CHESAPEAKE ENERGY CORP
Form 10-K
March 14, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2005

¨ 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	**73-1395733**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
6100 North Western Avenue	
Oklahoma City, Oklahoma	**73118**
(Address of principal executive offices)	**(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
7.0% 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
6.25% Senior Notes due 2018	New York Stock Exchange
6.0% Cumulative Convertible Preferred Stock	New York Stock Exchange
5.0% Cumulative Convertible Preferred Stock (Series 2003)	New York Stock Exchange
4.5% Cumulative 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 x 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 x

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

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

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 x 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 x

The aggregate market value of our common stock held by non-affiliates on June 30, 2005 was $6,327,096,262. At March 10, 2006, there were 373,622,333 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2006 Annual Meeting of Shareholders are incorporated by reference in Part III.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

2005 ANNUAL REPORT ON FORM 10-K

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PART I

ITEM 1. *Business*

General

We are the second largest independent producer of natural gas in the United States, owning interests in approximately 30,600 producing oil and gas wells that are currently producing approximately 1.5 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves primarily in the southwestern U.S. and secondarily in the Appalachian Basin of the eastern U.S. Our most important operating area has historically been the Mid-Continent region of the U.S., which includes Oklahoma, Arkansas, Kansas and the Texas Panhandle, and is where 51% of our proved oil and natural gas reserves are located. During the past four years, we have also built significant positions in the South Texas and Texas Gulf Coast regions, the Permian Basin of West Texas and eastern New Mexico, the Barnett Shale area of north-central Texas, the Ark-La-Tex area of East Texas and northern Louisiana and most recently, the emerging Fayetteville Shale play located in Arkansas. As a result of our recent acquisition of the holding company of Columbia Natural Resources, LLC and certain affiliated entities (CNR), we now have a significant presence in the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York.

As of December 31, 2005, we had 7.5 tcfe of proved reserves, of which 92% are natural gas and all of which are onshore. During 2005, we replaced our 469 bcfe of production with an internally estimated 3.088 tcfe of new proved reserves, for a reserve replacement rate of 659%. Reserve replacement through the drillbit was 1.047 tcfe, or 223% of production (including a positive 17 bcfe from performance revisions and a positive 24 bcfe from oil and natural gas price increases), and reserve replacement through acquisitions was 2.041 tcfe, or 436% of production. Our proved reserves grew by 53% during 2005, from 4.9 tcfe to 7.5 tcfe.

During 2005, we led the nation in drilling activity with an average utilization of 73 operated rigs and 66 non-operated rigs. Through this drilling activity, we drilled 902 (686 net) operated wells and participated in another 1,066 (130 net) wells operated by other companies. We added approximately 1.047 tcfe of proved oil and natural gas reserves through our drilling efforts. Our success rate was 98% for operated wells and 95% for non-operated wells. As of December 31, 2005, our proved developed reserves were 65% of our total proved reserves. In 2005, we added approximately 1,200 new employees and invested $362 million in leasehold (exclusive of leases acquired through 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, 2005, we have been one of the most active consolidators of onshore U.S. natural gas assets, having purchased approximately 5.9 tcfe of proved reserves, at a total cost of approximately $10.3 billion (including $2.2 billion for unproved leasehold, but excluding $809 million of deferred taxes established in connection with certain corporate acquisitions) for a per proved mcfe acquisition cost of $1.37.

During 2005, we were especially active in the acquisitions market. Acquisition expenditures totaled $4.9 billion through December 31, 2005 (including $1.4 billion for unproved leasehold, but excluding $252 million of deferred taxes established in connection with certain corporate acquisitions). Through these acquisitions, we have acquired an internally estimated 2.0 tcfe of proved oil and natural gas reserves at a per proved mcfe acquisition cost of $1.74.

On November 14, 2005, we acquired CNR and its significant natural gas reserves, acreage and mid-stream assets for approximately $3.02 billion, of which $2.2 billion was in cash and $0.82 billion was in assumed liabilities related to CNR s prepaid sales agreement, hedging positions and other liabilities. The CNR assets consist of 125 mmcfe per day of natural gas production, 1.3 tcfe of proved reserves and approximately 3.2 million net acres of U.S. oil and gas leasehold, which we estimate have over 9,000 additional undrilled locations with reserve potential. CNR also owns extensive mid-stream natural gas assets, including over 6,500 miles of natural gas gathering lines.

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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.

Recent Developments

In the first quarter of 2006, we have continued to execute our acquisition and financing strategy through the following transactions, in which we:

- acquired oil and natural gas assets from private companies located in the Barnett Shale, South Texas, Permian Basin, Mid-Continent and Ark-La-Tex regions for an aggregate purchase price of approximately $640 million in cash and expect to close another acquisition for a cash purchase price of approximately $60 million by March 31, 2006;
- acquired a privately-held Oklahoma-based trucking company for $48 million;
- 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 finance our recent acquisitions;
- amended and restated our revolving bank credit facility, increasing the commitments to $2.0 billion and extending the maturity date to February 2011;
- sold our investment in Pioneer Drilling Company (AMEX:PDC) common stock for cash proceeds of $159 million and a pre-tax gain of $116 million; and
- acquired 13 drilling rigs and related assets through our wholly-owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-held drilling contractor with operations in East Texas and North Louisiana, for $150 million.

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 has agreed to act as a consultant to Chesapeake for a period of six months from the effective date of his resignation, pursuant to a resignation agreement, to assist in the transition of his responsibilities. During the term of his consulting agreement, Mr. Ward will receive no cash compensation but will be provided support staff for personal administrative and accounting services together with access to the company s fractional shares in aircraft in accordance with historical practices. The resignation agreement provides for the immediate vesting of all of Mr. Ward s unvested stock options and restricted stock on February 10, 2006. As a result of such vesting, 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 became immediately vested. As a result, the company expects to incur a non-cash after-tax charge of approximately $31.8 million in the first quarter 2006. Mr. Ward will have until May 10, 2006 to exercise the stock options granted to him by the company.

Business Strategy

Since our inception in 1989, our goal has been to create value for investors by building one of the largest onshore natural gas resource bases in the United States. For much of the past eight years, our strategy to accomplish this goal has been to build the dominant operating position in the Mid-Continent region, the third largest gas supply region in the U.S. In building our industry-leading position in the Mid-Continent, 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. In 2002, we began expanding our focus from the Mid-Continent to other regions where we believed we could extend our successful strategy. To date, those areas have included the South Texas and Texas Gulf Coast regions, the Permian Basin of West

Texas and eastern New Mexico, the Barnett Shale area of north-central Texas, the Ark-La-Tex area of East Texas and northern Louisiana, and, through our recent CNR acquisition, the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York. We believe significant elements of our successful Mid-Continent strategy of acquisition, exploitation, extension and exploration have been or will be successfully transferred to these areas.

Key elements of this business strategy are further explained below:

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, 2005, we have acquired $10.3 billion of oil and gas properties at an estimated average cost of $1.37 per mcfe of proved reserves. Included in this amount is $2.2 billion for unproved leasehold, but excluded from this amount is $809 million, or $0.14 per mcfe of proved reserves, of deferred taxes established in connection with certain corporate acquisitions. The vast 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.

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 78 operated drilling rigs and 82 non-operated drilling rigs to conduct the most active drilling program in the United States. 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 seven years, we have been aggressively 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 been generally declining during the past five years, we are one of the few large-cap companies that have been able to increase production, which we have successfully achieved for the past 16 consecutive years and 18 consecutive quarters. We believe key elements of the success and scale of our drilling programs have been our early recognition that gas prices were likely to move higher in the U.S. in the post-1999 period accompanied by our willingness to aggressively 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 value creation in a successful large-scale drilling program.

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 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 Mountain basins in current U.S. 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 93% over the past sixteen 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 our other operating areas possess many of these same favorable characteristics and our goal is to become or remain a top five producer in each of our operating areas.

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 the extensive and competitive services, gas processing and transportation infrastructures that exist in our key operating areas. As of December 31, 2005, we operated approximately 18,200 wells, or approximately 80% of our daily production.

Improve our Balance Sheet. We have made significant progress in improving our balance sheet over the past seven years. From December 31, 1998 through December 31, 2005, we have increased our shareholders equity by $6.4 billion through a combination of earnings and common and preferred equity issuances. As of December 31, 2005, our debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 47%, compared to 49% as of December 31, 2004 and 137% as of December 31, 1998. We plan to continue improving our balance sheet in the years ahead.

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 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 10% to 20% per year, with growth at an annual rate of 5% to 10% generated organically through the drillbit and the remaining growth generated through acquisitions. We have reached or exceeded this overall production goal in 11 of our 13 years as a public company.

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 years. In addition, we believe we are the sixth largest producer of natural gas in the U.S. (second among independents) and among the largest owners of proved U.S. natural gas reserves. 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. As of December 31, 2005, we operated properties accounting for approximately 80% of our daily production volumes. This large percentage of operated properties provides us with a high degree of operating flexibility and cost control.

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 2005, our operating costs per unit of production were $1.26 per mcfe, which consisted of general and administrative expenses of $0.14 per mcfe (including non-cash stock-based compensation of $0.03 per mcfe), production expenses of $0.68 per mcfe and production taxes of $0.44 per mcfe. We believe this is one of the lowest cost structures among publicly-traded, large-cap independent oil and natural gas producers.

