2006.

Our management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

Aubrey K. McClendon
Chairman and Chief Executive Officer

Marcus C. Rowland
Executive Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Chesapeake Energy Corporation:

We have completed integrated audits of Chesapeake Energy Corporation's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing in Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control - Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Tulsa, Oklahoma
February 28, 2007

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,519	$ 60,027
Accounts receivable	844,851	791,194
Deferred income taxes	—	234,592
Short-term derivative instruments	224,996	10,503
Inventory and other	81,503	87,081
Total Current Assets	1,153,869	1,183,397
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full-cost accounting:		
Evaluated oil and natural gas properties	21,949,295	15,880,919
Unevaluated properties	3,796,405	1,739,095
Less: accumulated depreciation, depletion and amortization of oil and natural gas properties	(5,291,846)	(3,945,703)
Total oil and natural gas properties, at cost based on full-cost accounting	20,453,854	13,674,311
Other property and equipment:		
Natural gas gathering systems	552,608	333,365
Drilling rigs	300,810	116,133
Buildings and land	428,692	233,467
Natural gas compressors	126,806	73,043
Other	241,092	110,208
Less: accumulated depreciation and amortization of other property and equipment	(199,819)	(128,640)
Total Property and Equipment	21,904,043	14,411,887
OTHER ASSETS:		
Investments	698,962	297,443
Long-term derivative instruments	339,474	78,860
Other assets	320,819	146,875
Total Other Assets	1,359,255	523,178
TOTAL ASSETS	$24,417,167	$16,118,462

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	($ in thousands)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 859,745	$ 516,792
Short-term derivative instruments	111,649	577,681
Accrued liabilities	419,361	364,501
Deferred income taxes	38,484	—
Revenues and royalties due others	318,303	394,693
Accrued interest	142,267	110,421
Total Current Liabilities	1,889,809	1,964,088
LONG-TERM LIABILITIES:		
Long-term debt, net	7,375,548	5,489,742
Deferred income tax liability	3,317,459	1,804,978
Asset retirement obligation	192,772	156,593
Long-term derivative instruments	160,283	479,996
Revenues and royalties due others	29,711	22,585
Other liabilities	200,114	26,157
Total Long-Term Liabilities	11,275,887	7,980,051
CONTINGENCIES AND COMMITMENTS (Note 4)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
6.00% cumulative convertible preferred stock, 0 and 99,310 shares issued and outstanding as of December 31, 2006 and 2005, respectively, entitled in liquidation to $0 and $4,965,500	—	4,966
5.00% cumulative convertible preferred stock (Series 2003), 0 and 1,025,946 shares issued and outstanding as of December 31, 2006 and 2005, respectively, entitled in liquidation to $0 and $102,594,600	—	102,595
4.125% cumulative convertible preferred stock, 3,065 and 89,060 shares issued and outstanding as of December 31, 2006 and 2005, respectively, entitled in liquidation to $3,065,000 and $89,060,000	3,065	89,060
5.00% cumulative convertible preferred stock (Series 2005), 4,600,000 shares issued and outstanding as of December 31, 2006 and 2005, entitled in liquidation to $460,000,000	460,000	460,000
4.50% cumulative convertible preferred stock, 3,450,000 shares issued and outstanding as of December 31, 2006 and 2005, entitled in liquidation to $345,000,000	345,000	345,000
5.00% cumulative convertible preferred stock (Series 2005B), 5,750,000 shares issued and outstanding as of December 31, 2006 and 2005, entitled in liquidation to $575,000,000	575,000	575,000
6.25% mandatory convertible preferred stock, 2,300,000 and 0 shares issued and outstanding as of December 31, 2006 and 2005, respectively, entitled in liquidation to $575,000,000 and $0	575,000	—
Common Stock, $.01 par value, 750,000,000 and 500,000,000 shares authorized, 458,600,789 and 375,510,521 shares issued December 31, 2006 and 2005, respectively	4,586	3,755
Paid-in capital	5,873,080	3,803,312
Retained earnings	2,913,722	1,100,841
Accumulated other comprehensive income (loss), net of tax of ($318,889,000) and $112,071,000, respectively	528,321	(194,972)
Unearned compensation	—	(89,242)
Less: treasury stock, at cost; 1,167,007 and 5,320,816 common shares as of December 31, 2006 and 2005, respectively	(26,303)	(25,992)
Total Stockholders' Equity	11,251,471	6,174,323
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$24,417,167	$16,118,462

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31, 2006	2005	2004
	($ in thousands, except per share data)		
REVENUES:			
Oil and natural gas sales	$ 5,618,894	$ 3,272,585	$ 1,936,176
Oil and natural gas marketing sales	1,576,391	1,392,705	773,092
Service operations revenue	130,310	—	—
Total Revenues	7,325,595	4,665,290	2,709,268
OPERATING COSTS:			
Production expenses	489,499	316,956	204,821
Production taxes	176,440	207,898	103,931
General and administrative expenses	139,152	64,272	37,045
Oil and natural gas marketing expenses	1,521,848	1,358,003	755,314
Service operations expense	67,922	—	—
Oil and natural gas depreciation, depletion and amortization	1,358,519	894,035	582,137
Depreciation and amortization of other assets	104,240	50,966	29,185
Employee retirement expense	54,753	—	—
Provision for legal settlements	—	—	4,500
Total Operating Costs	3,912,373	2,892,130	1,716,933
INCOME FROM OPERATIONS	3,413,222	1,773,160	992,335
OTHER INCOME (EXPENSE):			
Interest and other income	25,463	10,452	4,476
Interest expense	(300,722)	(219,800)	(167,328)
Gain on sale of investment	117,396	—	—
Loss on repurchases or exchanges of Chesapeake senior notes	—	(70,419)	(24,557)
Total Other Income (Expense)	(157,863)	(279,767)	(187,409)
INCOME BEFORE INCOME TAXES	3,255,359	1,493,393	804,926
INCOME TAX EXPENSE:			
Current	5,000	—	—
Deferred	1,247,036	545,091	289,771
Total Income Tax Expense	1,252,036	545,091	289,771
NET INCOME	2,003,323	948,302	515,155
PREFERRED STOCK DIVIDENDS	(88,645)	(41,813)	(39,506)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(10,556)	(26,874)	(36,678)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 1,904,122	$ 879,615	$ 438,971
EARNINGS PER COMMON SHARE:			
Basic	$ 4.78	$ 2.73	$ 1.73
Assuming dilution	$ 4.35	$ 2.51	$ 1.53
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.23	$ 0.195	$ 0.17
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):			
Basic	398,487	322,034	253,212
Assuming dilution	458,603	366,683	305,718

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2006	2005	2004
	($ in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME	$ 2,003,323	$ 948,302	$ 515,155
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion, and amortization	1,449,442	935,965	605,593
Deferred income taxes	1,251,742	544,891	289,532
Unrealized (gains) losses on derivatives	(497,124)	(42,722)	(35,549)
Amortization of loan costs and bond discount	20,629	14,784	10,275
Realized (gains) losses on financing derivatives	(136,441)	(226)	—
Stock-based compensation	84,483	15,343	4,828
Gain on sale of investment in Pioneer Drilling Company	(117,396)	—	—
Income from equity investments	(9,966)	—	—
Loss on repurchases or exchanges of Chesapeake senior notes	—	70,419	24,557
Premiums paid for repurchasing of senior notes	—	(59,893)	(16,281)
Other	(3,583)	(1,136)	4,412
(Increase) decrease in accounts receivable	(21,634)	(204,860)	(152,590)
(Increase) decrease in inventory and other assets	(126,541)	(66,979)	(9,481)
Increase (decrease) in accounts payable, accrued liabilities and other	1,020,697	92,215	97,635
Increase (decrease) in current and non-current revenues and royalties due others	(74,157)	160,785	94,188
Cash provided by operating activities	4,843,474	2,406,888	1,432,274
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of oil and natural gas companies, proved and unproved properties, net of cash acquired	(3,960,094)	(4,134,782)	(2,054,673)
Exploration and development of oil and natural gas properties	(3,779,233)	(2,162,545)	(1,136,414)
Additions to buildings and other fixed assets	(593,715)	(417,470)	(126,707)
Additions to drilling rig equipment	(392,664)	(66,758)	(23,093)
Additions to investments	(554,591)	(135,013)	(36,962)
Acquisition of trucking company, net of cash acquired	(45,166)	—	—
Proceeds from sale of investment in Pioneer Drilling Company	158,890	—	—
Proceeds from sale of drilling rigs and equipment	243,615	—	—
Deposits for acquisitions	(21,700)	(35,000)	(16,250)
Divestitures of oil and natural gas properties	118	9,769	12,048
Sale of non-oil and natural gas assets and investments	1,902	20,422	860
Other	139	(1)	(13)
Cash used in investing activities	(8,942,499)	(6,921,378)	(3,381,204)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	8,370,000	5,682,000	2,160,000
Payments on long-term borrowings	(8,264,000)	(5,765,116)	(2,101,000)
Proceeds from issuance of senior notes, net of offering costs	1,754,846	2,924,636	1,165,975
Proceeds from issuance of common stock, net of offering costs	1,758,976	985,782	624,187
Proceeds from issuance of preferred stock, net of offering costs	557,627	1,341,529	304,936
Cash paid to purchase or exchange Chesapeake senior notes	—	(565,868)	(248,434)
Cash paid for common stock dividends	(87,008)	(60,528)	(38,902)
Cash paid for preferred stock dividends	(88,424)	(31,480)	(40,907)
Cash paid for financing cost of credit facilities	(5,496)	(4,672)	(9,175)
Cash paid for treasury stock	(86,185)	(4,000)	—
Derivative settlements	(86,923)	(11,642)	—
Net increase in outstanding payments in excess of cash balance	69,998	61,171	88,348
Cash received from exercise of stock options and warrants	73,172	21,612	11,987
Excess tax benefit from stock-based compensation	87,569	—	—
Other financing costs	(12,635)	(5,803)	(1,770)
Cash provided by financing activities	4,041,517	4,567,621	1,915,245
Net increase (decrease) in cash and cash equivalents	(57,508)	53,131	(33,685)
Cash and cash equivalents, beginning of period	60,027	6,896	40,581
Cash and cash equivalents, end of period	$ 2,519	$ 60,027	$ 6,896

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

	Years Ended December 31,		
	2006	2005	2004
		($ in thousands)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$ 272,956	$ 175,416	$ 134,000
Income taxes, net of refunds received	$ 294	$ 200	$ 239

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of December 31, 2006, 2005 and 2004, dividends payable on our common and preferred stock were $52.9 million, $37.9 million and $19.4 million, respectively.

In 2006, 2005 and 2004, oil and natural gas properties were adjusted by $179.7 million, $251.7 million and $463.9 million, respectively, for net income tax liabilities related to acquisitions.

During 2006, 2005 and 2004, accrued exploration and development costs of $84.7 million, $27.3 million and $29.7 million, respectively, were recorded as additions to oil and natural gas properties.

We recorded non-cash asset additions to net oil and natural gas properties of $23.2 million, $76.8 million and $20.2 million in 2006, 2005 and 2004, respectively, for asset retirement obligations.

In 2006, holders of our 5% (Series 2003) and 6% cumulative convertible preferred stock converted 38,625 shares and 99,310 shares into 235,447 shares and 482,694 shares of common stock at a conversion price of $16.405 per share and $10.287 per share, respectively.

In 2006, holders of our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock exchanged 83,245 shares and 804,048 shares for 5,248,126 and 4,972,786 shares of common stock, respectively, in public exchange offers.

In 2006, holders of our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock converted 2,750 shares and 183,273 shares into 172,594 shares and 1,140,223 shares of common stock, respectively, in privately negotiated exchanges.

In 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for $240 million in cash and 1,375,989 newly issued shares of our common stock valued at $40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma.

In 2005, holders of our 6.0% cumulative convertible preferred stock converted 3,800 shares into 18,468 shares of common stock at a conversion price of $10.287 per share.

In 2005, holders of our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock exchanged 224,190 and 699,054 shares for 14,321,881 and 4,362,720 shares, respectively, of common stock in privately negotiated exchanges.

In 2005, Chesapeake acquired Columbia Energy Resources, LLC and its subsidiaries, including Columbia Natural Resources, LLC ("CNR"), for a total consideration of $3.02 billion, consisting of $2.2 billion of cash and derivative liabilities, prepaid sales agreements and other liabilities of $0.8 billion. See further discussion regarding the CNR acquisition in Note 13 of the notes to our consolidated financial statements.

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

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

In 2004, holders of our 6.75% cumulative convertible preferred stock converted 2,998,000 shares into 19,467,482 shares of common stock at a conversion price of $7.70 per share.

In 2004, holders of our 6.0% cumulative convertible preferred stock exchanged 600,000 shares for 3,225,000 shares of common stock and 3,896,890 shares for 20,754,817 shares of common stock in a privately negotiated exchange and a public exchange offer, respectively.

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

In 2004, Chesapeake acquired Hallwood Energy Corporation for a total consideration of $292.0 million, consisting of $223.5 million of cash and short-term notes payable of $60.0 million.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Years Ended December 31,		
	2006	2005	2004
		($ in thousands)	
PREFERRED STOCK:			
Balance, beginning of period	$ 1,576,621	$ 490,906	$ 552,400
Issuance of 6.25% mandatory convertible preferred stock	575,000	—	—
Issuance of 5.00% cumulative convertible preferred stock (Series 2005)	—	460,000	—
Issuance of 4.50% cumulative convertible preferred stock	—	345,000	—
Issuance of 5.00% cumulative convertible preferred stock (Series 2005B)	—	575,000	—
Issuance of 4.125% cumulative convertible preferred stock	—	—	313,250
Exchange of common stock for 85,995 and 224,190 shares of 4.125% preferred stock	(85,995)	(224,190)	—
Exchange of common stock for 1,025,946 and 699,054 shares of 5.00% preferred stock (Series 2003)	(102,595)	(69,905)	—
Exchange of common stock for 99,310, 3,800 and 4,496,890 shares of 6.00% preferred stock	(4,966)	(190)	(224,844)
Exchange of common stock for 2,998,000 shares of 6.75% preferred stock	—	—	(149,900)
Balance, end of period	1,958,065	1,576,621	490,906
COMMON STOCK:			
Balance, beginning of period	3,755	3,169	2,218
Issuance of 58,750,000, 32,200,000 and 46,000,000 shares of common stock	588	322	460
Issuance of 1,375,989 shares of common stock for the purchase of Chaparral Energy, Inc. common stock	14	—	—
Exchange of 12,251,870, 18,703,069 and 43,447,299 shares of common stock for preferred stock	122	187	435
Exercise of stock options and warrants	70	40	29
Restricted stock grants	37	37	27
Balance, end of period	4,586	3,755	3,169
PAID-IN CAPITAL:			
Balance, beginning of period	3,803,312	2,440,105	1,389,212
Issuance of common stock	1,799,100	1,024,282	649,520
Issuance of common stock for the purchase of Chaparral Energy, Inc. common stock	39,986	—	—
Exchange of 12,251,870, 18,703,069 and 43,447,299 shares of common stock for preferred stock	193,432	294,098	374,310
Equity-based compensation	99,617	82,144	41,485
Adoption of SFAS 123(R)	(89,242)	—	—
Offering expenses	(58,082)	(77,293)	(34,297)
Exercise of stock options and warrants	73,102	21,573	11,958
Release of 6,500,000 shares from treasury stock upon exercise of stock options	(75,102)	—	—
Tax benefit from exercise of stock options and restricted stock	87,569	18,506	9,135
Preferred stock conversion/exchange expenses	(612)	(103)	(1,218)
Balance, end of period	5,873,080	3,803,312	2,440,105
RETAINED EARNINGS (DEFICIT):			
Balance, beginning of period	1,100,841	262,987	(168,617)
Net income	2,003,323	948,302	515,155
Dividends on common stock	(95,809)	(64,830)	(45,229)
Dividends on preferred stock	(94,633)	(45,618)	(38,322)
Balance, end of period	2,913,722	1,100,841	262,987
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(194,972)	20,425	(20,312)
Hedging activity	809,534	(266,312)	15,946
Marketable securities activity	(86,241)	50,915	24,791
Balance, end of period	528,321	(194,972)	20,425
UNEARNED COMPENSATION:			
Balance, beginning of period	(89,242)	(32,618)	—
Restricted stock granted	—	(79,979)	(38,949)
Amortization of unearned compensation	—	23,355	6,331
Adoption of SFAS 123(R)	89,242	—	—
Balance, end of period	—	(89,242)	(32,618)
TREASURY STOCK—COMMON:			
Balance, beginning of period	(25,992)	(22,091)	(22,091)
Purchase of 2,707,471 and 257,220 shares of treasury stock	(86,185)	(4,000)	—
Release of 6,500,000 shares upon exercise of stock options	75,102	—	—
Release of 361,280 shares and 8,525 shares for company benefit plans	10,772	99	—
Balance, end of period	(26,303)	(25,992)	(22,091)
TOTAL STOCKHOLDERS' EQUITY	$11,251,471	$ 6,174,323	$ 3,162,883

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2006	2005	2004
		($ in thousands)	
Net Income	$ 2,003,323	$ 948,302	$ 515,155
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of $1,032,500,000, ($317,772,000) and ($44,463,000), respectively	1,711,196	(552,837)	(79,046)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($426,455,000), $136,841,000 and $50,480,000, respectively	(706,615)	238,066	89,743
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($116,009,000), $27,850,000 and $2,953,000, respectively	(195,047)	48,452	5,249
Unrealized gain on marketable securities, net of income taxes of ($7,826,000), $29,266,000 and $13,945,000, respectively	(13,155)	50,915	24,791
Reclassification of gain on sales of investments, net of income taxes of ($45,824,000), $0 and $0, respectively	(73,086)	—	—
Other adjustments, net of income taxes of $3,000	—	6	—
Comprehensive income	$ 2,726,616	$ 732,904	$ 555,892

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

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation ("Chesapeake" or the "company") is an oil and natural gas exploration and production company engaged in the acquisition, exploration and development of properties for the production of crude oil and natural gas from underground reservoirs and the marketing of natural gas and oil for other working interest owners in properties we operate. Our properties are located in Oklahoma, Texas, Alabama, Arkansas, Louisiana, Kansas, Montana, Colorado, North Dakota, Nebraska, New Mexico, West Virginia, Kentucky, Ohio, New York, Maryland, Michigan, Mississippi, Pennsylvania, Tennessee, Utah, Virginia and Wyoming.

Principles of Consolidation

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

Accounting Estimates

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

Cash Equivalents

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

Accounts Receivable

Our accounts receivable are primarily from purchasers of oil and natural gas and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

Accounts receivable consists of the following components:

	December 31,	
	2006	2005
	($ in thousands)	
Oil and natural gas sales	$ 617,780	$ 615,382
Joint interest	135,348	89,669
Service operations	16,855	3
Related parties	12,158	12,839
Other	68,258	78,205
Allowance for doubtful accounts	(5,548)	(4,904)
Total accounts receivable	$ 844,851	$ 791,194

Inventory

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

Oil and Natural Gas Properties

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities (see Note 11). Capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. As of December 31, 2006, approximately 80% of our proved reserves were evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers evaluate all properties on an annual basis. The average composite rates used for depreciation, depletion and amortization were $2.35 per mcfe in 2006, $1.91 per mcfe in 2005 and $1.61 per mcfe in 2004.

Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized.

The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties and otherwise if impairment has occurred. Unevaluated properties are grouped by major prospect area where individual property costs are not significant and are assessed individually when individual costs are significant.

We review the carrying value of our oil and natural gas properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

We account for seismic costs in accordance with Rule 4-10 of Regulation S-X. Specifically, Rule 4-10 requires that all companies that use the full-cost method capitalize exploration costs as part of their oil and natural gas properties (i.e., full-cost pool). Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Further, exploration costs include, among other things, geological and geophysical studies and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Such costs are capitalized as incurred. Seismic costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties. The company reviews its unproved properties and associated seismic costs quarterly in order to ascertain whether impairment has incurred. To the extent that seismic costs cannot be directly associated with specific unevaluated properties, they are included in the amortization base as incurred.

Other Property and Equipment

Other property and equipment consists primarily of natural gas gathering and processing facilities, drilling rigs, land, buildings and improvements, natural gas compressors, vehicles, office equipment, and software. Land purchases are made in order to build additional office space at our Oklahoma City headquarters and additional offices in various states. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. The costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from the accounts, and the resulting gain or loss is reflected in operations. Other property and equipment costs are depreciated on a straight-line basis. A summary of other property and equipment and the useful lives are as follows:

	December 31		
	2006	2005	Useful Life
	($ in thousands)		(in years)
Natural gas gathering systems	$ 552,608	$ 333,365	7 - 20
Buildings and improvements	304,959	159,001	15 - 39
Drilling rigs	300,810	116,133	15
Other fixtures and equipment	241,092	110,208	2 - 7
Natural gas compressors	126,806	73,043	15
Land	123,733	74,466	—
Total	$ 1,650,008	$ 866,216	

Investments

Investments in securities are accounted for under the equity method in circumstances where we are deemed to exercise significant influence over the operating and investing policies of the investee. Under the equity method, we recognize our share of the investee's earnings in our consolidated statements of operations. Investments in securities not accounted for under the equity method are accounted for under the cost method. Investments in marketable equity securities accounted for under the cost method have been designated as available for sale and, as such, are recorded at fair value. We have no investments which are required to be consolidated pursuant to the terms of FASB Interpretation No. (FIN) 46, *Consolidation of Variable Interest Entities*.

At December 31, 2006, investments accounted for under the equity method totaled $627.9 million and investments accounted for under the cost method totaled $71.1 million. Following is a summary of our investments:

			December 31,	
			2006	2005
	Approximate % Owned	Accounting Method	Carrying Value	Carrying Value
			($ in thousands)	
Chaparral Energy, Inc.	32%	Equity	$ 280,000	$ —
Frac Tech Services, Ltd	20%	Equity	254,000	—
Gastar Exploration Ltd[(a)]	17%	Cost	69,126	98,425
Eagle Energy Partners I, L.P.	33%	Equity	36,451	7,912
DHS Drilling Company	45%	Equity	25,770	15,245
Mountain Drilling Company	49%	Equity	23,587	27,609
Pioneer Drilling Company[(b)]	17%	Cost	—	138,095
Other	—	—	10,028	10,157
			$ 698,962	$ 297,443

(a) Our investment in Gastar had an associated cost basis of $86.0 million and $76.0 million as of December 31, 2006 and 2005, respectively.
(b) Our investment in Pioneer had an associated cost basis of $42.7 million as of December 31, 2005.

Capitalized Interest

During 2006, 2005 and 2004, interest of approximately $179.1 million, $79.0 million and $36.2 million, respectively, was capitalized on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings.

Accounts Payable and Accrued Liabilities

Included in accounts payable at December 31, 2006 and 2005, respectively, are liabilities of approximately $247.8 million and $177.8 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Other accrued liabilities include $176.7 million and $88.3 million of accrued drilling costs as of December 31, 2006 and 2005, respectively.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and costs associated with our revolving bank credit facility. The remaining unamortized debt issue costs at December 31, 2006 and 2005 totaled $116.0 million and $92.2 million, respectively, and are being amortized over the life of the senior notes or revolving credit facility.

Asset Retirement Obligations

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

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

Revenue Recognition

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

Natural Gas Imbalances. We follow the “sales method” of accounting for our natural gas revenue whereby we recognize sales revenue on all natural gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining natural gas reserves on the underlying properties. The natural gas imbalance net position at December 31, 2006 and 2005 was a liability of $4.7 million and $4.5 million, respectively.

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

Hedging

From time to time, Chesapeake uses commodity price and financial risk management instruments to mitigate our exposure to price fluctuations in oil and natural gas transactions and interest rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of oil and natural gas derivative transactions are reflected in oil and natural gas sales and results of interest rate hedging transactions are reflected in interest expense. The changes in fair value of derivative instruments not qualifying for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within oil and natural gas sales or interest expense. Cash flows from derivative instruments are classified in the same category within the statement of cash flows as the items being hedged.

We have established the fair value of all derivative instruments using estimates determined by our counterparties and subsequently evaluated internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in oil and natural gas sales. For derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings.

Stock-Based Compensation

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment* (SFAS 123(R)), to account for stock-based compensation. Among other items, SFAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the fair value at grant date of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Upon adoption of SFAS 123(R), we elected to use the "short-cut" method to calculate the historical pool of windfall tax benefits in accordance with Financial Accounting Standards Board Staff Position No. FAS 123(R)-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, issued on November 10, 2005. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense based on the fair value on the date of grant or modification will be recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. To the extent compensation cost relates to employees directly involved in oil and natural gas exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expenses or production expenses.

Prior to the adoption of SFAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated. Upon adoption of SFAS 123(R), we eliminated $89.2 million of unearned compensation cost and reduced additional paid-in capital by the same amount on our consolidated balance sheet.

For the years ended December 31, 2006, 2005 and 2004, we recorded the following stock-based compensation ($ in thousands):

	Restricted Stock	Stock Options	Total
For the Year Ended December 31, 2006:			
Production expenses	$ 5,926	$ 664	$ 6,590
General and administrative expenses	22,989	3,672	26,661
Employee retirement expense	35,720	15,510	51,230
Oil and natural gas properties	21,058	2,214	23,272
Total	$ 85,693	$ 22,060	$ 107,753
For the Year Ended December 31, 2005:			
Production expenses	$ —	$ —	$ —
General and administrative expenses	12,759	2,584	15,343
Oil and natural gas properties	10,735	1,158	11,893
Total	$ 23,494	$ 3,742	$ 27,236
For the Year Ended December 31, 2004:			
Production expenses	$ —	$ —	$ —
General and administrative expenses	4,243	585	4,828
Oil and natural gas properties	2,088	—	2,088
Total	$ 6,331	$ 585	$ 6,916

SFAS 123 (R) generally did not change the accounting for awards of restricted stock. The impact to income before income taxes of adopting SFAS 123(R) for 2006 was a reduction of $3.1 million associated with stock option awards. SFAS 123(R) also requires cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock (“excess tax benefits”) to be classified as financing cash inflows in our statements of cash flows. Accordingly, for the year ended December 31, 2006, we reported $87.6 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

Pro forma Disclosures

Prior to January 1, 2006, we accounted for our employee and non-employee director stock options using the intrinsic value method prescribed by APB 25. As required by SFAS 123(R), we have disclosed below the effect on net income and earnings per share that would have been recorded using the fair value based method for 2005 and 2004 ($ in thousands, except per share amounts):

	Years Ended December 31,	
	2005	2004
Net Income:		
As reported	$ 948,302	$ 515,155
Add: Stock-based compensation expense included in reported net income, net of income tax	9,743	3,090
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of income tax	(18,028)	(14,289)
Pro forma net income	$ 940,017	$ 503,956
Basic earnings per common share:		
As reported	$ 2.73	$ 1.73
Pro forma	$ 2.71	$ 1.69
Diluted earnings per common share:		
As reported	$ 2.51	$ 1.53
Pro forma	$ 2.48	$ 1.49

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2005 and 2004 to conform to the presentation used for the 2006 consolidated financial statements.