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, favorable basis differentials to benchmark commodity prices, well-developed oil and gas transportation infrastructures and considerable potential for further consolidation of assets. Since 1998, we have completed $10.3 billion in acquisitions at an estimated average cost of $1.37 per mcfe of proved reserves. Included in this amount is $2.2 billion for unproved leasehold, but excluded from this amount is $809 million, or $0.14

per mcfe of proved reserves, of deferred taxes established in connection with certain corporate acquisitions. 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.

Large Inventory of Drilling Projects. During the 16 years since our inception, we have been among the five most active drillers of new wells in the United States. Presently, we are the most active driller in the U.S. (with 78 operated and 82 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 reservoir conditions. In addition, we believe that our large 11.6 million acre 3-D seismic inventory, much of which is proprietary to us, provides significant informational advantages over our competitors. As a result of our aggressive leasehold acquisition and seismic acquisition strategies, we have been able to accumulate a U.S. onshore leasehold position of approximately 8.5 million net acres and have acquired rights to 11.6 million acres of onshore 3-D seismic data to help evaluate our expansive acreage inventory. On this very large acreage position, our technical teams have identified approximately 28,000 exploratory and developmental drill sites, representing a backlog of more than ten years of future drilling opportunities at current drilling rates.

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. Excluding hedges assumed in the acquisition of CNR, we currently have gas hedges in place covering 71% of our anticipated gas production for 2006, 36% of our anticipated gas production for 2007 and 22% of our anticipated gas production for 2008 at average NYMEX prices of $9.43, $9.85 and $9.10 per mcf, respectively (excluding collars and options). In addition, we have 63% of our anticipated oil production hedged for 2006, 22% of our anticipated oil production hedged for 2007 and 14% of our anticipated oil production hedged for 2008 at average NYMEX prices of $61.02, $62.42 and $65.48 per barrel of oil, respectively.

Entrepreneurial Management. Chesapeake was formed in 1989 with an initial capitalization of $50,000 and fewer than ten employees. Since then, management has guided the company through various operational and industry challenges and extremes of oil and gas prices to create the second largest independent U.S. producer of natural gas with approximately 2,900 employees and an enterprise value of approximately $20 billion. Our CEO and co-founder, Aubrey K. McClendon, has been in the oil and gas industry for 23 years and beneficially owns, as of March 10, 2006, approximately 22.4 million shares of our common stock.

Properties

Chesapeake focuses its natural gas exploration, development and acquisition efforts in one primary operating area and in four secondary operating areas: (i) the Mid-Continent (consisting of Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle), representing 51% of our proved reserves, (ii) the South Texas and Texas Gulf Coast region, representing 8% of our proved reserves, (iii) the Barnett Shale area of north-central Texas and the Ark-La-Tex area of central and East Texas and northern Louisiana, representing 14% of our proved reserves, (iv) the Permian Basin of western Texas and eastern New Mexico, representing 9% of our proved reserves, and (v) the Appalachian basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York, representing 17% of our proved reserves.

Chesapeake s strategy for 2006 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 2006 production will be between 576 bcfe and 586 bcfe. We have budgeted

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$3.0 to $3.2 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. Our budget is frequently adjusted based on changes in oil and 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 3.798 tcfe represented 51% of our total proved reserves as of December 31, 2005, and this area produced 298 bcfe, or 64%, of our 2005 production. During 2005, we invested approximately $1.102 billion to drill 1,442 (498 net) wells in the Mid-Continent. We anticipate spending approximately 35% of our total budget for exploration and development activities in the Mid-Continent region during 2006.

South Texas and Texas Gulf Coast. Chesapeake s South Texas and Texas Gulf Coast proved reserves represented 622 bcfe, or 8%, of our total proved reserves as of December 31, 2005. During 2005, the South Texas and Texas Gulf Coast assets produced 64 bcfe, or 14%, of our total production. During 2005, we invested approximately $239.1 million to drill 115 (80 net) wells in the South Texas and Texas Gulf Coast region. We anticipate spending approximately 10% of our total budget for exploration and development activities in the South Texas and Texas Gulf Coast region during 2006.

Ark-La-Tex and Barnett Shale. Chesapeake s Ark-La-Tex and Barnett Shale proved reserves represented 1.069 tcfe, or 14%, of our total proved reserves as of December 31, 2005. During 2005, the Ark-La-Tex and Barnett Shale assets produced 58 bcfe, or 12%, of our total production. During 2005, we invested approximately $326.9 million to drill 257 (171 net) wells in the Ark-La-Tex and Barnett Shale regions. For 2006, we anticipate spending approximately 33% of our total budget for exploration and development activities in the Ark-La-Tex and Barnett Shale regions.

Permian Basin. Chesapeake s Permian Basin proved reserves represented 693 bcfe, or 9%, of our total proved reserves as of December 31, 2005. During 2005, the Permian assets produced 40 bcfe, or 9%, of our total production. During 2005, we invested approximately $265.9 million to drill 139 (56 net) wells in the Permian Basin. For 2006, we anticipate spending approximately 15% of our total budget for exploration and development activities in the Permian Basin.

Appalachian Basin. Chesapeake s Appalachian Basin proved reserves represented 1.296 tcfe, or 17%, of our total proved reserves as of December 31, 2005. During 2005, the Appalachian assets produced 6 bcfe, or 1%, of our total production, which was not acquired until November 14, 2005. During 2005, we invested approximately $8 million to drill 15 (11 net) wells in the Appalachian Basin. For 2006, we anticipate spending approximately 7% of our total budget for exploration and development activities in the Appalachian Basin.

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Drilling Activity

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

	2005				2004				2003			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Development:												
Productive	1,736	97%	735	97%	1,239	97%	463	98%	958	96%	401	97%
Non-productive	51	3	21	3	34	3	9	2	37	4	11	3
Total	1,787	100%	756	100%	1,273	100%	472	100%	995	100%	412	100%
Exploratory:												
Productive	177	98%	57	95%	164	92%	67	91%	76	86%	36	83%
Non-productive	4	2	3	5	14	8	7	9	12	14	8	17
Total	181	100%	60	100%	178	100%	74	100%	88	100%	44	100%

The following table shows the wells we drilled by area:

	2005		2004		2003	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Mid-Continent	1,442	498	1,195	417	984	403
South Texas and Texas Gulf Coast	115	80	67	38	55	25
Ark-La-Tex and Barnett Shale	257	171	82	36		
Permian	139	56	107	55	44	28
Appalachia	15	11				
Total	1,968	816	1,451	546	1083	456

At December 31, 2005, we had 154 (67 net) wells in process. As of December 31, 2005, we owned 18 drilling rigs dedicated to drilling wells operated by Chesapeake. An additional 26 drilling rigs are under construction or on order, and we purchased 13 drilling rigs in February 2006. Our drilling business is conducted through our wholly owned subsidiary, Nomac Drilling Corporation.

Well Data

At December 31, 2005, we had interests in approximately 30,600 (16,985 net) producing wells, including properties in which we held an overriding royalty interest, of which 3,100 (1,360 net) were classified as primarily oil producing wells and 27,500 (15,625 net) were classified as primarily gas producing wells. Chesapeake operated approximately 18,200 of its 30,600 producing wells. During 2005, we drilled 902 (686 net) wells and participated in another 1,066 (130 net) wells operated by other companies. We operate approximately 80% of our current daily production volumes.

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Production, Sales, Prices and Expenses

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

	2005	2004	2003
Net Production:			
Oil (mbbl)	7,698	6,764	4,665
Gas (mmcf)	422,389	322,009	240,366
Gas equivalent (mmcfe)	468,577	362,593	268,356
Oil and Gas Sales ($ in thousands):			
Oil sales	$ 401,845	$ 260,915	$ 132,630
Oil derivatives realized gains (losses)	(34,132)	(69,267)	(12,058)
Oil derivatives unrealized gains (losses)	4,374	3,454	(9,440)
Total oil sales	$ 372,087	$ 195,102	$ 111,132
Gas sales	$ 3,231,286	$ 1,789,275	$ 1,171,050
Gas derivatives realized gains (losses)	(367,551)	(85,634)	(5,331)
Gas derivatives unrealized gains (losses)	36,763	37,433	19,971
Total gas sales	$ 2,900,498	$ 1,741,074	$ 1,185,690
Total oil and gas sales	$ 3,272,585	$ 1,936,176	$ 1,296,822
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 52.20	$ 38.57	$ 28.43
Gas ($ per mcf)	$ 7.65	$ 5.56	$ 4.87
Gas equivalent ($ per mcfe)	$ 7.75	$ 5.65	$ 4.86
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 47.77	$ 28.33	$ 25.85
Gas ($ per mcf)	$ 6.78	$ 5.29	$ 4.85
Gas equivalent ($ per mcfe)	$ 6.90	$ 5.23	$ 4.79
Expenses ($ per mcfe):			
Production expenses	$ 0.68	$ 0.56	$ 0.51
Production taxes	$ 0.44	$ 0.29	$ 0.29
General and administrative expenses	$ 0.14	$ 0.10	$ 0.09
Oil and gas depreciation, depletion and amortization	$ 1.91	$ 1.61	$ 1.38
Depreciation and amortization of other assets	$ 0.11	$ 0.08	$ 0.06
Interest expense (a)	$ 0.47	$ 0.45	$ 0.55

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

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Oil and Gas Reserves

The tables below set forth information as of December 31, 2005 with respect to our estimated proved reserves, the associated estimated future net revenue and present value (discounted at 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 gas reserves we own.