2. Net Income Per Share

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

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

- For the years ended December 31, 2005 and 2004, outstanding options to purchase 0.1 million shares of common stock at a weighted-average exercise price of $29.85 and $23.82, respectively, were antidilutive because the exercise prices of the options were greater than the average market price of the common stock.
- For the year ended December 31, 2006 and 2005, diluted shares do not include the common stock equivalent of our 4.125% preferred stock outstanding prior to conversion (convertible into 2,090,292 and 8,610,708 shares, respectively) and the preferred stock adjustments to net income do not include $9.1 million and $28.9 million, respectively, of dividends and loss on conversion/exchange related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.
- For the year ended December 31, 2004, diluted shares do not include the common stock equivalent of the 6% preferred stock outstanding prior to conversion (convertible into 21,339,375 shares) and the preferred stock adjustment to net income does not include $12.2 million of dividends related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

Emerging Issues Task Force (EITF) Issue 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings Per Share*, which was issued in September 2004, provides guidance on when the dilutive effect of contingently convertible securities with a market price trigger should be included in diluted EPS. EITF 04-8 states that these securities should be included in the diluted EPS computation regardless of whether the market price trigger has been met. The guidance in EITF 04-8 is effective for all periods ending after December 15, 2004 and has been applied retrospectively by restating previously reported EPS. Accordingly, effective December 15, 2004, the company assumed the conversion of the 4.125% convertible preferred shares issued in 2004 (if dilutive) for purposes of determining EPS assuming dilution.

A reconciliation for the years ended December 31, 2006, 2005 and 2004 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Year ended December 31, 2006:			
Basic EPS:			
Income available to common shareholders	$ 1,904,122	398,487	$ 4.78
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock	—	184	
Common shares assumed issued for 4.50% convertible preferred stock	—	7,811	
Common shares assumed issued for 5.00% (Series 2005) convertible preferred stock	—	17,856	
Common shares assumed issued for 5.00% (Series 2005B) convertible preferred stock	—	14,717	
Common shares assumed issued for 6.25% mandatory convertible preferred stock	—	9,217	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion,			
5.00% (Series 2003) convertible preferred stock	—	2,308	
6.00% convertible preferred stock	—	103	
Employee stock options	—	6,043	
Restricted stock	—	1,877	
Loss on redemption of preferred stock	2,886	—	
Preferred stock dividends	87,214	—	
Diluted EPS Income available to common shareholders and assumed conversions	$ 1,994,222	458,603	$ 4.35
For the Year ended December 31, 2005:			
Basic EPS:			
Income available to common shareholders	$ 879,615	322,034	$ 2.73
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock	—	5,349	
Common shares assumed issued for 4.50% convertible preferred stock	—	2,332	
Common shares assumed issued for 5.00% (Series 2003) convertible preferred stock	—	6,254	
Common shares assumed issued for 5.00% (Series 2005) convertible preferred stock	—	12,532	
Common shares assumed issued for 5.00% (Series 2005B) convertible preferred stock	—	2,177	
Common shares assumed issued for 6.00% convertible preferred stock	—	483	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion,			
5.00% (Series 2003) convertible preferred stock	—	3,024	
6.00% convertible preferred stock	—	12	
Employee stock options	—	10,861	
Restricted stock	—	1,614	
Warrants assumed in Gothic acquisition	—	11	
Loss on redemption of preferred stock	3,519	—	
Preferred stock dividends	36,278	—	
Diluted EPS Income available to common shareholders and assumed conversions	$ 919,412	366,683	$ 2.51
For the Year ended December 31, 2004:			
Basic EPS:			
Income available to common shareholders	$ 438,971	253,212	$ 1.73
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock	—	14,200	
Common shares assumed issued for 5.00% (Series 2003) convertible preferred stock	—	10,516	
Common shares assumed issued for 6.00% convertible preferred stock	—	501	
Common shares assumed issued for 6.75% convertible preferred stock	—	16,971	
Employee stock options	—	10,097	
Restricted stock	—	203	
Warrants assumed in Gothic acquisition	—	18	
Preferred stock dividends	27,290	—	
Diluted EPS Income available to common shareholders and assumed conversions	$ 466,261	305,718	$ 1.53

3. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following at December 31, 2006 and 2005:

	December 31, 2006	December 31, 2005
	($ in thousands)	
7.5% Senior Notes due 2013	$ 363,823	$ 363,823
7.625% Senior Notes due 2013	500,000	—
7.0% Senior Notes due 2014	300,000	300,000
7.5% Senior Notes due 2014	300,000	300,000
7.75% Senior Notes due 2015	300,408	300,408
6.375% Senior Notes due 2015	600,000	600,000
6.625% Senior Notes due 2016	600,000	600,000
6.875% Senior Notes due 2016	670,437	670,437
6.5% Senior Notes due 2017	1,100,000	600,000
6.25% Euro-denominated Senior Notes due 2017 [(a)]	791,820	—
6.25% Senior Notes due 2018	600,000	600,000
6.875% Senior Notes due 2020	500,000	500,000
2.75% Contingent Convertible Senior Notes due 2035[(b)]	690,000	690,000
Revolving bank credit facility	178,000	72,000
Discount on senior notes	(101,935)	(95,577)
Discount for interest rate derivatives[(c)]	(17,005)	(11,349)
Total notes payable and long-term debt	$ 7,375,548	$ 5,489,742

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3197 to €1.00 as of December 31, 2006. See Note 10 for information on our related cross currency swap.
(b) The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030, or upon a fundamental change, at 100% of the principal amount of these notes. The notes are convertible, at the holder's option, prior to maturity under certain circumstances, into cash and, if applicable, shares of our common stock using a net share settlement process. In general, upon conversion of a convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note's conversion value in excess of such principal amount. In addition, we will pay contingent interest on the convertible senior notes, beginning with the nine-month period ending May 14, 2016, under certain conditions. We may redeem the convertible senior notes on or after November 15, 2015 at a redemption price of 100% of the principal amount of such notes.
(c) See Note 10 for further discussion related to these instruments.

There were no repurchases or exchanges of Chesapeake debt in 2006. The following table sets forth the losses we incurred in connection with repurchases and exchanges of senior notes in 2005 and 2004:

	Notes Retired	Loss on Repurchases/Exchanges: Premium	Other[(a)]	Total
For the Year Ended December 31, 2005:				
8.375% Senior Notes due 2008	$ 19.0	$ 1.2	$ 0.1	$ 1.3
8.125% Senior Notes due 2011	245.4	17.3	4.4	21.7
9.0% Senior Notes due 2012	300.0	41.4	6.0	47.4
	$ 564.4	$ 59.9	$ 10.5	$ 70.4
For the Year Ended December 31, 2004:				
8.375% Senior Notes due 2008	$ 190.8	$ 16.1	$ 1.5	$ 17.6
8.5% Senior Notes due 2012	4.3	0.2	0.7	0.9
8.125% Senior Notes due 2011	482.8	—	6.0	6.0
	$ 677.9	$ 16.3	$ 8.2	$ 24.5

(a) Includes the write-off of unamortized discounts, deferred charges, transaction costs and derivative charges as described below.

Our outstanding senior notes are unsecured senior obligations of Chesapeake that rank equally in right of payment with all of our existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. We may redeem the senior notes, other than the 2.75% Contingent Convertible Senior Notes due 2035, at any time at specified make-whole or redemption prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries' ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale-leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our guarantor subsidiaries' ability to incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes have been fully and unconditionally guaranteed, jointly and severally, by all of our wholly owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis.

We have a $2.5 billion syndicated revolving bank credit facility which matures in February 2011. The credit facility was increased from $1.25 billion to $2.0 billion in February 2006 and to $2.5 billion in September 2006. As of December 31, 2006, we had $178.0 million in outstanding borrowings under our facility and utilized $6.2 million of the facility for various letters of credit. Borrowings under our facility are collateralized by certain producing oil and natural gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A. or the federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently, the commitment fee rate is 0.25% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which govern our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.40 to 1 and our indebtedness to EBITDA ratio was 1.64 to 1 at December 31, 2006. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility. The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly owned subsidiaries except minor subsidiaries.

4. Contingencies and Commitments

Litigation. We are involved in various disputes incidental to our business operations, including claims from royalty owners regarding volume measurements, post-production costs and prices for royalty calculations. In *Tawney, et al. v. Columbia Natural Resources, Inc.*, Chesapeake's wholly owned subsidiary Chesapeake Appalachia, L.L.C., formerly known as Columbia Natural Resources, LLC (CNR), is a defendant in a class action lawsuit in the Circuit Court of Roane County, West Virginia filed in 2003 by royalty owners. The plaintiffs allege that CNR underpaid royalties by improperly deducting post-production costs, failing to pay royalty on total volumes of natural gas produced and not paying a fair value for the natural gas produced from their leases. The plaintiff class consists of West Virginia royalty owners receiving royalties after July 31, 1990 from CNR. Chesapeake acquired CNR in November 2005, and its seller acquired CNR in 2003 from NiSource Inc. NiSource, a co-defendant in the case, has managed the litigation and indemnified Chesapeake against underpayment claims based on the use of fixed prices for natural gas production sold under certain forward sale contracts and other claims with respect to CNR's operations prior to September 2003.

On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of $404 million, consisting of $134 million in compensatory damages and $270 million in punitive damages. Most of the damages awarded by the jury relate to issues not yet addressed by the West Virginia Supreme Court of Appeals, although in June 2006 that Court ruled against the defendants on two certified questions regarding the deductibility of post-production expenses. The jury found fraud with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions.

Chesapeake and NiSource maintain CNR acted in good faith and paid royalties in accordance with lease terms and West Virginia law, and they intend to appeal any adverse judgment in the case. Chesapeake and NiSource have filed a joint motion for post-trial review of punitive damages to be heard on March 5, 2007. Chesapeake has established an accrual for amounts it believes will not be indemnified. Should a final nonappealable judgment be entered, Chesapeake believes its share of damages will not have a material adverse effect on its results of operations, financial condition or liquidity.

Chesapeake is subject to other legal proceedings and claims which arise in the ordinary course of business. In our opinion, the final resolution of these proceedings and claims will not have a material effect on the company.

Employment Agreements with Officers. Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and other executive officers, which provide for annual base salaries, various benefits and eligibility for bonus compensation. The agreement with the chief executive officer has a term of five years commencing January

1, 2007. The term of the agreement is automatically extended for one additional year on each December 31 unless the company provides 30 days notice of non-extension. In the event of termination of employment without cause, the chief executive officer's base compensation (defined as base salary plus bonus compensation received during the preceding 12 months) and benefits would continue during the remaining term of the agreement. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation and three times the value of the prior year's benefits, plus a tax gross-up payment, upon the happening of certain events following a change of control, and the company will also provide him office space and secretarial and accounting support for a period of 12 months thereafter. Any stock-based awards held by the chief executive officer and deferred compensation will immediately become 100% vested upon termination of employment without cause, a change of control event, incapacity, death or retirement at or after age 55, and any unexercised stock options will not terminate as the result of termination of employment. The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2009. These agreements provide for the continuation of salary for one year in the event of termination of employment without cause or death and, in the event of a change of control, a payment in the amount of two times the executive officer's base compensation. These executive officers are entitled to continue to receive compensation and benefits for 180 days following termination of employment as a result of incapacity. Any stock-based awards held by such executive officers will immediately become 100% vested upon termination of employment without cause, a change of control, death or retirement at or after age 55.

Environmental Risk. Due to the nature of the oil and natural gas business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a contingent liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at December 31, 2006.

Rig and Other Leases. In a series of transactions in 2006, our wholly owned subsidiary, Nomac Drilling Corporation, sold 24 of its drilling rigs and related equipment for $244 million and entered into a master lease agreement under which it agreed to lease the rigs from the buyer for an initial term of eight years for rental payments of approximately $33 million annually. Nomac's lease obligations are guaranteed by Chesapeake and its other material domestic subsidiaries. These transactions were recorded as sale and operating leasebacks, with an aggregate deferred gain of $28.6 million on the sale which will be amortized to service operations expense over the lease term. Under the rig lease, we have the option to purchase the rigs in 2013 or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal.

Commitments related to these lease payments and other operating leases are not recorded in the accompanying consolidated balance sheets. As of December 31, 2006, minimum future rig lease payments were as follows ($ in thousands):

	Rigs	Other
2007	$ 33,278	$ 6,755
2008	33,394	5,946
2009	33,394	4,279
2010	33,394	1,873
2011	33,394	1,004
After 2011	93,576	1,687
Total	$ 260,430	$ 21,544

Rent expense, including short-term rentals, for the years ended December 31, 2006, 2005 and 2004 was $47.3 million, $29.8 million and $17.9 million, respectively.

Transportation Contracts. Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from one to 93 years. These commitments are not recorded in the accompanying consolidated balance sheets. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter's Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company will receive rights to flow natural gas production through pipelines located in highly competitive markets. Excluded from this summary are demand charges for pipeline projects that are currently seeking regulatory approval. The aggregate amounts of such required demand payments as of December 31, 2006 are as follows ($ in thousands):

2007	$ 21,983
2008	32,582
2009	38,504
2010	36,232
2011	31,869
After 2011	220,461
Total	$ 381,631

In addition, the company is required to pay additional amounts depending on actual quantities shipped under the agreements. The company's total payments under the agreements were $94.9 million in 2006 and $1.4 million in 2005.

Drilling Contracts. We have contracts with various drilling contractors to use 45 drilling rigs in 2007 with terms of one to three years. These commitments are not recorded in the accompanying consolidated balance sheets. Minimum future commitments as of December 31, 2006 are as follows ($ in thousands):

2007	$ 227,796
2008	133,696
2009	33,540
2010	821
After 2010	—
Total	$ 395,853

Chesapeake's service operations companies, as of December 31, 2006, had contracted to acquire 15 rigs to be constructed during 2007. The total remaining cost of the rigs is estimated to be approximately $141.9 million.

Other. As of December 31, 2006, Chesapeake has contracted to acquire compressors during 2007 and 2008 for a total commitment of $149.0 million which is not recorded in the accompanying consolidated balance sheets.

Chesapeake and a leading investment bank have an agreement to lend Mountain Drilling Company, of which Chesapeake is a 49% equity owner, up to $25 million each through December 31, 2009. There was $25 million outstanding under this agreement at December 31, 2006.

5. Income Taxes

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

	Years Ended December 31,		
	2006	2005	2004
		($ in thousands)	
Current	$ 5,000	$ —	$ —
Deferred	1,247,036	545,091	289,771
Total	$ 1,252,036	$ 545,091	$ 289,771

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

	Years Ended December 31,		
	2006	2005	2004
		($ in thousands)	
Computed "expected" federal income tax provision	$ 1,139,376	$ 522,688	$ 281,724
State income taxes and other	112,941	22,608	8,230
Tax percentage depletion	(281)	(205)	(183)
	$ 1,252,036	$ 545,091	$ 289,771

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

	Years Ended December 31, 2006	2005
	($ in thousands)	
Deferred tax liabilities:		
Oil and natural gas properties	$ (3,259,260)	$ (2,227,960)
Other property and equipment	(105,891)	(26,679)
Derivative instruments	(397,811)	—
Investments	—	(42,211)
Deferred tax liabilities	(3,762,962)	(2,296,850)
Deferred tax assets:		
Net operating loss carryforwards	$ 290,471	$ 246,857
Asset retirement obligation	73,793	59,525
Derivative instruments	—	358,660
Investments	7,041	—
Accrued liabilities	4,455	30,648
Percentage depletion carryforwards	5,934	4,603
Alternative minimum tax credits	5,822	5,298
Other	19,503	20,873
Deferred tax assets	407,019	726,464
Total deferred tax asset (liability)	$ (3,355,943)[(a)]	$ (1,570,386)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ —	$ 234,592
Current deferred income tax liability	(38,484)	—
Non-current deferred income tax liability	(3,317,459)	(1,804,978)
	$ (3,355,943)	$ (1,570,386)

(a) In addition to the income tax expense of $1.252 billion, activity during 2006 includes a net liability of $190.4 million related to acquisitions, a liability of $480.7 million related to derivative instruments, a benefit of $49.8 million related to investments, a benefit of $87.6 million related to stock-based compensation and a benefit of $0.1 million related to other miscellaneous items. These items were not recorded as part of the provision for income taxes.

As of December 31, 2006, we classified $38.5 million of deferred tax liabilities as current that were attributable to the current portion of derivative assets and other current temporary differences. As of December 31, 2005, we classified $234.6 million of deferred tax assets as current that were attributable to the current portion of derivative liabilities and other current temporary differences.

At December 31, 2006, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $631.1 million. Additionally, we had $3.6 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $15.9 million of percentage depletion carryforwards. The NOL carryforwards expire from 2011 through 2026. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs. A summary of our NOLs follows:

	NOL	AMT NOL
	($ in thousands)	
Expiration Date:		
December 31, 2011	$ 119,592	$ —
December 31, 2012	51,996	—
December 31, 2018	42,187	—
December 31, 2019	149,627	—
December 31, 2020	5,156	—
December 31, 2021	15,371	—
December 31, 2022	50,410	—
December 31, 2023	66,816	2,740
December 31, 2024	61,171	6
December 31, 2025	30,434	819
December 31, 2026	38,363	—
Total	$ 631,123	$ 3,565

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

Chesapeake.

In the event of an ownership change (as defined for income tax purposes), Section 382 of the Code imposes an annual limitation on the amount of a corporation's taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Certain NOLs acquired through various acquisitions are also subject to limitations.

The following table summarizes our net operating losses as of December 31, 2006 and any related limitations:

	Total	Limited	Annual Limitation
		($ in thousands)	
Net operating loss	$ 631,123	$ 30,570	$ 15,568
AMT net operating loss	$ 3,565	$ 3,565	$ 520

As of December 31, 2006, we do not believe that an ownership change has occurred. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

6. Related Party Transactions

As of December 31, 2006, we had accrued accounts receivable from our CEO, Aubrey K. McClendon, of $11.1 million representing joint interest billings from December 2006 which were invoiced and paid in January 2007. Since Chesapeake was founded in 1989, Mr. McClendon has acquired working interests in virtually all of our oil and natural gas properties by participating in our drilling activities. Joint interest billings to him are settled in cash immediately upon delivery of a monthly joint interest billing.

Under the Founder Well Participation Program, approved by our shareholders in June 2005, Mr. McClendon (and our co-founder and former COO, Tom L. Ward prior to August 10, 2006) may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake's Board of Directors not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the Founder Well Participation Program, which, among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake's working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation. Mr. Ward's participation in the Founder Well Participation Program terminated on August 10, 2006.

As disclosed in Note 8, in 2006, 2005 and 2004 Chesapeake had revenues of $867 million, $851 million and $467 million, respectively, from oil and natural gas sales to Eagle Energy Partners I, L.P., an affiliated entity.

7. Employee Benefit Plans

Our qualified 401(k) profit sharing plan is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except certain employees of Chesapeake Appalachia, L.L.C. On January 1, 2007, a plan we maintained for the employees of our subsidiary Nomac Drilling Corporation was merged into the Chesapeake plan. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) plan accounts, subject to plan limits and those set by the Internal Revenue Service. Chesapeake matches employee contribution dollar for dollar with Chesapeake common stock purchased in the open market for up to a portion of an employee's annual compensation (15% for the Chesapeake plan and 8% in 2006 and 2005 and 6% in 2004 for the Nomac plan). The company contributed $17.5 million, $10.0 million and $6.9 million to the Chesapeake plan in 2006, 2005 and 2004, respectively, and $1.6 million, $0.4 million and $0.2 million to the Nomac plan in 2006, 2005 and 2004, respectively.

In November 2005, Chesapeake acquired Columbia Natural Resources, LLC, which sponsored the Columbia Natural Resources, LLC 401(k) Plan. Chesapeake's 401(k) plan was amended effective January 1, 2006 to honor previous service by employees with CNR and predecessor companies and was open to CNR employees in the Charleston, West Virginia headquarters office as well as exempt, administrative field employees. The CNR plan was adopted by the new employer entity, Chesapeake Appalachia, L.L.C., and was open to all non-administrative field employees, including union employees. The company contributed $0.6 million to this plan in 2006. Effective January 1, 2007, these employees, other than union employees, became eligible to participate in the Chesapeake plan. Union employees will continue participation in the CNR plan pending the outcome of ongoing labor negotiations.

We also maintain a 401(k) make-up plan and a deferred compensation plan, both of which are nonqualified deferred compensation plans. To be eligible to participate in the 401(k) make-up plan, an employee must receive annual compensation (base salary and bonus combined) of at least $100,000 ($95,000 in 2005 and $90,000 in 2004), have a minimum of five years of service as a company employee and have made the maximum contribution allowable under the 401(k) plan. The company matches employee contributions to the 401(k) make-up plan in Chesapeake common stock dollar for dollar for up to 15% of the employee's annual cash compensation. We contributed $2.4 million, $1.6 million and $1.4 million to the 401(k) make-up plan during 2006, 2005 and 2004, respectively.

Employees with at least one year of service receiving an annual base salary of at least $95,000 ($100,000 in 2004) during the 12 months prior to the enrollment date are eligible to participate in our deferred compensation plan. In addition, non-employee directors are able to defer up to 100% of director fees. The maximum compensation that can be deferred by employees under all company deferred compensation plans, including the Chesapeake 401(k) plan, is a total of 75% of base salary and 100% of performance bonus. Chesapeake has made no matching or other contributions to the deferred compensation plan, although the plan permits the company to make discretionary contributions.

Any assets placed in trust by Chesapeake to fund future obligations of the 401(k) make-up plan and the deferred compensation plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the company as to their deferred compensation in the plans.

Chesapeake maintains no post-employment benefit plans except those sponsored by Chesapeake Appalachia, L.L.C. As of December 31, 2006, a total of 188 employees were eligible for these plans. As of January 1, 2007, participation in these plans was limited to union members (135 employees) and continuing eligibility is the subject of ongoing labor negotiations. The Chesapeake Appalachia, L.L.C. benefit plans provide health care and life insurance benefits to eligible employees upon retirement. We account for these benefits on an accrual basis. As of December 31, 2006, the company had accrued $2.8 million in accumulated post-employment benefit liability.

8. Major Customers and Segment Information

Sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) were as follows:

Year Ended December 31,	Customer	Amount ($ in thousands)	Percent of Total Revenues
2006	Eagle Energy Partners I, L.P.	$867,276	16%
2005	Eagle Energy Partners I, L.P.	$851,420	18%
2004	Eagle Energy Partners I, L.P.	$467,387	17%

In September 2003, Chesapeake invested $5.8 million in Eagle Energy Partners I, L.P. and received a 25% limited partnership interest. Through additional investments totaling $27.1 million, Chesapeake has increased its limited partner ownership interest to $32.9 million or approximately 33% as of December 31, 2006. Chesapeake accounts for its investment in Eagle Energy Partners I, L.P. under the equity method of accounting in accordance with APB 18.

In accordance with Statement of Financial Accounting Standards No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have two reportable operating segments. Our exploration and production segment and oil and natural gas marketing segment are managed separately because of the nature of their products and services. The exploration and production segment is responsible for finding and producing natural gas and crude oil. The marketing segment is responsible for gathering, processing, compressing, transporting and selling natural gas and crude oil primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations, which were considered a part of the exploration and production segment prior to 2006. These service operations are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake-operated wells and wells operated by third parties.

Management evaluates the performance of our segments based upon income before income taxes. Revenues from the marketing segment's sale of oil and natural gas related to Chesapeake's ownership interests are reflected as exploration and production revenues. Such amounts totaled $2.558 billion, $2.396 billion and $1.349 billion for 2006, 2005 and 2004, respectively. The following tables present selected financial information for Chesapeake's operating segments. Our drilling and trucking service operations are presented in "Other Operations" for all periods presented.

	Exploration and Production	Marketing	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in thousands)		
For the Year Ended December 31, 2006:					
Revenues	$ 5,618,894	$ 4,134,495	$ 324,777	$ (2,752,571)	$ 7,325,595
Intersegment revenues	—	(2,558,104)	(194,467)	2,752,571	—
Total Revenues	5,618,894	1,576,391	130,310	—	7,325,595
Depreciation, depletion and amortization	1,440,454	9,955	27,997	(15,647)	1,462,759
Interest and other income	21,589	4,114	(240)	—	25,463
Interest expense	300,181	—	541	—	300,722
Other income/expense	117,396	—	—	—	117,396
INCOME BEFORE INCOME TAXES	$ 3,191,563	$ 40,931	$ 106,395	$ (83,530)	$ 3,255,359
TOTAL ASSETS	$ 23,333,306	$ 863,917	$ 786,243	$ (566,299)	$ 24,417,167
CAPITAL EXPENDITURES	$ 8,423,551	$ 254,987	$ 230,940	$ —	$ 8,909,478
For the Year Ended December 31, 2005:					
Revenues	$ 3,272,585	$ 3,788,653	$ 60,755	$ (2,456,703)	$ 4,665,290
Intersegment revenues	—	(2,395,948)	(60,755)	2,456,703	—
Total Revenues	3,272,585	1,392,705	—	—	4,665,290
Depreciation, depletion and amortization	939,904	5,097	5,897	(5,897)	945,001
Interest and other income	9,684	523	299	(54)	10,452
Interest expense	219,800	—	—	—	219,800
Other income/expense	70,419	—	—	—	70,419
INCOME BEFORE INCOME TAXES	$ 1,466,652	$ 26,496	$ 10,089	$ (9,844)	$ 1,493,393
TOTAL ASSETS	$ 15,123,840	$ 688,747	$ 305,875	$ —	$ 16,118,462
CAPITAL EXPENDITURES	$ 7,696,400	$ 132,817	$ 69,945	$ —	$ 7,899,162
For the Year Ended December 31, 2004:					
Revenues	$ 1,936,176	$ 2,122,235	$ 22,864	$ (1,372,007)	$ 2,709,268
Intersegment revenues	—	(1,349,143)	(22,864)	1,372,007	—
Total Revenues	1,936,176	773,092	—	—	2,709,268
Depreciation, depletion and amortization	602,894	8,428	3,775	(3,775)	611,322
Interest and other income	3,944	532	240	(240)	4,476
Interest expense	167,328	—	—	—	167,328
Other income/expense	24,557	—	—	—	24,557
INCOME BEFORE INCOME TAXES	$ 801,583	$ 3,343	$ (1,995)	$ 1,995	$ 804,926
TOTAL ASSETS	$ 7,810,772	$ 318,246	$ 115,491	$ —	$ 8,244,509
CAPITAL EXPENDITURES	$ 3,845,851	$ 42,462	$ 23,957	$ —	$ 3,912,270