	December 31, 2005		
	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
Proved developed	76,238	4,442,270	4,899,694
Proved undeveloped	27,085	2,458,484	2,620,996
Total proved	103,323	6,900,754	7,520,690

	Proved Developed	Proved Undeveloped ($ in thousands)	Total Proved
Estimated future net revenue (a)	$ 32,435,228	$ 14,376,458	$ 46,811,686
Present value of future net revenue (a)	$ 16,271,138	$ 6,662,456	$ 22,933,594
Standardized measure (a) (b)			$ 15,967,911

	Oil (mbbl)	Gas (mmcf)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value ($ in thousands)
Mid-Continent	48,915	3,504,653	3,798,216	51%	$ 11,308,766
South Texas and Texas Gulf Coast	3,308	602,551	622,399	8	2,459,379
Ark-La-Tex and Barnett Shale	6,379	1,030,962	1,069,236	14	3,551,565
Permian	39,126	457,811	692,570	9	2,040,175
Appalachia	1,094	1,289,919	1,296,482	17	3,462,744
Other	4,501	14,858	41,787	1	110,965
Total	103,323	6,900,754	7,520,690	100%	$ 22,933,594(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, 2005. The prices used in the external and internal reports yield weighted average wellhead prices of $56.41 per barrel of oil and $8.76 per mcf of gas. These prices should not be interpreted as a prediction of future prices. 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 future income tax expenses ($6.97 billion as of December 31, 2005).

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.

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As of December 31, 2005, our reserve estimates included 2.621 tcfe of reserves classified as proved undeveloped (PUD). Of this amount, approximately 56% (by volume) were initially classified as PUDs in 2005, 29% were initially classified as PUDs in 2004, 5% were initially classified as PUDs in 2003, and the remaining 10% were initially classified as PUDs prior to 2003. Of our proved developed reserves, 555 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 $14.4 billion at December 31, 2005, and the $6.7 billion present value thereof, has been calculated assuming that we will expend approximately $4.3 billion to develop these reserves. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, product prices and the availability of capital, but we have projected to incur $1.8 billion in 2006, $1.1 billion in 2007, $0.7 billion in 2008 and $0.7 billion in 2009 and beyond. 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 78% of our proved reserves (by volume) at year-end 2005. 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 25%, Data and Consulting Services, Division of Schlumberger Technology Corporation evaluated 16%, Lee Keeling and Associates, Inc. evaluated 15%, Ryder Scott Company L.P. evaluated 12%, LaRoche Petroleum Consultants, Ltd. evaluated 8%, and H. J. Gruy and Associates, Inc. evaluated 2% of our estimated proved reserves by volume at December 31, 2005. Of the 41,880 properties included in the 2005 reserve reports, the estimates prepared by the independent firms covered approximately 16,400 properties, or 39% of the total well count. Because, in management s opinion, it is cost prohibitive for third-party engineers to evaluate all of our wells, we have prepared reserve forecasts for approximately 22% 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.

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

Chesapeake s ownership interest used in calculating proved reserves and the associated estimated future net revenue was determined after giving effect to the assumed maximum participation by other parties to our farmout and participation agreements. The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for oil and gas production sold subsequent to December 31, 2005. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond Chesapeake s control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates, and such revisions may be material. Accordingly, reserve estimates are often different from the actual quantities of oil and gas that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and 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

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in a change in the December 31, 2005 present value of estimated future net revenue of our proved reserves of approximately $315 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, 2005, 2004 and 2003, 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, 2005	December 31, 2004	December 31, 2003
	($ in thousands)		
Acquisition of properties:			
Proved properties	$ 3,554,651	$ 1,541,920	$ 1,110,077
Unproved properties	1,375,675	570,495	198,394
Deferred income taxes	251,722	463,949	(4,903)
Total	5,182,048	2,576,364	1,303,568
Development costs:			
Development drilling (a)	1,566,730	863,268	474,355
Leasehold acquisition costs	290,946	110,530	84,984
Asset retirement obligation and other (b)	52,619	41,924	54,657
Total	1,910,295	1,015,722	613,996
Exploration costs:			
Exploratory drilling	253,341	128,635	103,424
Geological and geophysical costs (c)	70,901	55,618	42,736
Total	324,242	184,253	146,160
Sales of oil and gas properties	(9,769)	(12,048)	(22,156)
Total	$ 7,406,816	$ 3,764,291	$ 2,041,568

(a) Includes capitalized internal cost of $94.1 million, $45.4 million and $30.9 million, respectively.

(b) The 2003 amount includes $24.1 million of asset retirement costs recorded as a result of implementation of SFAS 143 effective January 1, 2003.

(c) Includes capitalized internal cost of $8.1 million, $6.3 million and $4.6 million, respectively.

Our development costs included $671 million, $333 million and $229 million in 2005, 2004 and 2003, respectively, related to properties carried as proved undeveloped locations in the prior year s reserve reports. Included in our reserve report as of December 31, 2005 are estimated future development costs of $4.3 billion related to the development of proved undeveloped reserves ($1.8 billion in 2006, $1.1 billion in 2007, $0.7 billion in 2008 and $0.7 billion in 2009 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.

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A summary of our development, exploration, acquisition and divestiture activities in 2005 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	1,442	498	$ 1,102,099	$ 166,281	$ 178,169	$ 217,238	$ (214)	$ 1,663,573
South Texas and Texas Gulf Coast	115	80	239,107	87,418	224,947	215,166		766,638
Ark-La-Tex and Barnett Shale	257	171	359,206	7,816	350,416	666,309		1,383,747
Permian	139	56	233,597	29,452	114,874	339,838	(9,555)	708,206
Appalachia	15	11	7,673		506,881	2,367,835		2,882,389
Other			1,909	(21)	388	(13)		2,263
Total	1,968	816	$ 1,943,591	$ 290,946	$ 1,375,675	$ 3,806,373	$ (9,769)	$ 7,406,816

(a) Includes $252 million of deferred tax adjustments.

Acreage

The following table sets forth as of December 31, 2005 the gross and net acres of both developed and undeveloped oil and gas leases which we hold. Gross acres are the total number of acres in which we own a working interest. Net acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our options to acquire additional leasehold which have not been exercised.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	3,636,949	1,723,203	3,497,527	1,609,322	7,134,476	3,332,525
South Texas and Texas Gulf Coast	304,027	172,915	352,121	229,615	656,148	402,530
Ark-La-Tex and Barnett Shale	164,589	116,239	317,082	220,316	481,671	336,555
Permian	175,204	110,571	726,714	459,224	901,918	569,795
Appalachia	506,828	478,791	2,907,116	2,681,685	3,413,944	3,160,476
Canada			673,689	614,616	673,689	614,616
Other	43,424	18,607	95,240	76,084	138,664	94,691
Total	4,831,021	2,620,326	8,569,489	5,890,862	13,400,510	8,511,188

Marketing

Chesapeake s oil production is generally sold under market sensitive or spot price contracts. 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 gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. The revenue we receive from the sale of natural gas liquids is included in oil sales. Under percentage-of-index contracts, the price per mmbtu we receive for our gas is tied to indexes published in *Inside FERC* or *Gas Daily*. Although exact percentages vary daily, as of February 2006, approximately 70% of our natural gas production was sold under short-term contracts at market-sensitive or spot prices.

During 2005, sales to Eagle Energy Partners I, L.P. (Eagle) of $851 million accounted for 18% of our total revenues. 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 in 2005.

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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, 2005, Nomac owned 18 drilling rigs dedicated to drilling wells operated by Chesapeake and had an additional 26 rigs under construction or on order. The 18 drilling rigs which are currently drilling company-operated wells have depth ratings between 7,500 and 23,000 feet and range in drilling horsepower from 650 to 2,000. These drilling rigs are currently operating in the Mid-Continent region of Oklahoma and Texas. In February 2006, Nomac acquired 13 drilling rigs from privately-held Martex Drilling Corporation for $150 million. The acquisition of Martex will bring Nomac s rig fleet to 57 drilling rigs when all rigs on order are delivered. As the Martex drilling rigs currently under contract become available, they will be used for drilling company-operated wells.

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 and are comprised of approximately 7,600 miles of gathering lines, treating facilities and processing facilities which provide service to approximately 8,775 wells.

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 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 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 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

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unitization or pooling of oil and 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 gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amount of oil and gas we can produce and to limit the number of wells or the locations at which we can drill.

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. All of the company s sales of oil, natural gas liquids and natural gas are currently deregulated, 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 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, drilling, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products, water and air pollution control procedures, and the remediation of petroleum-product contamination. In addition, our operations 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.

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We have made and will continue to make expenditures to comply with environmental regulations and requirements. These are necessary business costs in the oil and gas industry. Although we are not fully insured against all environmental risks, we maintain insurance coverage which we believe is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental laws and regulations, as well as claims for damages to property or persons resulting from company operations, could result in substantial costs and liabilities, including civil and criminal penalties, to Chesapeake. We believe we are in 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 $545.1 million in 2005 compared to income tax expense of $289.8 million in 2004 and $191.8 million in 2003. Our effective income tax rate was 36.5% in 2005 compared to 36% in 2004 and 38% in 2003. The increase in 2005 reflected the impact state income taxes and permanent differences had on our overall effective rate. We expect our effective income tax rate will increase to 38% in 2006 to reflect our current assessment of expected increases in state income taxes and permanent differences.

At December 31, 2005, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $564.5 million. We also had approximately $169.6 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $12.3 million of percentage depletion carryforwards. The NOL carryforwards expire from 2012 through 2025. 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, 2005 and any related limitations:

	Net Operating Losses		
			Annual
	Total	**Limited**	**Limitation**
		($ in thousands)	
Net operating loss	$ 564,451	$ 49,284	$ 27,754
AMT net operating loss	$ 169,635	$ 11,220	$ 6,652

Although no assurances can be made, we do not believe that an ownership change has occurred as of December 31, 2005. 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

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

Operating Hazards and Insurance

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

Chesapeake maintains a $50 million oil and gas lease operator policy that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. There is no assurance that this insurance will be adequate to cover all losses or exposure to liability. Chesapeake also carries a $175 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:

- Illinois: Chicago;
- Kansas: Garden City;
- Kentucky: Gray, Elkhorn City, Hueysville, Inez and Prestonburg;
- Louisiana: Cheneyville and Shreveport;
- New Mexico: Eunice and Hobbs;
- New York: Hammondsport;

Oklahoma: Arkoma, Billings, El Reno, Kingfisher, Lindsay, Waynoka, Weatherford, Wilburton, Forgan and Sayre;

Tennessee: Egan;

Texas: Borger, Dumas, College Station, Midland, Cleburne, Goliad, Ozona, Tyler, Victoria and Zapata; and

West Virginia: Branchland, Buckhannon, Cedar Grove, Charleston, Clendenin, Kermit and Tad.

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Employees

Chesapeake had 2,885 employees as of December 31, 2005, which includes 429 employed by our drilling subsidiary, Nomac Drilling Corporation. As a result of the CNR acquisition, approximately 140 of our employees are covered by a collective bargaining agreement. We believe our employee relations are good.

Glossary of Oil and Gas Terms

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of gas equivalent.

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

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

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

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

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

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

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

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

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

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

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

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

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

Mbtu. One thousand btus.

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Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of gas equivalent.

Net Acres or Net Wells. The sum of the fractional working 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 gas reserves, present value or PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

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

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and 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.

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 on page 107. 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.

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.

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

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 gas equivalent.

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

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

ITEM 1A. *Risk Factors*

Our business has many risks. Any of the following factors could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock, preferred stock or senior notes could decline. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

Oil and 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 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.

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

- worldwide and domestic supplies of oil and gas;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- 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 gas price movements with any certainty. Declines in oil and gas prices would not only reduce revenue, but could reduce the amount of oil and gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and gas prices do not necessarily move in tandem. Because approximately 92% of our reserves at December 31, 2005 are 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, 2005, we had long-term indebtedness of approximately $5.5 billion, with $72.0 million drawn under our revolving bank credit facility. Our long-term indebtedness represented 47% of our total book capitalization at December 31, 2005. As of March 10, 2006, we had approximately $402 million 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 peer 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.

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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 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 gas, and our success in developing, acquiring and producing new reserves. If revenue were to decrease as a result of lower oil and gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, 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 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 35% of our total estimated proved reserves (by volume) at December 31, 2005 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will

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require significant capital expenditures and successful drilling operations. Our reserve estimates reflect that our production rate on producing properties will decline approximately 24% from 2006 to 2007. 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 gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

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

At December 31, 2005, approximately 35% 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 $1.8 billion in 2006. 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, 2005 present value is based on weighted average oil and natural gas wellhead prices of $56.41 per barrel of oil and $8.76 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 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 recent growth is due in 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 gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

We were not entitled to contractual indemnification for the majority of pre-closing liabilities, including environmental liabilities, in our recent acquisition of CNR. We acquired CNR on an as is basis with very limited remedies for breaches of representations and warranties. We might incur significant liabilities relating to CNR in the future which we have not yet identified or cannot quantify at this time.

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. As a result of our recent acquisition of CNR, we now have a significant presence in the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York. We have not previously developed or explored for oil and natural gas in this part of the U.S.

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

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

- 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 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 gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. The full cost ceiling is evaluated at the end of each quarter using the prices for oil and gas at that date, adjusted for the impact of derivatives accounted for as cash flow hedges. A significant decline in oil and gas prices from current levels, or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

Our hedging activities may reduce the realized prices received for our oil and 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 gas, we enter into oil and 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 gas revenues in the future. The fair value of our oil and gas derivative instruments outstanding as of December 31, 2005 was a liability of approximately $945.8 million. In addition, our commodity price risk management transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

our production is less than expected;

there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; or

the counterparties to our contracts fail to perform under the contracts.

Some of our commodity price and interest rate risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations exceed certain levels. As of December 31, 2005, we were required to post a total of $50 million of collateral with our counterparties through letters of credit issued under our bank credit facility with respect to commodity price and financial risk management transactions. As of March 10, 2006, we were required to post $50 million of collateral with our counterparties through letters of credit. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and highly volatile natural gas and oil prices.

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

Our amended and restated revolving bank credit facility limits our borrowings to the lesser of the borrowing base (currently $2.5 billion) and the commitment (currently $2.0 billion). The borrowing base is determined periodically at the discretion of the banks and is based in part on oil and gas prices. Additionally, some of our indentures contain covenants limiting our ability to incur indebtedness in addition to that incurred under our bank credit facility. These indentures limit our ability to incur additional indebtedness unless we meet one of two alternative tests. The first alternative is based on 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 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. As of the date of this report, we are permitted to incur significant additional indebtedness under both of these debt incurrence tests. Lower oil and gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

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

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

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and penalties; and
- suspension of operations.

Our liability for environmental hazards includes those created either by the previous owners of properties that we purchase or lease or by acquired companies prior to the date we acquire them. We 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.

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 currently involved in various disputes incidental to our business operations. We believe that the final resolution of currently pending or threatened litigation is not likely to have a material adverse effect on our financial position or results of operations or cash flows.

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

Not applicable.

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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, 2005:		
First Quarter	$ 23.65	$ 15.06
Second Quarter	24.00	17.74
Third Quarter	38.98	22.90
Fourth Quarter	40.20	26.59
Year ended December 31, 2004:		
First Quarter	$ 13.98	$ 11.70
Second Quarter	15.05	12.68
Third Quarter	16.24	13.69
Fourth Quarter	18.31	15.17

At March 10, 2006, there were 1,473 holders of record of our common stock and approximately 322,000 beneficial owners.

Dividends

The following table sets forth the amount of dividends per share declared on Chesapeake common stock during 2005 and 2004:

	2005	2004
First Quarter	$ 0.045	$ 0.035
Second Quarter	0.050	0.045
Third Quarter	0.050	0.045
Fourth 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, 2005, our coverage ratio for purposes of the debt incurrence test under the relevant indentures was 5.45 to 1, compared to 2.25 to 1 required in our indentures. Our adjusted consolidated net tangible assets under the relevant indentures exceeded 200% of our total indebtedness, as required in our indentures, by more than $5.2 billion.

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The following table presents information about repurchases of our common stock during the three months ended December 31, 2005:

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, 2005 through October 31, 2005	28,227	$ 32.461		
November 1, 2005 through November 30, 2005	26,596	$ 29.890		
December 1, 2005 through December 31, 2005	22,952	$ 31.965		
Total	77,775	$ 31.435		

(a) Includes 75,224 shares purchased in the open market for the matching contributions we make to our 401(k) plans and the surrender to the company of 2,551 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 company contributions. There are no other repurchase plans or programs currently authorized by the board of directors.

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

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2005, 2004, 2003, 2002 and 2001. 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 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,				
	2005	2004	2003	2002	2001
	($ in thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Oil and gas sales	$ 3,272,585	$ 1,936,176	$ 1,296,822	$ 568,187	$ 820,318
Oil and gas marketing sales	1,392,705	773,092	420,610	170,315	148,733
Total revenues	4,665,290	2,709,268	1,717,432	738,502	969,051
Operating costs:					
Production expenses	316,956	204,821	137,583	98,191	75,374
Production taxes	207,898	103,931	77,893	30,101	33,010
General and administrative expenses	64,272	37,045	23,753	17,618	14,449
Oil and gas marketing expenses	1,358,003	755,314	410,288	165,736	144,373
Oil and gas depreciation, depletion and amortization	894,035	582,137	369,465	221,189	172,902
Depreciation and amortization of other assets	50,966	29,185	16,793	14,009	8,663
Provision for legal settlements		4,500	6,402		
Total operating costs	2,892,130	1,716,933	1,042,177	546,844	448,771
Income from operations	1,773,160	992,335	675,255	191,658	520,280
Other income (expense):					
Interest and other income	10,452	4,476	2,827	7,340	2,877
Interest expense	(219,800)	(167,328)	(154,356)	(112,031)	(98,321)
Loss on repurchases or exchanges of Chesapeake debt	(70,419)	(24,557)	(20,759)	(2,626)	(76,667)
Loss on investment in Seven Seas Petroleum, Inc.			(2,015)	(17,201)	
Impairments of investments in securities					(10,079)
Gain on sale of Canadian subsidiary					27,000
Gothic standby credit facility costs					(3,392)
Total other income (expense)	(279,767)	(187,409)	(174,303)	(124,518)	(158,582)
Income before income taxes and cumulative effect of accounting change	1,493,393	804,926	500,952	67,140	361,698
Income tax expense (benefit):					
Current			5,000	(1,822)	3,565
Deferred	545,091	289,771	185,360	28,676	140,727
Total income tax expense	545,091	289,771	190,360	26,854	144,292
Net income before cumulative effect of accounting change, net of tax	948,302	515,155	310,592	40,286	217,406
Cumulative effect of accounting change, net of income taxes of $1,464,000			2,389		
Net Income	948,302	515,155	312,981	40,286	217,406
Preferred stock dividends	(41,813)	(39,506)	(22,469)	(10,117)	(2,050)
Loss on conversion/exchange of preferred stock	(26,874)	(36,678)			