9. Stockholders' Equity, Restricted Stock and Stock Options

The following is a summary of the changes in our common shares outstanding for 2006, 2005 and 2004:

	2006	2005	2004
		(in thousands)	
Shares outstanding at January 1	375,511	316,941	221,856
Stock option and warrant exercises	6,969	3,996	2,952
Restricted stock issuances (net of forfeitures)	3,743	3,671	2,686
Preferred stock conversions/exchanges	12,252	18,703	43,447
Common stock issuances for cash	58,750	32,200	46,000
Common stock issued for the purchase of Chaparral Energy, Inc. common stock	1,376	—	—
Shares outstanding at December 31	458,601	375,511	316,941

The following is a summary of the changes in our preferred shares outstanding for 2006, 2005 and 2004:

	6.75%	6.00%	5.00% (2003)	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
				(in thousands)				
Shares outstanding at January 1, 2006	—	99	1,026	89	4,600	3,450	5,750	—
Preferred stock issuances	—	—	—	—	—	—	—	2,300
Conversion/exchange of preferred for common stock	—	(99)	(1,026)	(86)	—	—	—	—
Shares outstanding at December 31, 2006	—	—	—	3	4,600	3,450	5,750	2,300
Shares outstanding at January 1, 2005	—	103	1,725	313	—	—	—	—
Preferred stock issuances	—	—	—	—	4,600	3,450	5,750	—
Conversion/exchange of preferred for common stock	—	(4)	(699)	(224)	—	—	—	—
Shares outstanding at December 31, 2005	—	99	1,026	89	4,600	3,450	5,750	—
Shares outstanding at January 1, 2004	2,998	4,600	1,725	—	—	—	—	—
Preferred stock issuances	—	—	—	313	—	—	—	—
Conversion/exchange of preferred for common stock	(2,998)	(4,497)	—	—	—	—	—	—
Shares outstanding at December 31, 2004	—	103	1,725	313	—	—	—	—

In 2006, shares of our preferred stock were exchanged for or converted into common stock as follows:

- 221,898 shares of 5.0% (Series 2003) cumulative convertible preferred stock were exchanged for or converted into 1,375,670 shares of common stock in privately negotiated exchange transactions or pursuant to conversion rights;
- 804,048 shares of such 5.0% (Series 2003) cumulative convertible preferred stock were exchanged for 4,972,786 shares of common stock pursuant to a tender offer;
- 2,750 shares of 4.125% cumulative convertible preferred stock were exchanged for 172,594 shares of common stock in privately negotiated exchange transactions;
- 83,245 shares of such 4.125% cumulative convertible preferred stock were exchanged for 5,248,126 shares of common stock pursuant to a tender offer; and
- the remaining 99,310 shares of 6.0% cumulative convertible preferred stock were exchanged for or converted into 482,694 shares of common stock in privately negotiated exchange transactions or pursuant to conversion rights.

In 2005, 3,800 shares of 6.00% cumulative convertible preferred stock were converted into 18,468 shares of common stock, 699,054 shares of 5.00% (Series 2003) cumulative convertible preferred stock were exchanged into 4,362,720 shares of common stock and 224,190 shares of 4.125% cumulative convertible preferred stock were exchanged into 14,321,881 shares of common stock.

In 2004, 2,998,000 shares of 6.75% cumulative convertible preferred stock were converted into 19,467,482 shares of common stock, 600,000 shares of 6.0% cumulative convertible preferred stock were exchanged for 3,225,000 shares of common stock in a privately negotiated exchange transaction, and 3,896,890 shares of such 6.0% preferred stock were exchanged for 20,754,817 shares of common stock pursuant to a tender offer.

In connection with the exchanges noted above, we recorded a loss of $10.6 million, $26.9 million and $36.7 million in 2006, 2005 and 2004, respectively. In general, the loss is equal to the excess of the fair value of all common stock exchanged over the fair value of the securities issuable pursuant to the original conversion terms of the preferred stock.

Dividends on our outstanding preferred stock are payable quarterly in cash or, with respect to our 6.25% mandatory convertible preferred stock and our 4.50% cumulative convertible preferred stock, we may pay dividends in cash, common stock or a combination thereof. Following is a summary of our preferred stock, including the primary conversion terms:

Preferred Stock Series	Issue Date	Liquidation Preference per Share	Holder's Conversion Right	Initial Conversion Rate	Conversion Price	Company's Conversion Right From	Company's Market Conversion Trigger
6.25% Mandatory Convertible[(a)]	June/July 2006	$ 250	Any time	7.1715	$ 34.86	Any time	$ 52.29[(b)]
5.00% (Series 2005) Cumulative Convertible	April 2005	$ 100	Any time	3.8811	$ 25.766	April 15, 2010	$ 33.50[(c)]
4.50% Cumulative Convertible	September 2005	$ 100	Any time	2.2639	$ 44.172	September 15, 2010	$ 57.42[(c)]
5.00% (Series 2005B) Cumulative Convertible ..	November 2005	$ 100	Any time	2.5595	$ 39.07	November 15, 2010	$ 50.79[(c)]
4.125% Cumulative Convertible	March/April 2004	$ 1,000	Market price >$21.65	60.0555	$ 16.65	March 15, 2009	$ 21.65[(c)]

(a) Each share converts automatically on June 15, 2009 into 7.1715 to 8.6059 shares of common stock, depending on the common stock market price at the time.
(b) Convertible at initial conversion rate plus cash equal to present value of future dividends to June 15, 2009.
(c) Convertible at the Company's option if the Company's common stock equals or exceeds the trigger price for a specified time period.

Stock-Based Compensation Plans

Under Chesapeake's Long Term Incentive Plan, restricted stock, stock options, stock appreciation rights, performance shares and other stock awards may be awarded to employees, directors and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares of common stock which may be issued under the plan may not exceed 7,000,000 shares. The maximum period for exercise of an option or stock appreciation right may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option or stock appreciation right on the date of grant. Awards granted under the plan become vested at dates or upon the satisfaction of certain performance or other criteria determined by a committee of the board of directors. No awards may be granted under this plan after September 30, 2014. This plan has been approved by our shareholders. Stock options to purchase 150,000 and 50,000 shares of our common stock were issued to our directors from this plan in 2005 and 2004, respectively. In addition, 75,000 and 62,500 shares of restricted stock were issued to our directors from this plan in 2006 and 2005, respectively. There were 2,610 restricted shares issued to employees during 2006 from this plan. As of December 31, 2006, there were 6.7 million shares remaining available for issuance under the plan.

Under Chesapeake's 2003 Stock Incentive Plan, restricted stock and incentive and nonqualified stock options to purchase our common stock may be awarded to employees and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued and sold may not exceed 10,000,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option on the date of grant. Restricted stock and options granted become vested at dates determined by a committee of the board of directors. No awards may be granted under this plan after April 14, 2013. This plan has been approved by our shareholders. There were 4.0 million and 3.9 million restricted shares, net of forfeitures, issued during 2006 and 2005, respectively, from this plan. As of December 31, 2006, there were 59,000 shares remaining available for issuance under the plan.

Under Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, 10,000 shares of Chesapeake's common stock will be awarded to each newly appointed non-employee director on his or her first day of service. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued may not exceed 50,000 shares. This plan was not required to be approved by our shareholders. In each of 2006 and 2005, 10,000 shares of common stock were awarded to new directors from this plan. As of December 31, 2006, there are 20,000 shares remaining available for issuance under this plan. In January 2007, we awarded 10,000 shares of common stock to a new director from this plan.

Under Chesapeake's 2002 Non-Employee Director Stock Option Plan and 1992 Nonstatutory Stock Option Plan, we granted nonqualified options to purchase our common stock to members of our board of directors who are not Chesapeake employees. Subject to any adjustments provided for in the plans, the 2002 plan and the 1992 plan covered a maximum of

500,000 shares and 3,132,000 shares, respectively. The 1992 plan terminated in December 2002 and the 2002 plan terminated in June 2005. Pursuant to a formula award provision in the plans, each non-employee director received a quarterly grant of a ten-year immediately exercisable option to purchase shares of common stock at an exercise price equal to the fair market value of the shares on the date of grant. Both plans were approved by our shareholders.

In addition to the plans described above, we have stock options outstanding to employees under a number of employee stock option plans which are described below. All outstanding options under these plans were at-the-money when granted, with an exercise price equal to the closing price of our common stock on the date of grant and have a ten-year exercise period. These plans were terminated in June 2005 (with the exception of the 1994 plan which expired in October 2004) and therefore no shares remain available for stock option grants under the plans.

Name of Plan	Eligible Participants	Type of Options	Shares Covered	Shareholder Approved
2002 and 2001 Stock Option Plans..	Employees and consultants	Incentive and nonqualified	3,000,000 / 3,200,000	Yes
2002 and 2001 Nonqualified Stock Option Plans..........................	Employees and consultants	Nonqualified	4,000,000 / 3,000,000	No
2000 Employee and 1999 Stock Option Plans.........................	Employees and consultants	Nonqualified	3,000,000 (each plan)	No
1996 and 1994 Stock Option Plans..........................	Employees and consultants	Incentive and nonqualified	6,000,000 /4,886,910	Yes

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is four years from the date of grant for employees and three years for non-employee directors. To the extent amortization of compensation cost relates to employees directly involved in acquisition, exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized in general and administrative expense or production expense. Note 1 details the accounting for our stock-based compensation expense in 2006, 2005 and 2004. As of December 31, 2005, the unamortized balance of unearned compensation recorded as a reduction of stockholders' equity was $89.2 million. Upon adoption of SFAS 123(R) in January 2006, we eliminated the $89.2 million of the unamortized balance of unearned compensation in stockholders' equity and reduced additional paid-in capital by the same amount on our consolidated balance sheet.

A summary of the status of the unvested shares of restricted stock and changes during 2006, 2005 and 2004 is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2006	5,805,210	$ 18.38
Granted	4,392,270	31.77
Vested	(2,818,249)	19.78
Forfeited	(304,470)	25.04
Unvested shares as of December 31, 2006	7,074,761	$ 25.85
Unvested shares as of January 1, 2005	2,684,850	$ 14.35
Granted	3,940,405	20.41
Vested	(739,255)	14.71
Forfeited	(80,790)	17.09
Unvested shares as of December 31, 2005	5,805,210	$ 18.38
Unvested shares as of January 1, 2004	—	$ —
Granted	2,714,900	14.35
Vested	(1,600)	14.16
Forfeited	(28,450)	14.29
Unvested shares as of December 31, 2004	2,684,850	$ 14.35

The aggregate intrinsic value of restricted stock vested during 2006 was approximately $86.1 million.

As of December 31, 2006, there was $155.8 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.73 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the years ended December 31, 2006 and 2005, we recognized excess tax benefits related to restricted stock of $4.3 million and $2.0 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward's Resignation Agreement provided for the immediate vesting of all of his unvested equity awards, which consisted of options to purchase 724,615 shares of Chesapeake's common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock. As a result of this vesting, we incurred an expense of $54.8 million in 2006.

Stock Options

We granted stock options prior to 2006 under several stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable over a four-year period.

The following table provides information related to stock option activity for 2006, 2005 and 2004:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)] ($ in thousands)
Outstanding at January 1, 2006	20,256,013	$ 6.14		
Exercised	(13,494,835)	5.34		$ 352,369
Forfeited/ Canceled	(155,475)	20.22		
Outstanding at December 31, 2006	6,605,703	$ 7.43	5.36	$ 142,829
Exercisable at December 31, 2006	5,337,153	$ 7.02	5.14	$ 117,583
Shares authorized for future grants	6,719,642			
Fair value of options granted during period	$ —			
Outstanding at January 1, 2005	24,228,464	$ 6.00		
Granted	177,500	18.67		
Exercised	(4,032,180)	5.78		
Forfeited/ Canceled	(117,771)	8.51		
Outstanding at December 31, 2005	20,256,013	$ 6.14		
Exercisable at December 31, 2005	15,960,440	$ 5.57		
Shares authorized for future grants	6,452,444			
Fair value of options granted during period	$ 6.21			
Outstanding at January 1, 2004	27,233,285	$ 5.78		
Granted	347,250	14.23		
Exercised	(3,219,877)	4.94		
Forfeited/ Canceled	(132,194)	8.21		
Outstanding at December 31, 2004	24,228,464	$ 6.00		
Exercisable at December 31, 2004	15,441,511	$ 5.06		
Shares authorized for future grants	8,392,285			
Fair value of options granted during period	$ 4.66			

(a) The intrinsic value of a stock option is the amount by which the current market value or the market value upon exercise of the underlying stock exceeds the exercise price of the option.

As of December 31, 2006, there was $1.4 million of total unrecognized compensation cost related to unvested stock options. The cost is expected to be recognized over a weighted average period of 0.28 years.

During the years ended December 31, 2006, 2005 and 2004, we recognized excess tax benefits related to stock options of $83.3 million, $16.5 million and $9.1 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

The following table summarizes information about stock options outstanding at December 31, 2006:

	Outstanding Options			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Number Exercisable	Weighted-Avg. Exercise Price
$ 0.94 — $ 4.00	743,646	2.69	$ 2.51	743,646	$ 2.51
4.06 — 4.06	58	1.45	4.06	58	4.06
5.20 — 5.20	771,827	5.56	5.20	771,827	5.20
5.35 — 5.89	446,890	3.99	5.58	446,890	5.58
6.11 — 6.11	1,175,478	4.75	6.11	1,175,478	6.11
6.13 — 7.74	216,479	4.75	6.91	216,479	6.91
7.80 — 7.80	1,133,174	6.02	7.80	544,262	7.80
7.86 — 10.01	231,901	5.62	8.50	200,609	8.53
10.08 — 10.08	1,337,097	6.48	10.08	789,904	10.08
10.10 — 22.49	549,153	7.20	14.08	448,000	14.50
$ 0.94 — $ 22.49	6,605,703	5.36	$ 7.43	5,337,153	$ 7.02

Shareholder Rights Plan

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

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

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

10. Financial Instruments and Hedging Activities

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2006, our oil and natural gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty.
- Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.
- For call options, Chesapeake receives a cash premium from the counterparty in exchange for the sale of a call option.

If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. Generally, at the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap's designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural gas sales in the month of related production.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap. Changes in the value of cap-swaps and counter-swaps are recorded as adjustments to oil and natural gas sales.

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

Gains or losses from certain derivative transactions are reflected as adjustments to oil and natural gas sales on the consolidated statements of operations. Realized gains (losses) included in oil and natural gas sales were $1.254 billion, ($401.7) million and ($154.9) million in 2006, 2005 and 2004, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and natural gas sales. Unrealized gains (losses) included in oil and natural gas sales were $495.5 million, $41.1 million and $40.9 million, in 2006, 2005 and 2004, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales as unrealized gains (losses). Included in unrealized gains (losses) are gains (losses) on ineffectiveness of $311.1 million, ($76.3) million and ($8.2) million in 2006, 2005 and 2004, respectively.

The estimated fair values of our oil and natural gas derivative instruments as of December 31, 2006 and 2005 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2006	December 31, 2005
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ 1,075	$ (1,081,323)
Natural gas basis protection swaps	186,970	307,308
Fixed-price natural gas cap-swaps	121,866	(161,056)
Fixed-price natural gas counter-swaps	(5,455)	37,785
Natural gas call options[(a)]	(4,873)	(21,461)
Fixed-price natural gas collars	(6,922)	(9,374)
Floating-price natural gas swaps	—	2,607
Fixed-price oil swaps	28,149	(16,936)
Fixed-price oil cap-swaps	24,057	(3,364)
Estimated fair value	$ 344,867	$ (945,814)

(a) After adjusting for $15.4 million and $23.0 million of unrealized premiums, the cumulative unrealized gain related to these call options as of December 31, 2006 and 2005 was $10.5 million and $1.6 million, respectively.

Based upon the market prices at December 31, 2006, we expect to transfer approximately $282.5 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of December 31, 2006 are expected to mature by December 31, 2009.

We have three secured hedging facilities maturing in 2011, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a maximum value. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. The hedging facilities are subject to a 1% per annum exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate oil and natural gas production volumes that we are permitted to hedge under all of our agreements at any one time. The maximum permitted value of transactions under each facility and the fair market values of outstanding transactions are shown below.

	Secured Hedging Facilities		
	#1	#2	#3
		($ in thousands)	
Maximum permitted value of transactions under facility	$ 750,000	$ 500,000	$ 500,000
Fair market value of outstanding transactions, as of December 31, 2006	$ 34,403	$ 59,639	$ —
Fair market value of outstanding transactions, as of February 23, 2007	$ 26,063	$ 16,027	$ 29,243

We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element, and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs. The aggregate fair value of the remaining CNR derivatives as of December 31, 2006 was a liability of $254.4 million.

In 2006, Chesapeake lifted a portion of its 2007, 2008 and 2009 hedges and as a result received $744.1 million in cash from its hedging counterparties. The gain has been recorded in accumulated other comprehensive income and in oil and natural gas sales based on the designation of the hedges. For amounts initially recorded in other comprehensive income, the gain will be recognized in oil and natural gas sales in the month of the hedged production.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. Realized gains (losses) included in interest expense were ($1.9) million, $4.9 million and $0.8 million in 2006, 2005 and 2004, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were $1.6 million, $1.6 million and ($5.3) million in 2006, 2005 and 2004, respectively.

As of December 31, 2006, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value ($ in thousands)
September 2004 – August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,695)
July 2005 – January 2015	$150,000,000	7.750%	6 month LIBOR plus 289 basis points	(5,866)
July 2005 – June 2014	$150,000,000	7.500%	6 month LIBOR plus 282 basis points	(6,133)
September 2005 – August 2014	$250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(6,807)
October 2005 – June 2015	$200,000,000	6.375%	6 month LIBOR plus 112 basis points	(2,860)
October 2005 – January 2018	$250,000,000	6.250%	6 month LIBOR plus 99 basis points	(6,334)
December 2006 – July 2013	$250,000,000	7.625%	6 month LIBOR plus 266.5 basis points	((2,755)
				$ (33,450)

Subsequent to December 31, 2006, we entered into the following interest rate swaps (which qualify as fair value hedges) to convert a portion of our long-term fixed-rate debt to floating-rate debt:

Term	Notional Amount	Fixed Rate	Floating Rate
January 2007 – July 2013	$250,000,000	7.625%	6 month LIBOR plus 251 basis points
January 2007 – August 2017	$250,000,000	6.500%	6 month LIBOR plus 124.5 basis points

Additionally, subsequent to December 31, 2006, we sold call options to a counterparty with respect to these two interest rate swaps and received $3.7 million in premiums. If exercised, the call option on the 7.625% interest rate swap gives the counterparty the right to terminate the interest rate swap on July 12, 2007 for a payment to Chesapeake of $2.0 million. The call option on the 6.50% interest rate swap gives the counterparty the right to terminate the interest rate swap on August 15, 2007 for a payment of $2.0 million to Chesapeake.

In 2006, we closed six interest rate swaps for gains totaling $5.7 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes. Subsequent to December 31, 2006, we closed one interest rate swap for a gain of $1.0 million.

Foreign Currency Derivatives

On December 5, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties will pay Chesapeake €18.75 million and Chesapeake will pay the counterparties $29.95 million, which will yield an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €600 million and Chesapeake will pay the counterparties $799.5 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($791.8 million at December 31, 2006) using an exchange rate of $1.3197 to €1.00. The cross currency swap is recorded on the consolidated balance sheet at a fair value of ($18.9) million at December 31, 2006. The translation adjustment to notes payable is completely offset by the fair value of the cross currency swap and therefore there is no impact to the consolidated statement of operations. The remaining value of the cross currency swap related to future interest payments is reported in other comprehensive income.

Fair Value of Financial Instruments

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

The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term fixed-rate debt and our convertible preferred stock using primarily quoted market prices. Our carrying amounts for such debt, excluding discounts or premiums related to interest rate derivatives, at December 31, 2006 and 2005 were $7.215 billion and $5.429 billion, respectively, compared to approximate fair values of $7.336 billion and $5.582 billion, respectively. The carrying amounts for our convertible preferred stock as of December 31, 2006 and 2005 were $1.958 billion and $1.577 billion, respectively, compared to approximate fair values of $1.949 billion and $1.686 billion, respectively.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in equity instruments and accounts receivable. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

11. Supplemental Disclosures About Oil And Natural Gas Producing Activities

Net Capitalized Costs

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

	December 31,	
	2006	2005
	($ in thousands)	
Oil and natural gas properties:		
Proved	$ 21,949,295	$ 15,880,919
Unproved	3,796,405	1,739,095
Total	25,745,700	17,620,014
Less accumulated depreciation, depletion and amortization	(5,291,846)	(3,945,703)
Net capitalized costs	$ 20,453,854	$ 13,674,311

Unproved properties not subject to amortization at December 31, 2006 and 2005 consisted mainly of leasehold acquired through corporate and significant oil and natural gas property acquisitions and through direct purchases of leasehold. We capitalized approximately $179.1 million, $79.0 million and $36.2 million of interest during 2006, 2005 and 2004, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. We will continue to evaluate our unevaluated properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

Our ceiling test calculation as of December 31, 2006 indicated an impairment of our oil and natural gas properties of approximately $500 million, net of income tax. However, natural gas prices subsequent to December 31, 2006 have improved sufficiently to eliminate this calculated impairment. As a result, we were not required to record a write-down of our oil and natural gas properties under the full-cost method of accounting in the fourth quarter of 2006. Based on spot prices for oil and natural gas as of December 31, 2006, cash flow hedges increased the full-cost ceiling by $1.6 billion.

Costs Incurred in Oil and Natural Gas Acquisition, Exploration and Development

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

	Years Ended December 31,		
	2006	2005	2004
		($ in thousands)	
Acquisition of properties:			
Proved properties	$ 1,175,616	$ 3,554,651	$ 1,541,920
Unproved properties	2,855,848	1,375,675	570,495
Deferred income taxes	179,731	251,722	463,949
Total	4,211,195	5,182,048	2,576,364
Development costs:			
Development drilling[(a)]	2,772,149	1,566,730	863,268
Leasehold acquisition costs	616,550	290,946	110,530
Asset retirement obligation and other	23,214	52,619	41,924
Total	3,411,913	1,910,295	1,015,722
Exploration costs:			
Exploratory drilling	348,703	253,341	128,635
Geological and geophysical costs[(b)]	153,993	70,901	55,618
Total	502,696	324,242	184,253
Sales of oil and natural gas properties	(118)	(9,769)	(12,048)
Total	$ 8,125,686	$ 7,406,816	$ 3,764,291

(a) Includes capitalized internal cost of $147.3 million, $94.1 million and $45.4 million, respectively.
(b) Includes capitalized internal cost of $13.3 million, $8.1 million and $6.3 million, respectively.

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

Chesapeake's results of operations from oil and natural gas producing activities are presented below for 2006, 2005 and 2004. The following table includes revenues and expenses associated directly with our oil and natural gas producing activities. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil and natural gas operations.

	Years Ended December 31,		
	2006	2005	2004
		($ in thousands)	
Oil and natural gas sales[(a)]	$ 5,618,894	$ 3,272,585	$ 1,936,176
Production expenses	(489,499)	(316,956)	(204,821)
Production taxes	(176,440)	(207,898)	(103,931)
Depletion and depreciation	(1,358,519)	(894,035)	(582,137)
Imputed income tax provision[(b)]	(1,383,858)	(676,599)	(376,303)
Results of operations from oil and natural gas producing activities	$ 2,210,578	$ 1,177,097	$ 668,984

(a) Includes $495.5 million, $41.1 million and $40.9 million of unrealized gains on oil and natural gas derivatives for the years ended December 31, 2006, 2005 and 2004, respectively.
(b) The imputed income tax provision is hypothetical (at the effective income tax rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision will be payable.

Oil and Natural Gas Reserve Quantities (unaudited)

Independent petroleum engineers and Chesapeake's petroleum engineers have evaluated our proved reserves. The portion of the proved reserves (by volume) evaluated by each for 2006, 2005 and 2004 is presented below.

	Years ended December 31,		
	2006	2005	2004
Netherland, Sewell & Associates, Inc.	32%	25%	23%
Data and Consulting Services, Division of Schlumberger Technology Corporation	16	16	—
Lee Keeling and Associates, Inc.	14	15	22
Ryder Scott Company L.P.	10	12	13
LaRoche Petroleum Consultants, Ltd.	8	8	10
H.J. Gruy and Associates, Inc.	—	2	6
Miller and Lents, Ltd.	—	—	1
Internal petroleum engineers	20	22	25
	100%	100%	100%

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

Proved oil and natural gas reserves represent the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by natural gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved developed oil and natural gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production responses that increased recovery will be achieved.

Presented below is a summary of changes in estimated reserves of Chesapeake for 2006, 2005 and 2004:

	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
December 31, 2006			
Proved reserves, beginning of period	103,323	6,900,754	7,520,690
Extensions, discoveries and other additions	8,456	777,858	828,594
Revisions of previous estimates	(3,822)	539,606	516,676
Production	(8,654)	(526,459)	(578,383)
Sale of reserves-in-place	(3)	(123)	(141)
Purchase of reserves-in-place	6,730	627,798	668,178
Proved reserves, end of period	106,030	8,319,434	8,955,614
Proved developed reserves:			
Beginning of period	76,238	4,442,270	4,899,694
End of period	76,705	5,113,211	5,573,441
December 31, 2005			
Proved reserves, beginning of period	87,960	4,373,989	4,901,751
Extensions, discoveries and other additions	12,460	930,800	1,005,563
Revisions of previous estimates	(2,123)	53,950	41,204
Production	(7,698)	(422,389)	(468,577)
Sale of reserves-in-place	(26)	(332)	(486)
Purchase of reserves-in-place	12,750	1,964,736	2,041,235
Proved reserves, end of period	103,323	6,900,754	7,520,690
Proved developed reserves:			
Beginning of period	62,713	2,842,141	3,218,418
End of period	76,238	4,442,270	4,899,694
December 31, 2004			
Proved reserves, beginning of period	51,422	2,860,040	3,168,575
Extensions, discoveries and other additions	7,601	771,125	816,728
Revisions of previous estimates	6,109	108,863	145,518
Production	(6,764)	(322,009)	(362,593)
Sale of reserves-in-place	(102)	(3,329)	(3,940)
Purchase of reserves-in-place	29,694	959,299	1,137,463
Proved reserves, end of period	87,960	4,373,989	4,901,751
Proved developed reserves:			
Beginning of period	38,442	2,121,734	2,352,389
End of period	62,713	2,842,141	3,218,418

During 2006, Chesapeake acquired approximately 668 bcfe of proved reserves through purchases of oil and natural gas properties for consideration of $1.176 billion (primarily in 15 separate transactions of greater than $10 million each). We also sold 0.1 bcfe of proved reserves for consideration of approximately $0.1 million. During 2006, we recorded upward revisions of 517 bcfe to the December 31, 2005 estimates of our reserves. Included in the revisions were 212 bcfe of downward adjustments caused by lower natural gas prices at December 31, 2006, offset by 729 bcfe of positive performance related revisions. Lower prices reduce the economic lives of the underlying oil and natural gas properties and thereby decrease the estimated future reserves. The weighted average oil and natural gas wellhead prices used in computing our reserves were $56.25 per bbl and $5.41 per mcf at December 31, 2006.