Net income available to common shareholders	$	879,615	$	438,971	$	290,512	$	30,169	$	215,356
Earnings per common share basic:										
Income before cumulative effect of accounting change	$	2.73	$	1.73	$	1.36	$	0.18	$	1.33
Cumulative effect of accounting change						0.02				
	$	2.73	$	1.73	$	1.38	$	0.18	$	1.33
Earnings per common share assuming dilution:										
Income before cumulative effect of accounting change	$	2.51	$	1.53	$	1.20	$	0.17	$	1.25
Cumulative effect of accounting change						0.01				
	$	2.51	$	1.53	$	1.21	$	0.17	$	1.25
Cash dividends declared per common share	$	0.195	$	0.170	$	0.135	$	0.060	$	

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	Years Ended December 31, 2005	2004	2003	2002	2001
	($ in thousands, except per share data)				
Cash Flow Data:					
Cash provided by operating activities	$ 2,406,888	$ 1,432,274	$ 938,907	$ 428,797	$ 478,098
Cash used in investing activities	7,017,494	3,381,204	2,077,217	779,745	670,105
Cash provided by financing activities	4,663,737	1,915,245	931,254	480,991	310,146
Effect of exchange rate changes on cash					(545)
Balance Sheet Data (at end of period):					
Total assets	$ 16,118,462	$ 8,244,509	$ 4,572,291	$ 2,875,608	$ 2,286,768
Long-term debt, net of current maturities	5,489,742	3,075,109	2,057,713	1,651,198	1,329,453
Stockholders equity	6,174,323	3,162,883	1,732,810	907,875	767,407

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 gas sales, average sales prices received and expenses for the periods indicated:

	December 31, 2005	2004	2003
Net Production:			
Oil (mbbl)	7,698	6,764	4,665
Gas (mmcf)	422,389	322,009	240,366
Gas equivalent (mmcfe)	468,577	362,593	268,356
Oil and Gas Sales ($ in thousands):			
Oil sales	$ 401,845	$ 260,915	$ 132,630
Oil derivatives realized gains (losses)	(34,132)	(69,267)	(12,058)
Oil derivatives unrealized gains (losses)	4,374	3,454	(9,440)
Total oil sales	372,087	195,102	111,132
Gas sales	3,231,286	1,789,275	1,171,050
Gas derivatives realized gains (losses)	(367,551)	(85,634)	(5,331)
Gas derivatives unrealized gains (losses)	36,763	37,433	19,971
Total gas sales	2,900,498	1,741,074	1,185,690
Total oil and gas sales	$ 3,272,585	$ 1,936,176	$ 1,296,822
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 52.20	$ 38.57	$ 28.43
Gas ($ per mcf)	$ 7.65	$ 5.56	$ 4.87
Gas equivalent ($ per mcfe)	$ 7.75	$ 5.65	$ 4.86
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 47.77	$ 28.33	$ 25.85
Gas ($ per mcf)	$ 6.78	$ 5.29	$ 4.85
Gas equivalent ($ per mcfe)	$ 6.90	$ 5.23	$ 4.79
Expenses ($ per mcfe):			
Production expenses	$ 0.68	$ 0.56	$ 0.51
Production taxes (a)	$ 0.44	$ 0.29	$ 0.29
General and administrative expenses	$ 0.14	$ 0.10	$ 0.09
Oil and gas depreciation, depletion and amortization	$ 1.91	$ 1.61	$ 1.38
Depreciation and amortization of other assets	$ 0.11	$ 0.08	$ 0.06
Interest expense (b)	$ 0.47	$ 0.45	$ 0.55
Interest Expense ($ in thousands):			

Interest expense	$ 226,330	$ 162,781	$ 151,676
Interest rate derivatives realized (gains) losses	(4,945)	(791)	(3,859)
Interest rate derivatives unrealized (gains) losses	(1,585)	5,338	6,539
Total interest expense	$ 219,800	$ 167,328	$ 154,356
Net Wells Drilled	816	546	456
Net Producing Wells as of the End of Period	16,985	8,058	5,873

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(a) Production taxes in 2004 include a benefit of $6.8 million, or $0.02 per mcfe, from 2003 severance tax credits.
(b) Includes realized gains or (losses) from interest rate derivatives, but does not include unrealized gains or (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 subsidiary. 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 2005, 2004 and 2003 and our assets as of December 31, 2005, 2004 and 2003.

Executive Summary

Chesapeake is the second largest independent producer of natural gas in the United States and we own interests in approximately 30,600 producing oil and gas wells. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves primarily in the southwestern U.S. and secondarily in the Appalachian Basin in the eastern U.S. Our most important operating area has historically been the Mid-Continent region, which includes Oklahoma, Arkansas, Kansas and the Texas Panhandle. At December 31, 2005, 51% of our proved reserves were located in the Mid-Continent. During the past four years, we have also built significant positions in the South Texas and Texas Gulf Coast regions, the Permian Basin of West Texas and eastern New Mexico, the Barnett Shale area of north-central Texas, the Ark-La-Tex area of East Texas and northern Louisiana and the emerging Fayetteville Shale play in Arkansas. As a result of our recent acquisition of Columbia Energy Resources, LLC and its subsidiaries, including Columbia Natural Resources, LLC (CNR) as described below, we now have a significant presence in the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York.

Chesapeake attributes its strong organic growth rates during 2005 and in the past five years to management s early recognition that oil and 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 invested more than $3.0 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be the largest inventories of onshore leasehold (8.5 million net acres) and 3-D seismic (11.6 million acres) in the U.S. On this leasehold, the company has identified more than a 10-year drilling inventory of approximately 28,000 drilling locations.

In addition, Chesapeake has significantly strengthened its technical capabilities during the past five years by increasing its land, geoscience and engineering staff by 400% to over 600 employees. Today, the company has more than 3,300 employees, of which approximately 70% work in the company s E&P operations and 30% work in the company s oilfield service operations.

Oil and natural gas production for 2005 was 468.6 bcfe, an increase of 106.0 bcfe, or 29% over the 362.6 bcfe produced in 2004. We have increased our production for 16 consecutive years and 18 consecutive quarters. During these 18 quarters, Chesapeake s U.S. production has increased 262% for an average compound quarterly growth rate of 7% and an average compound annual growth rate of 33%.

In addition to increased oil and natural gas production, the prices we received were higher in 2005 than in 2004. On a natural gas equivalent basis, weighted average prices (excluding the effect of unrealized gains or losses on derivatives) were $6.90 per mcfe in 2005 compared to $5.23 per mcfe in 2004. The increase in prices resulted in an increase in revenue of $782.2 million, and increased production resulted in an increase in revenue of $554.0 million, for a total increase in revenue of $1.336 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 2005, Chesapeake drilled 902 (686 net) operated wells and participated in another 1,066 (130 net) wells operated by other companies. The company s drilling success rate was 98% for company-operated wells and 95% for non-operated wells. During 2005, Chesapeake invested $1.511 billion in operated wells (using an average of 73 operated rigs), $309 million in non-operated wells (using an average of approximately 66 non-operated rigs) and $362 million in acquiring new 3-D seismic data and new leasehold (excluding leasehold acquired through acquisitions). Our acquisition expenditures totaled $4.9 billion during 2005 (including amounts paid for unproved leasehold and excluding $252 million of deferred taxes in connection with certain corporate acquisitions). We expect to continue replacing reserves through the drillbit and acquisitions, although the timing and magnitude of future additions are uncertain.

Chesapeake began 2005 with estimated proved reserves of 4.902 tcfe and ended the year with 7.521 tcfe, an increase of 2.619 tcfe, or 53%. During 2005, we replaced 468.6 bcfe of production with an estimated 3.088 tcfe of new proved reserves, for a reserve replacement rate of 659%. This compares to reserve replacement of 578% and 459% for 2004 and 2003, respectively. Reserve replacement through the drillbit was 1.047 tcfe, or 223% of production (including a positive 17 bcfe from performance revisions and a positive 24 bcfe from oil and natural gas price increases), or 34% of the total increase. Reserve replacement through acquisitions was 2.041 tcfe, or 436% of production, or 66% of the total increase. Our annual decline rate on producing properties is projected to be 24% from 2006 to 2007, 16% from 2007 to 2008, 13% from 2008 to 2009, 11% from 2009 to 2010 and 10% from 2010 to 2011. Our percentage of proved undeveloped reserve additions to total proved reserve additions was approximately 36% in 2005, 56% in 2004 and 35% in 2003. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2005 will begin producing within the next five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within a year.