During 2005, Chesapeake acquired approximately 2.041 tcfe of proved reserves through purchases of oil and natural gas properties for consideration of $3.806 billion (primarily in 18 separate transactions of greater than $10 million each). We also sold 0.5 bcfe of proved reserves for consideration of approximately $9.8 million. During 2005, we recorded upward revisions of 41 bcfe to the December 31, 2004 estimates of our reserves. Approximately 24 bcfe of the upward revisions was caused by higher oil and natural gas prices at December 31, 2005. Higher prices extend the economic lives of the underlying oil and natural gas properties and thereby increase the estimated future reserves. The weighted average oil and natural gas wellhead prices used in computing our reserves were $56.41 per bbl and $8.76 per mcf at December 31, 2005.

During 2004, Chesapeake acquired approximately 1.137 tcfe of proved reserves through purchases of oil and natural gas properties for consideration of $2.006 billion (primarily in 15 separate transactions of greater than $10 million each). We also sold 4 bcfe of proved reserves for consideration of approximately $12.0 million. During 2004, we recorded upward revisions of 146 bcfe to the December 31, 2003 estimates of our reserves. Approximately 5 bcfe of the upward revisions was caused by higher oil and natural gas prices at December 31, 2004. Higher prices extend the economic lives of the underlying oil and natural gas properties and thereby increase the estimated future reserves. The weighted average oil and natural gas wellhead prices used in computing our reserves were $39.91 per bbl and $5.65 per mcf at December 31, 2004.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

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

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

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

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

	Years Ended December 31,		
	2006	2005	2004
		($ in thousands)	
Future cash inflows	$ 50,984,435[a]	$ 66,286,940[b]	$ 28,245,336[c]
Future production costs	(13,790,630)	(14,794,530)	(6,542,219)
Future development costs	(6,803,715)	(4,676,287)	(2,115,511)
Future income tax provisions	(8,876,731)	(14,856,446)	(5,663,575)
Future net cash flows	21,513,359	31,959,677	13,924,031
Less effect of a 10% discount factor	(11,506,788)	(15,991,766)	(6,278,492)
Standardized measure of discounted future net cash flows	$ 10,006,571	$ 15,967,911	$ 7,645,539

(a) Calculated using weighted average prices of $56.25 per barrel of oil and $5.41 per mcf of natural gas.
(b) Calculated using weighted average prices of $56.41 per barrel of oil and $8.76 per mcf of natural gas
(c) Calculated using weighted average prices of $39.91 per barrel of oil and $5.65 per mcf of natural gas.

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

	Years Ended December 31,		
	2006	2005	2004
		($ in thousands)	
Standardized measure, beginning of period[a]	$ 15,967,911	$ 7,645,539	$ 5,326,753
Sales of oil and natural gas produced, net of production costs[b]	(3,203,804)	(3,108,277)	(1,741,438)
Net changes in prices and production costs	(10,953,623)	3,249,132	(730,020)
Extensions and discoveries, net of production and development costs	1,183,910	3,144,966	1,784,166
Changes in future development costs	(743,002)	(151,133)	33,284
Development costs incurred during the period that reduced future development costs	953,933	490,902	226,415
Revisions of previous quantity estimates	947,719	122,924	317,518
Purchase of reserves-in-place	1,134,615	6,252,030	2,580,973
Sales of reserves-in-place	(25)	(939)	(5,604)
Accretion of discount	2,293,359	1,050,439	733,314
Net change in income taxes	3,325,144	(4,106,833)	(852,462)
Changes in production rates and other	(899,566)	1,379,161	(27,360)
Standardized measure, end of period[a]	$ 10,006,571	$ 15,967,911	$ 7,645,539

(a) The discounted amounts related to cash flow hedges that would affect future net cash flows have not been included in any of the periods presented.
(b) Excluding gains (losses) on derivatives.

12. Asset Retirement Obligations

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

	Years Ended December 31,	
	2006	2005
	($ in thousands)	
Asset retirement obligations, beginning of period	$ 156,593	$ 73,718
Additions	21,958	51,168
Revisions[a]	3,021	26,731
Settlements and disposals	(1,006)	(1,087)
Accretion expense	12,206	6,063
Asset retirement obligations, end of period	$ 192,772	$ 156,593

(a) Based on increasing service costs, we revised our asset retirement obligation related to oil and natural gas wells in 2006 and 2005.

13. Acquisitions and Investments

Oil and Natural Gas Properties

Through multiple purchases completed in 2006, we invested $1.355 billion in proved properties, including approximately $179.7 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions. Additionally we invested $2.856 billion in unproved property acquisitions.

On November 14, 2005, Chesapeake completed its acquisition of Columbia Natural Resources, LLC ("CNR"), an Appalachian Basin natural gas producer with properties principally located in West Virginia, Kentucky, Ohio, Pennsylvania and New York. The cash purchase price totaled $2.2 billion and was allocated based on the fair values of the assets and liabilities acquired at the date of acquisition. The acquisition was accounted for using the purchase method of accounting and has been included in the consolidated financial statements of Chesapeake since the date of acquisition.

The purchase price paid for CNR was allocated as follows ($ in thousands):

Current assets	$ 73,637
Evaluated oil and natural gas properties	2,368,726
Unevaluated properties	500,000
Other assets	178,431
Current liabilities	(185,003)
Derivative liability	(591,756)
Asset retirement obligation	(39,528)
Deferred taxes	(3,293)
Credit facility payoff	(96,116)
Other long-term deferred liabilities	(5,098)
Net cash consideration	$ 2,200,000

The pro forma information below is presented for illustrative purposes only and is based on estimates and assumptions deemed appropriate by Chesapeake. The pro forma information should not be relied upon as an indication of the operating results that Chesapeake would have achieved if the acquisition had occurred at the beginning of each period presented, or of Chesapeake's results after the CNR acquisition. The pro forma information for the years ended December 31, 2005 and 2004 reflect the CNR acquisition as if the acquisition occurred on January 1, 2004.

	Years Ended December 31,	
	2005	2004
	($ in millions, except per share amounts)	
Revenues	$ 4,847.4	$ 2,913.6
Income from continuing operations	$ 1,758.5	$ 979.0
Net income available to common shareholders	$ 829.9	$ 390.3
Income per Common Share:		
Basic	$ 2.41	$ 1.41
Diluted	$ 2.23	$ 1.28

Drilling Rigs and Oilfield Trucks

In January 2006, we acquired a privately-owned Oklahoma-based oilfield trucking service company for $47.5 million. In addition to the cash purchase price, we recorded approximately $10.7 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired in connection with this acquisition. Of the total $58.2 million purchase price, $27.3 million was allocated to tangible equipment, $11.0 million to intangibles and $19.9 million to goodwill. The amounts allocated to intangibles and goodwill are included in long-term assets in the accompanying consolidated balance sheet. Goodwill is not amortized but is subject to an annual assessment of impairment. In February 2006, we acquired 13 drilling rigs and related assets through our wholly owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-owned drilling contractor with operations in East Texas and North Louisiana, for $150 million. In July 2006, we acquired 15 rigs and related trucking assets from a drilling contractor in the Appalachian Basin for approximately $70 million in cash.

Acquisitions were recorded using the purchase method of accounting and, accordingly, results of operations of these acquired activities and assets have been included in Chesapeake's results of operations from the respective closing dates of the acquisitions.

Investments

In August 2006, we invested $254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services, with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for $240 million in cash and 1,375,989 newly issued shares of our common stock valued at $40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma. In 2006, we sold our investment in publicly-traded Pioneer Drilling Company ("Pioneer") common stock, realizing proceeds of $158.9 million and a gain of $117.4 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

14. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2006 and 2005 are as follows ($ in thousands except per share data):

	Quarters Ended			
	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006
Total revenues	$ 1,944,567	$ 1,584,016	$ 1,924,411	$ 1,867,601
Gross profit[a]	951,632	673,164	953,389	835,037
Net income	623,723[b]	359,903	548,335	471,362
Net earnings per common share:				
Basic	$ 1.64	$ 0.87	$ 1.25	$ 1.05
Diluted	$ 1.44	$ 0.82	$ 1.13	$ 0.96

	Quarters Ended			
	March 31, 2005	June 30, 2005	September 30, 2005	December 31, 2005
Total revenues	$ 783,450	$ 1,048,018	$ 1,082,843	$ 1,750,979
Gross profit[a]	237,537	425,463	335,634	774,526
Net income	125,010[c]	193,779[d]	176,988[e]	452,525[f]
Net earnings per common share:				
Basic	$ 0.39	$ 0.58	$ 0.46	$ 1.25
Diluted	$ 0.36	$ 0.52	$ 0.43	$ 1.11

(a) Total revenue less operating costs.
(b) Includes a pre-tax employee retirement expense of $54.8 million and a pre-tax gain on sale of investment of $117.4 million.
(c) Includes a pre-tax loss on repurchases and exchanges of debt of $0.9 million.
(d) Includes a pre-tax loss on repurchases and exchanges of debt of $68.4 million.
(e) Includes a pre-tax loss on repurchases and exchanges of debt of $0.7 million.
(f) Includes a pre-tax loss on repurchases and exchanges of debt of $0.4 million.

15. Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In December 2004, the FASB issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, *Accounting for Stock-Based Compensation*. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We adopted this statement effective January 1, 2006. The effect of SFAS 123(R) is more fully described in Note 1.

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. EITF Issue No. 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We adopted this issue effective April 1, 2006. The adoption of EITF Issue No. 04-13 did not have a material impact on our financial statements.

In June 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. Based on our evaluation as of December 31, 2006, we do not expect that FIN 48 will have a material impact on our financial position, results of operations or cash flows.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments – an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. We are currently evaluating the provisions of SFAS 155 and believe that adoption will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently assessing the impact, if any, SFAS 157 and believe that adoption will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. This statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement is effective as of the end of the fiscal year ending after December 15, 2006. SFAS 158 did not have a material impact on our financial position, results of operations or cash flows.

Schedule II

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

Description	Balance at Beginning of Period	Additions: Charged To Expense	Additions: Charged To Other Accounts	Deductions	Balance at End of Period
December 31, 2006:					
Allowance for doubtful accounts	$ 4,904	$ 626	$ 18	$ —	$ 5,548
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —
December 31, 2005:					
Allowance for doubtful accounts	$ 4,648	$ 114	$ 142	$ —	$ 4,904
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —
December 31, 2004:					
Allowance for doubtful accounts	$ 2,669	$ 975	$ 1,004	$ —	$ 4,648
Valuation allowance for deferred tax assets	$ 6,805	$ —	$ —	$ 6,805[a]	$ —

(a) As of December 31, 2004, we determined that it is more likely than not that the $6.8 million of the net deferred tax assets related to net operating losses generated by Louisiana properties would be realized due to acquisitions which occurred in 2004. Therefore, the $6.8 million valuation allowance was reversed.

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

Not applicable.

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

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of December 31, 2006, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake's Chief Executive Officer and Chief Financial Officer of the effectiveness of the design and operation of Chesapeake's disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of December 31, 2006, to ensure that information required to be disclosed by Chesapeake is accumulated and communicated to Chesapeake management, including Chesapeake's Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls

No changes in the company's internal control over financial reporting occurred during the quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management's report on internal control over financial reporting and the attestation report of our independent registered public accounting firm are included in Item 8 of this report.

ITEM 9B. ***Other Information***

Not applicable.

PART III

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

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2007.

ITEM 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2007.

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

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2007.

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

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2007.

ITEM 14. ***Principal Accountant Fees and Services***

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2007.

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules*

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

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

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

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

Exhibit Number	Description
3.1.1	Chesapeake's Restated Certificate of Incorporation, as amended. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.2	Certificate of Designation for Series A Junior Participating Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.3	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.4 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B). Incorporated herein by reference to Exhibit 3.1 to Chesapeake's current report on Form 8-K filed November 9, 2005.
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended. Incorporated herein by reference to Exhibit 3.1.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2005.
3.1.6	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake's current report on Form 8-K filed September 15, 2005.
3.1.7	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake's current report on Form 8-K dated June 30, 2006.
3.2	Chesapeake's Amended and Restated Bylaws. Incorporated herein by reference to Exhibit 3.2 of Chesapeake's annual report on Form 10-K for the year ended December 31, 2003.
4.1	Indenture dated as of May 27, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Trust Company, N.A., as Trustee, with respect to 7.5% senior notes due 2014. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's registration statement on Form S-4 (No. 333-116555). First Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Second Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.11.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Third Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Fourth Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Fifth Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Sixth Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Seventh Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Eighth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.1.1*	Ninth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2014.
4.2	Indenture dated as of August 2, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as

Subsidiary Guarantors, and the Bank of New York Trust Company, N.A., as Trustee, with respect to 7.0% senior notes due 2014. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's registration statement on Form S-4 (No. 333-118378). First Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.12.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Second Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.12.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Third Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Fourth Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Fifth Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Sixth Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.2.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Seventh Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Eighth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.