On November 14, 2005, we acquired CNR and its significant natural gas reserves, acreage and mid-stream assets for approximately $3.02 billion, of which $2.2 billion was in cash and $0.82 billion was in assumed liabilities related to CNR s working capital deficit and its prepaid sales agreement and hedging positions. The CNR assets consist of 125 mmcfe per day of natural gas production, 1.3 tcfe of proved reserves and approximately 3.2 million net acres of U.S. oil and gas leasehold, which we estimate have over 9,000 additional undrilled locations with reserve potential. CNR also owns extensive mid-stream natural gas assets, including over 6,500 miles of natural gas gathering lines.

In anticipation of today s tight drilling rig market, Chesapeake began making a series of investments in drilling rigs in 2001. In that year, Chesapeake formed its 100% owned drilling rig subsidiary, Nomac Drilling Corporation, with an investment of $26 million to build and refurbish five drilling rigs. Chesapeake has invested a total of $123 million in Nomac s 19 operating rigs, invested another $26 million in 25 rigs that Nomac is currently building, and budgeted an additional $191 million for completion of these rigs.

In addition to Nomac, Chesapeake has also made four other major drilling rig investments. The first of these was its ownership of approximately 17% of the common stock of Pioneer Drilling Company (Pioneer), which we began acquiring in 2003. The company recently sold its Pioneer stock, realizing proceeds of $159 million and a pre-tax gain of $116 million that it will recognize in the 2006 first quarter. Chesapeake re-invested the Pioneer proceeds to acquire 13 rigs from privately held Martex Drilling Company, L.L.P. for $150 million.

Chesapeake has invested $43 million in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake owns 45% and 49%, respectively. DHS owns ten drilling rigs and has three more rigs on order. Mountain owns one drilling rig and has ordered another nine rigs for delivery in 2006 and 2007. Chesapeake s drilling rig investments have served as a partial hedge to rising service costs and have also provided competitive advantages in making acquisitions and in developing its own leasehold on a more timely basis.

As of December 31, 2005, the company s debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 47% compared to 49% as of December 31, 2004. During 2005, we received net proceeds of $5.252 billion through issuances of $1.380 billion of preferred equity, $1.025 billion of common equity, and $2.990 billion principal amount of senior notes. We issued 18.7 million shares of common stock in exchange for outstanding shares of our 4.125% and 5.0% (Series 2003) preferred stock and upon conversions of our 6.0% preferred stock. Additionally, we purchased and retired $564.4 million principal amount of outstanding senior notes during 2005. As a result of our debt transactions during 2005, we have extended the average maturity of our long-term debt to over 10 years and have lowered our average interest rate to approximately 6.3%.

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 in the future.

Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. The Resignation Agreement provides for the immediate vesting of all of Mr. Ward s unvested stock options and restricted stock on February 10, 2006. As a result of such vesting, 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 became immediately vested. As a result, the company expects to incur a non-cash after-tax charge of approximately $31.8 million in the first quarter 2006.

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 cash flow from operations will exceed our drilling capital expenditures in 2006. Our budget for drilling, land and seismic activities during 2006 is currently between $3.0 billion and $3.2 billion. We believe this level of exploration and development will be sufficient to increase our reserves in 2006 and achieve our goal of a 10% to 20% increase in production over 2005 production (inclusive of acquisitions completed or scheduled to close in 2006 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2006). 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. Any cash flow from operations not needed to fund our drilling program will be available for acquisitions, dividends, debt repayment or other general corporate purposes in 2006.

Cash provided by operating activities was $2.407 billion in 2005, compared to $1.432 billion in 2004 and $938.9 million in 2003. The $975 million increase from 2004 to 2005 and the $493.1 million increase from 2003 to 2004 were primarily due to higher realized prices and higher volumes of oil and gas production. We expect that 2006 production volumes will be higher than in 2005 and that cash provided by operating activities in 2006 will exceed 2005 levels. While a precipitous decline in gas prices in 2006 would affect the amount of cash flow that would be generated from operations, we have 63% of our expected oil production in 2006 hedged at an average NYMEX price of $61.02 per barrel of oil and 71% (excluding the hedges assumed in the CNR acquisition and certain collars and options) of our expected natural gas production in 2006 hedged at an average NYMEX price of $9.43 per mcf. This level of hedging provides certainty of the cash flow we will receive for a substantial portion of our 2006 production. Depending on changes in oil and 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. At December 31, 2005 and March 10, 2006, we had $50 million of letters of credit securing our performance of hedging contracts. To mitigate the liquidity impact of those collateral requirements, we have negotiated caps on the amount of collateral that we might be required to post with seven of our counterparties. All of our existing commodity hedges that are not under our

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secured hedge facilities (described below under *Contractual Obligations*) are with these counterparties and the maximum amount of collateral that we would be required to post with them is no more than $230 million in the aggregate.

A significant source of liquidity is our $2.0 billion syndicated revolving bank credit facility which matures in February 2011. At March 10, 2006, there was $1.5 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 $5.682 billion and repaid $5.669 billion in 2005, we borrowed $2.160 billion and repaid $2.101 billion in 2004 and we borrowed and repaid $738 million in 2003 under our bank credit facility. We incurred $4.7 million, $2.2 million and $2.5 million of financing costs related to our revolving bank credit facility in 2005, 2004 and 2003, respectively, as a result of amendments to the credit facility agreement. Also during 2005, we repaid the remaining credit facility balance of $96.1 million assumed in the CNR acquisition.

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, interest 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 for 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 2005, 2004 and 2003 ($ in millions):

	2005		2004		2003	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Unsecured senior notes guaranteed by subsidiaries	$ 2,300.0	$ 2,251.3	$ 1,200.0	$ 1,166.0	$ 500.0	$ 485.4
Contingent convertible unsecured senior notes	690.0	673.3				
Convertible preferred stock	1,380.0	1,341.5	313.3	304.9	402.5	390.4
Common stock	1,024.6	985.8	650.0	624.2	186.3	177.4
Total	$ 5,394.6	$ 5,251.9	$ 2,163.3	$ 2,095.1	$ 1,088.8	$ 1,053.2

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 $60.5 million, $38.9 million and $27.3 million in 2005, 2004 and 2003, respectively, and we paid dividends on our preferred stock of $31.5 million, $40.9 million and $20.9 million in 2005, 2004 and 2003, respectively. We received $21.6 million, $12.0 million and $9.3 million from the exercise of employee and director stock options and warrants in 2005, 2004 and 2003, respectively. We paid $4.0 million and $2.1 million to purchase treasury stock in 2005 and 2003 to fund our matching contributions to our 401(k) make-up plan. There were no treasury stock purchases made in 2004.

In 2005, we paid $11.6 million to settle derivative liabilities assumed from CNR.

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Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased by $61.2 million, $88.3 million and $28.3 million in 2005, 2004 and 2003, 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. The following table shows our redemption, purchases and exchanges of senior notes for 2005, 2004 and 2003 ($ 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
For the Year Ended December 31, 2003:					
8.5% Senior Notes due 2012	$ 106.4	$ 6.7	$	$	$ 113.1
8.5% Senior Notes due 2012 (c)	32.0		1.5	(33.5)	
8.375% Senior Notes due 2008 (d)	27.9		1.6	(29.5)	
8.375 Senior Notes due 2008 and 8.125% Senior Notes due 2011 (e)	22.9		0.8	(23.7)	
8.375% Senior Notes due 2008 and 8.125% Senior Notes due 2011 (f)	61.2		2.6	(63.8)	
	$ 250.4	$ 6.7	$ 6.5	$ (150.5)	$ 113.1

(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.
(c) We issued $33.5 million of our 7.75% Senior Notes.
(d) We issued $29.5 million of our 7.75% Senior Notes.
(e) We issued $23.7 million of our 7.75% Senior Notes for $6.0 million 8.375% Senior Notes and $16.8 million 8.125% Senior Notes.
(f) We issued $63.8 million of our 7.5% Senior Notes for $6.3 million 8.375% Senior Notes and $54.9 million 8.125% Senior Notes.

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Cash used in investing activities increased to $6.921 billion in 2005, compared to $3.381 billion in 2004 and $2.077 billion in 2003. The following table shows our capital expenditures during these years ($ in millions):

	2005	2004	2003
Acquisitions of oil and gas companies, proved and unproved properties, net of cash acquired	$ 3,925.5	$ 1,914.7	$ 1,261.3
Exploration and development of oil and gas properties	2,371.9	1,276.3	727.2
Additions to buildings and other fixed assets	417.5	126.7	71.5
Additions to investments	135.0	37.0	30.8
Additions to drilling equipment	66.8	23.1	1.2
Deposits for acquisitions	35.0	16.3	13.3
Total	$ 6,951.7	$ 3,394.1	$ 2,105.3

Through divestitures of oil and gas properties, we received $9.8 million in 2005, $12.0 million in 2004 and $22.2 million, in 2003. Sales of other assets and investments in securities of other companies provided $20.4 million, $0.9 million and $5.8 million of cash in 2005, 2004 and 2003, respectively.

Our accounts receivable are primarily from purchasers of oil and natural gas ($615.4 million at December 31, 2005) and exploration and production companies which own interests in properties we operate ($84.8 million at December 31, 2005). 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.