4.2.1* Ninth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.

4.3 Indenture dated as of December 20, 2002 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to our 7.75% Senior Notes due 2015. Incorporated herein by reference to Exhibit 4.5 to Chesapeake's registration statement on Form S-4 (No. 333-102445) First Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's report on Form 10-K/A for the year ended December 31, 2002. Second Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Third Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003. Fourth Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2003. Fifth Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Sixth Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.6.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Seventh Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Eighth Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Ninth Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Tenth Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Eleventh Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Twelfth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.

4.3.1* Thirteenth Supplemental Indenture dated February 9, 2007 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 7.75% Senior Notes due 2015.

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

4.5 Sixth Amended and Restated Credit Agreement, dated as of February 3, 2006, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, BNP Paribas, as Syndication Agent, Bank of America, N.A., Calyon New York Branch and SunTrust Bank, as Co-Documentation Agents, and the several lenders from time to time parties thereto. Incorporated herein by reference to Exhibit 4.8 to Chesapeake's current report on Form 8-K dated February 8, 2006.

4.6 Indenture dated as of March 5, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as

Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 7.5% Senior Notes due 2013. First Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Second Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003. Third Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2003. Fourth Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Fifth Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.9.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Sixth Supplemental Indenture dated January 31, 2005. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Seventh Supplemental Indenture dated July 15, 2005. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Eighth Supplemental Indenture dated November 14, 2005. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Ninth Supplemental Indenture dated February 24, 2006. Incorporated herein by reference to Exhibit 4.6.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Tenth Supplemental Indenture dated May 8, 2006. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Eleventh Supplemental Indenture dated October 18, 2006. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.

4.6.1* Twelfth Supplemental Indenture dated February 9, 2007 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 7.5% Senior Notes due 2013.

4.7 Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2016. Incorporated herein by reference to Exhibit 4.2 to Chesapeake's registration statement on Form S-4/A (No. 333-110668). First Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2003. Second Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Third Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.10.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Fourth Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Fifth Supplemental Indenture dated July 15, 2005. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Sixth Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Seventh Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.7.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Eighth Supplemental Indenture dated May 8, 2006. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Ninth Supplemental Indenture dated October 18, 2006. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.

4.7.1* Tenth Supplemental Indenture dated February 9, 2007 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2016.

4.8 Indenture dated as of December 8, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A. Trust Company, N.A., as Trustee, with respect to 6.375% senior notes due 2015. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's current report on Form 8-K dated December 14, 2004. First Supplemental Indenture dated January 31, 2005. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Second Supplemental Indenture dated May 13, 2005. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Third Supplemental Indenture dated July 15, 2005. Incorporated by reference herein to Exhibit 4.11.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Fourth Supplemental Indenture dated November 14, 2005. Incorporated herein by reference to Exhibit 4.8.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Fifth Supplemental Indenture dated February 24, 2006. Incorporated herein by reference to Exhibit 4.8.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Sixth Supplemental Indenture dated May 8, 2006. Incorporated by reference herein to Exhibit 4.8.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Seventh Supplemental Indenture dated October 18, 2006. Incorporated by reference herein to Exhibit 4.8.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.

4.8.1*	Eighth Supplemental Indenture dated February 9, 2007 to Indenture dated as of December 8, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.375% senior notes due 2015.
4.9	Indenture dated as of April 19, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.625% senior notes due 2016. Incorporated herein by reference to Exhibit 4.12 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2005. First Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.12.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Second Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Third Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.9.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Fourth Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Fifth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.9.1*	Sixth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of April 19, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.625% senior notes due 2016.
4.10	Indenture dated as of June 20, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.25% senior notes due 2018. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. First Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Second Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.10.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Third Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Fourth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.10.1*	Fifth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of June 20, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.25% senior notes due 2018.
4.11	Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.50% senior notes due 2017. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's current report on Form 8-K dated August 16, 2005. First Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Second Supplemental Indenture dated as of February 1, 2006. Incorporated herein by reference to Exhibit 4.11.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Third Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.11.3 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Fourth Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Fifth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.11.1*	Sixth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.50% senior notes due 2017.
4.12	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2020. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's current report on Form 8-K dated November 8, 2005. First Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.3 to Chesapeake's registration statement on Form S-4 (No. 333-132263). Second Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to

	Exhibit 4.4 to Chesapeake's registration statement on Form S-4 (No. 333-132263). Third Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.12.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Fourth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.12.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.12.1*	Fifth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2020.
4.13	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 2.75% contingent convertible senior notes due 2035. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's current report on Form 8-K dated November 8, 2005. First Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.5 to Chesapeake's registration statement on Form S-3 (No. 333-132261). Second Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's registration statement on Form S-3 (No. 333-132261). Third Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.13.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Fourth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.13.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.13.1*	Fifth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 2.75% contingent convertible senior notes due 2035.
4.14	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 7.625% senior notes due 2013. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's current report on Form 8-K dated June 30, 2006. First Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.14.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.14.1*	Second Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of June 30, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 7.625% senior notes due 2013.
4.15	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% senior notes due 2017. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's current report on Form 8-K dated December 6, 2006.
4.15.1*	First Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% senior notes due 2017.
10.1.1†	Chesapeake's 2003 Stock Incentive Plan, as amended. Incorporated herein by reference to Exhibit 10.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
10.1.1.1†	Form of Restricted Stock Award Agreement for Chesapeake's 2003 Stock Incentive Plan. Incorporated herein by reference to Exhibit 10.1.14.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.2†	Chesapeake's 1992 Nonstatutory Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.3†	Chesapeake's 1994 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
10.1.4†	Chesapeake's 1996 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.4 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
10.1.4.1†	Form of Incentive Stock Option Agreement for Chesapeake's 1996 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.

10.1.4.2†	Form of Nonqualified Stock Option Agreement for Chesapeake's 1996 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.4.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.5†	Chesapeake's 1999 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.5 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
10.1.5.1†	Form of Nonqualified Stock Option Agreement for Chesapeake's 1999 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.5.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.6†	Chesapeake's 2000 Employee Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
10.1.6.1†	Form of Nonqualified Stock Option Agreement for Chesapeake's 2000 Employee Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.8†	Chesapeake's 2001 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.8 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
10.1.8.1†	Form of Incentive Stock Option Agreement for Chesapeake's 2001 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.8.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.8.2†	Form of Nonqualified Stock Option Agreement for Chesapeake's 2001 Stock Option Plan and 2001 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.8.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.10†	Chesapeake's 2001 Nonqualified Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.10 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
10.1.11†	Chesapeake's 2002 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.11 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
10.1.11.1†	Form of Incentive Stock Option Agreement for Chesapeake's 2002 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.11.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.11.2	Form of Nonqualified Stock Option Agreement for Chesapeake's 2002 Stock Option Plan and 2002 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.11.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.12†	Chesapeake's 2002 Non-Employee Director Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 2002 annual meeting of shareholders filed April 29, 2002.
10.1.12.1†	Form of Stock Option Agreement for Chesapeake's 2002 Non-Employee Director Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.12.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.13†	Chesapeake's 2002 Nonqualified Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.13 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
10.1.14†	Chesapeake's 2003 Stock Award Plan for Non-Employee Directors. Incorporated herein by reference to Exhibit 10.1.14 to Chesapeake's annual report of Form 10-K/A for the year ended December 31, 2002.
10.1.15†	Chesapeake Energy Corporation 401(k) Make-Up Plan. Incorporated herein by reference to Exhibit 10.1.15 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002.
10.1.15.1†	Chesapeake Energy Corporation 401(k) Make-Up Plan – 2005. Incorporated herein by reference to Exhibit 10.1.15.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004.
10.1.16†	Chesapeake Energy Corporation Deferred Compensation Plan. Incorporated herein by reference to Exhibit 10.1.16 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002.
10.1.16.1†	Chesapeake Energy Corporation Deferred Compensation Plan – 2005. Incorporated herein by reference to Exhibit 10.1.16.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004.
10.1.17†	Form of Stock Option Grant Notice. Incorporated herein by reference to Exhibit 10.1.15 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.18†*	Chesapeake's Long Term Incentive Plan, as amended.

10.1.18.1† Form of Non-Employee Director Stock Option Agreement for the Long Term Incentive Plan. Incorporated herein by reference to Exhibit 10.1.18.1 to Chesapeake's current report on Form 8-K dated June 16, 2005.

10.1.18.2† Form of Restricted Stock Award Agreement for the Long Term Incentive Plan. Incorporated herein by reference to Exhibit 10.1.18.2 to Chesapeake's current report on form 8-K dated June 16, 2005.

10.1.18.3† Form of Non-Employee Director Restricted Stock Award Agreement for the Long Term Incentive Plan. Incorporated herein by reference to Exhibit 10.1.18.3 to Chesapeake's current report on Form 8-K dated June 16, 2005.

10.1.19† Founder Well Participation Program. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 2005 annual meeting of shareholders filed April 29, 2005.

10.2.1† Sixth Amended and Restated Employment Agreement dated as of January 1, 2007, between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.1 to Chesapeake's current report on Form 8-K dated December 20, 2006.

10.2.2† Employment Agreement dated as of October 1, 2006 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Chesapeake's current report on Form 8-K filed October 5, 2006.

10.2.3† Employment Agreement dated as of October 1, 2006 between Steven C. Dixon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Chesapeake's current report on Form 8-K filed October 5, 2006.

10.2.4† Employment Agreement dated as of October 1, 2006 between J. Mark Lester and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.4 to Chesapeake's current report on Form 8-K filed October 5, 2006.

10.2.5†* Employment Agreement dated as of January 1, 2007 between Douglas J. Jacobson and Chesapeake Energy Corporation.

10.2.6† Employment Agreement dated as of January 1, 2007 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Chesapeake's current report on Form 8-K filed December 20, 2006.

10.2.7† Employment Agreement dated as of October 1, 2006 between Henry J. Hood and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.7 to Chesapeake's current report on Form 8-K filed October 5, 2006.

10.2.8† Employment Agreement dated as of October 1, 2006 between Michael A. Johnson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Chesapeake's current report on Form 8-K filed October 5, 2006.

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

10.4† Non-Employee Director Compensation. Incorporated herein by reference to Exhibit 10.4 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006.

10.5†* Named Executive Officer Compensation.

10.6 Rights Agreement dated July 15, 1998 between Chesapeake and UMB Bank, N.A., as Rights Agent. Incorporated herein by reference to Exhibit 1 to Chesapeake's registration statement on Form 8-A filed July 16, 1998. Amendment No. 1 dated September 11, 1998. Incorporated herein by reference to Exhibit 10.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 1998. Amendment No. 2 dated March 3, 2006. Incorporated herein by reference to Exhibit 10.6.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005.

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

21* Subsidiaries of Chesapeake

23.1* Consent of Pricewaterhouse Coopers, LLP

23.2* Consent of Netherland, Sewell & Associates, Inc.

23.3* Consent of Data & Consulting Services, Division of Schlumberger Technology Corporation

23.4* Consent of Lee Keeling and Associates, Inc.

23.5* Consent of Ryder Scott Company L.P.

23.6*	Consent of LaRoche Petroleum Consultants, Ltd.
31.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.
† Management contract or compensatory plan or arrangement.

SIGNATURES

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

CHESAPEAKE ENERGY CORPORATION

By /S/ AUBREY K. MCCLENDON

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

Date: March 1, 2007

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

Signature	Capacity	Date
/s/ AUBREY K. MCCLENDON **Aubrey K. McClendon**	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	March 1, 2007
/s/ MARCUS C. ROWLAND **Marcus C. Rowland**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2007
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President—Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 1, 2007
/s/ RICHARD K. DAVIDSON **Richard K. Davidson**	Director	March 1, 2007
/s/ FRANK KEATING **Frank Keating**	Director	March 1, 2007
/s/ BREENE M. KERR **Breene M. Kerr**	Director	March 1, 2007
/s/ CHARLES T. MAXWELL **Charles T. Maxwell**	Director	March 1, 2007
/s/ MERRILL A. MILLER, JR **Merrill A. Miller, Jr.**	Director	March 1, 2007
/s/ DON NICKLES **Don Nickles**	Director	March 1, 2007
/s/ FREDERICK B. WHITTEMORE **Frederick B. Whittemore**	Director	March 1, 2007

Exhibit 31.1

CERTIFICATION

I, Aubrey K. McClendon, certify that:

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

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

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

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

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

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 1, 2007

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

Exhibit 31.2

CERTIFICATION

I, Marcus C. Rowland, certify that:

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

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

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

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

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

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 1, 2007

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

Exhibit 32.1

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

In connection with the Annual Report of Chesapeake Energy Corporation (the "Company") on Form 10-K for the period ended December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Aubrey K. McClendon, Chairman and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: March 1, 2007

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

Exhibit 32.2

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

In connection with the Annual Report of Chesapeake Energy Corporation (the “Company”) on Form 10-K for the period ended December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Marcus C. Rowland, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: March 1, 2007

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