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

Investing and Financing Transactions

The following table describes investing transactions that we completed in 2005 ($ in millions):

Acquisition	Location	Amount
Columbia Natural Resources, LLC	Appalachian Basin	$ 2,200(a)
BRG Petroleum Corporation	Mid-Continent and Ark-La-Tex	325(b)
Hallwood Energy, III L.P.	Barnett Shale	250(c)
Laredo Energy II, L.L.C.	South Texas	228
Houston-based oil and gas company	Texas Gulf Coast/South Texas	202
Pecos Production Company	Permian	198
Laredo II Partners	Texas Gulf Coast/South Texas	139
Corpus Christi-based oil and gas company	Ark-La-Tex	95
Dallas-based oil and gas company	Ark-La-Tex	85
Midland-based oil and gas company	Permian	38
Other	Various	372(d)
		$ 4,132

(a) Includes $175 million related to gathering systems which was allocated to other property and equipment.
(b) We paid $16.3 million of the purchase amount in 2004.
(c) Includes $15 million related to gathering systems which was allocated to other property and equipment.

(d) In 2005, we paid the remaining $57 million of the purchase price related to an acquisition transaction with Hallwood Energy Corporation in the fourth quarter of 2004.

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During 2004 and continuing in 2005, we have taken several steps to improve our capital structure. These transactions enabled us to extend our average maturity of long-term debt to over ten years with an average interest rate of approximately 6.3%. 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 2005:

First Quarter 2005

- Amended our revolving bank credit facility to increase the committed borrowing base to $1.25 billion and extended the maturity of the facility to January 2010.

- Completed a private purchase of $11.0 million of our 8.375% Senior Notes due 2008 for $12.0 million (including a premium of $0.8 million).

Second Quarter 2005

- Completed private offerings of $600 million principal amount of 6.625% Senior Notes due 2016 and 4,600,000 shares of 5.0% cumulative convertible preferred stock having a liquidation preference of $100 per share. Net proceeds of approximately $1.032 billion from these transactions were used to finance acquisitions totaling $459 million that closed in the second quarter of 2005 and to repay debt incurred under our revolving bank credit facility to temporarily finance the BRG and the Laredo acquisitions completed in the first quarter.

- Completed a private placement of $600 million of 6.25% Senior Notes due 2018. Net proceeds of approximately $596.4 million were used to fund our purchases in June 2005 of $237.8 million of our 8.125% Senior Notes due 2011 for $255.3 million (including a premium of $16.8 million and transaction costs of $0.7 million) and $298.9 million of our 9.0% Senior Notes due 2012 for $341.0 million (including a premium of $41.3 million and transaction costs of $0.8 million) pursuant to tender offers for the 8.125% and 9.0% Senior Notes.

- Completed a private exchange of 45,000 shares of our outstanding 4.125% cumulative convertible preferred stock for 2,911,250 shares of common stock. No cash was received or paid in connection with this transaction.

Third Quarter 2005

- Completed cash tender offers for our 8.125% Senior Notes due 2011 and 9.0% Senior Notes due 2012. Approximately $0.3 million was used to purchase $0.1 million of 8.125% Senior Notes due 2011 and $0.2 million of 9.0% Senior Notes due 2012. Together with the amounts acquired in June 2005, we acquired a total of $237.9 million principal amount of 8.125% Senior Notes due 2011 and $299.1 million principal amount of 9.0% Senior Notes due 2012, representing 96.9% and 99.7%, respectively, of the amounts outstanding, in the tender offers, which expired on July 6, 2005. We redeemed the remaining $7.5 million of 8.125% and $0.9 million of 9.0% Senior Notes for $9.1 million (including a premium of $0.6 million) on August 17, 2005 based on the make-whole redemption provisions in the indentures.

- Completed a number of transactions whereby we exchanged 133,675 shares of our 4.125% cumulative convertible preferred stock for 8,529,758 shares of our common stock. No cash was received or paid in connection with these transactions.

Completed a number of transactions whereby we exchanged 697,724 shares of our 5.0% (Series 2003) cumulative convertible preferred stock for 4,354,439 shares of our common stock. No cash was received or paid in connection with these transactions.

Completed a private placement of $600 million of 6.5% Senior Notes due 2017. Net proceeds of approximately $584.6 million were used to repay amounts outstanding under our revolving bank credit facility which resulted from acquisitions completed in the third quarter.

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Completed public offerings of 3,450,000 shares of 4.5% cumulative convertible preferred stock having a liquidation preference of $100 per share and 9,200,000 shares of common stock at $32.72 per share. Net proceeds from both offerings of approximately $624.6 million were used to repay amounts outstanding under our revolving bank credit facility which resulted from acquisitions completed in the third quarter.

Fourth Quarter 2005

Completed private offerings of $500 million of 6.875% Senior Notes due 2020, $690 million of 2.75% Contingent Convertible Senior Notes due 2035 and 5,750,000 shares of 5.00% cumulative convertible preferred stock having a liquidation preference of $100 per share. Net proceeds of approximately $1.718 billion along with cash on hand and borrowings under our credit facility were used to fund the CNR acquisition.

Completed a public offering of 23 million shares of common stock at $31.46 per share. Net proceeds of approximately $696.4 million were used to repay outstanding borrowings under our revolving bank credit facility which were incurred to temporarily finance the CNR acquisition.

Completed a number of transactions whereby we exchanged 45,515 shares of our 4.125% cumulative convertible preferred stock for 2,880,873 shares of our common stock. No cash was received or paid in connection with these transactions.

Completed an exchange of 1,330 shares of 5.0% (Series 2003) cumulative convertible preferred stock for 8,281 shares of common stock. No cash was received or paid in connection with these transactions.

Contractual Obligations

We currently have a $2.0 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. As of December 31, 2005, we had $72.0 million of outstanding borrowings under this facility and had utilized $53.0 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% 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 an annual commitment fee that also varies from 0.125% to 0.30% according to our senior unsecured long-term debt ratings. Currently the annual commitment fee is 0.25%. 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, purchase or redeem our capital stock, 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. At December 31, 2005, our indebtedness to total capitalization ratio was 0.48 to 1 and our indebtedness to EBITDA ratio was 2.34 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($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.

Some of our commodity price and financial risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations exceed certain levels. As of December 31, 2005, we were required to post $50 million of collateral in the form of

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letters of credit with respect to such derivative transactions. These collateral requirements were $50 million as of March 10, 2005. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and fluctuations in natural gas and oil prices and interest rates. We currently have arrangements with five of our counterparties, with which we have outstanding transactions, that limit the amount of collateral that we would be required to post with them to no more than $230 million in the aggregate.

We have two secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to $500 million. The scheduled maturity date for these facilities is May 2010. 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. One of the hedging facilities is subject to an annual fee of 0.30% of the maximum total capacity and each of them has a 1.0% exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of December 31, 2005, the fair market value of the natural gas and oil hedging transactions was a liability of $92.9 million under one of the facilities and a liability of $10.9 million under the other facility. As of March 10, 2006, the fair market value of the same transactions was an asset of approximately $100 million and $400 million, respectively. 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 gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time.

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 domestic subsidiaries. Our revolving bank credit facility and secured hedge 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 hedge 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, 2005, senior notes represented approximately $5.4 billion of our long-term debt and consisted of the following ($ in thousands):

7.5% Senior Notes due 2013	$ 363,823
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	600,000
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	(95,577)
Discount for interest rate derivatives	(11,349)
	$ 5,417,742

No scheduled principal payments are required on any of the senior notes until 2013, when $363.8 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 the notes.

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As of December 31, 2005 and currently, debt ratings for the senior notes are Ba2 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (stable outlook) and BB by Fitch Ratings (stable outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. All of our wholly-owned domestic subsidiaries guarantee the notes. The indentures (other than the indentures issued after June 2005) contain covenants limiting our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; engage in transactions with affiliates; sell assets; 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, 2005, we estimate that secured commercial bank indebtedness of approximately $3.6 billion could have been incurred under the most restrictive indenture covenant.

The table below summarizes our contractual obligations as of December 31, 2005 ($ in thousands)

		Payments Due By Period			
		Less than	1-3	3-5	More than
Contractual Obligations	**Total**	**1 Year**	**Years**	**Years**	**5 years**
Long-term debt obligations	$ 5,596,668	$	$	$	$ 5,596,668
Capital lease obligations	8,979	3,370	4,219	1,390	
Operating lease obligations	13,759	4,124	6,310	2,623	702
Purchase obligations (a)	662,551	387,290	167,375	12,419	95,467
Standby letters of credit	57,609	57,609			
Other long-term obligations					
Total contractual cash obligations	$ 6,339,566	$ 452,393	$ 177,904	$ 16,432	$ 5,692,837

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

Hedging Activities

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. 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, 2005, our oil and 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 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 activity is dynamic.

Mark-to-market positions under oil and 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.

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Realized gains and losses from our oil and gas derivatives resulted in a net decrease in oil and gas sales of $401.7 million, or $0.86, per mcfe in 2005, a net decrease of $154.9 million, or $0.43, per mcfe in 2004 and a net decrease of $17.4 million, or $0.06, per mcfe in 2003. Oil and gas sales also include changes in the fair value of oil and 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 gas sales in 2005, 2004 and 2003 were $41.1 million, $40.9 million and $10.5 million, respectively. Included in these unrealized gains (losses) are gains (losses) on ineffectiveness of cash flow hedges of ($76.3) million in 2005, ($8.2) million in 2004 and ($9.2) million in 2003.

Changes in the fair value of oil and 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 until being transferred to earnings in the month of related production. These unrealized losses, net of related tax effects, totaled $270.7 million, $4.4 million and $20.3 million as of December 31, 2005, 2004, and 2003, respectively. Based upon the market prices at December 31, 2005, we expect to transfer to earnings approximately $153.8 million of the loss included in the balance of accumulated other comprehensive income during the next 12 months when the transactions actually occur. A detailed explanation of accounting for oil and gas derivatives under SFAS 133 appears under Application of Critical Accounting Policies Hedging elsewhere in this Item 7.

The fair values of our oil and gas derivative instruments are recorded on our consolidated balance sheet as assets or liabilities. The estimated fair values of our oil and gas derivative instruments (including derivatives acquired from CNR) as of December 31, 2005 and 2004 are provided below:

	December 31,	
	2005	**2004**
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price gas swaps	$ (1,047,094)	$ 57,073
Gas basis protection swaps	307,308	122,287
Fixed-price gas cap-swaps	(161,056)	(48,761)
Fixed-price gas counter-swaps	37,785	4,654
Gas call options (a)	(21,461)	(5,793)
Fixed-price gas collars	(9,374)	(5,573)
Fixed-price gas locked swaps	(34,229)	(77,299)
Floating-price gas swaps	2,607	
Fixed-price oil swaps	(16,936)	
Fixed-price oil cap-swaps	(3,364)	(8,238)
Estimated fair value	$ (945,814)	$ 38,350

(a) After adjusting for the remaining $23.0 million and $3.2 million premium paid to Chesapeake by the counterparty, the cumulative unrealized loss related to these call options as of December 31, 2005 and 2004 was $1.6 million and $2.6 million, respectively.

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

	December 31, 2005	2004	2003
	($ in thousands)		
Fair value of contracts outstanding, as of January 1	$ 38,350	$ (44,988)	$ (14,533)
Change in fair value of contracts during the period	(771,076)	(69,927)	(31,078)
Contracts realized or otherwise settled during the period	401,684	154,901	17,389
Fair value of new contracts when entered into during the period	(614,772)	(5,369)	(16,766)
Fair value of contracts when closed during the period		3,733	
Fair value of contracts outstanding, as of December 31	$ (945,814)	$ 38,350	$ (44,988)

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 of interest rate derivatives 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. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

As of December 31, 2005, the following interest rate swaps were 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 Gain (Loss) ($ in thousands)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,734)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	$ (5,133)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	$ (5,327)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	$ (5,004)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	$ (1,344)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	$ (3,240)
October 2005 January 2016	$ 200,000,000	6.625%	6 month LIBOR plus 129 basis points	$ 282

In January 2006, we closed the interest rate swap on our 6.625% Senior Notes for $1.0 million. Subsequent to December 31, 2005, 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 2006 January 2016	$ 250,000,000	6.625%	6 month LIBOR plus 129 basis points
March 2006 January 2016	$ 250,000,000	6.875%	6 month LIBOR plus 120 basis points
March 2006 August 2017	$ 250,000,000	6.500%	6 month LIBOR plus 125.5 basis points

In 2005, we closed various interest rate swaps for gains totaling $7.1 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.

In March 2004, Chesapeake entered into an interest rate swap which required Chesapeake to pay a fixed rate of 8.68% while the counterparty paid Chesapeake a floating rate of six month LIBOR plus 0.75% on a notional amount of $142.7 million. On March 15, 2005, we elected to terminate the interest rate swap and paid $31.8 million to the counterparty.

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Results of Operations

General. For the year ended December 31, 2005, Chesapeake had net income of $948.3 million, or $2.51 per diluted common share, on total revenues of $4.665 billion. This compares to 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, and net income of $313.0 million, or $1.21 per diluted common share, on total revenues of $1.717 billion during the year ended December 31, 2003. The 2005 net income includes, on a pre-tax basis, a $70.4 million loss on repurchased debt and $42.7 million in net unrealized gains on oil and gas and interest rate derivatives. The 2004 net income includes, on a pre-tax basis, a $24.6 million loss on repurchased debt, a $4.5 million provision for legal settlements and $35.5 million in net unrealized gains on oil and gas and interest rate derivatives. The 2003 net income includes, on a pre-tax basis, a $20.8 million loss on repurchased debt, a $6.4 million provision for legal settlements, $4.0 million in net unrealized losses on oil and gas and interest rate derivatives, and a $2.0 million impairment of our investment in Seven Seas Petroleum Inc.

Oil and Gas Sales. During 2005, oil and gas sales were $3.273 billion compared to $1.936 billion in 2004 and $1.297 billion in 2003. In 2005, Chesapeake produced and sold 468.6 bcfe at a weighted average price of $6.90 per mcfe, compared to 362.6 bcfe in 2004 at a weighted average price of $5.23 per mcfe, and 268.4 bcfe in 2003 at a weighted average price of $4.79 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of $41.1 million, $40.9 million and $10.5 million in 2005, 2004 and 2003, respectively). The increase in prices in 2005 resulted in an increase in revenue of $782 million and increased production resulted in a $554 million increase, for a total increase in revenues of $1.336 billion (excluding unrealized gains or losses on oil and 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 2005, we realized an average price per barrel of oil of $47.77, compared to $28.33 in 2004 and $25.85 in 2003 (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 $6.78, $5.29 and $4.85 in 2005, 2004 and 2003, respectively. Realized gains or losses from our oil and gas derivatives resulted in a net decrease in oil and gas revenues of $401.7 million or $0.86 per mcfe in 2005, a net decrease of $154.9 million or $0.43 per mcfe in 2004 and a net decrease of $17.4 million or $0.06 per mcfe in 2003.

A change in oil and gas prices has a significant impact on our oil and gas revenues and cash flows. Assuming 2005 production levels, a change of $0.10 per mcf of gas sold would result in an increase or decrease in revenues and cash flow of approximately $42.2 million and $39.5 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 $7.7 million and $7.2 million, respectively, without considering the effect of hedging activities.

The following table shows our production by region for 2005, 2004 and 2003:

	Years Ended December 31,					
	2005		2004		2003	
	Mmcfe	Percent	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	297,773	64%	268,459	74%	233,559	87%
South Texas and Texas Gulf Coast	63,852	13	42,427	12	15,546	6
Ark-La-Tex and Barnett Shale	58,116	12	19,640	5	7,776	3
Permian	40,207	9	29,468	8	8,496	3
Appalachia	5,878	1				
Other	2,751	1	2,599	1	2,979	1
Total Production	468,577	100%	362,593	100%	268,356	100%

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Natural gas production represented approximately 90% of our total production volume on an equivalent basis in 2005, compared to 89% in 2004 and 90% in 2003.

Oil and Gas Marketing Sales. Chesapeake realized $1.393 billion in oil and gas marketing sales to third parties in 2005, with corresponding oil and gas marketing expenses of $1.358 billion, for a net margin of $35 million. Marketing activities are substantially for third parties who are owners in Chesapeake operated wells. This compares to sales of $773 million and $421 million, expenses of $755 million and $410 million, and margins of $18 million and $11 million in 2004 and 2003, respectively. In 2005 and 2004, Chesapeake realized an increase in volumes and prices related to oil and gas marketing sales as compared to the previous year.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $317.0 million in 2005, compared to $204.8 million and $137.6 million in 2004 and 2003, respectively. On a unit-of-production basis, production expenses were $0.68 per mcfe in 2005 compared to $0.56 and $0.51 per mcfe in 2004 and 2003, respectively. The increase in 2005 was primarily due to higher third-party field service costs, energy costs and personnel costs. We expect that production expenses per mcfe produced for 2006 will range from $0.77 to $0.82.

Production Taxes. Production taxes were $207.9 million in 2005 compared to $103.9 million in 2004 and $77.9 million in 2003. On a unit-of-production basis, production taxes were $0.44 per mcfe in 2005 compared to $0.29 per mcfe in both 2004 and 2003. The $104.0 million increase in production taxes in 2005 is due primarily to approximately 106.0 bcfe of increased production and the increase of $2.10 per mcfe in sales price (excluding gains or losses on derivatives). 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 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 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 gas prices are higher. We expect production taxes per mcfe to range from $0.41 to $0.46 during 2006 based on NYMEX prices of $54.00 per barrel of oil and natural gas wellhead prices ranging from $7.50 to $8.50 per mcfe produced.

General and Administrative Expense. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and gas properties (see Note 11 of notes to consolidated financial statements), were $64.3 million in 2005, $37.0 million in 2004 and $23.8 million in 2003. General and administrative expenses were $0.14, $0.10 and $0.09 per mcfe for 2005, 2004 and 2003, respectively. The increase in 2005 and 2004 was the result of the company s overall growth. This growth has resulted in a substantial increase in employees and related costs. Included in general and administrative expenses is stock-based compensation of $15.3 million in 2005, $4.8 million in 2004 and $0.9 million in 2003. During 2005, 3.9 million shares of restricted stock, net of forfeitures, were granted to employees. The cost of all outstanding restricted shares is amortized over a four-year period which resulted in the recognition of $23.3 million of stock-based compensation costs during 2005. Of this amount, $12.6 million was reflected in general and administrative expense, and the remaining $10.7 million was capitalized to oil and gas properties. Chesapeake did not issue restricted stock awards prior to 2004. Additionally, we recognized $3.9 million, $0.6 million and $0.9 million in stock-based compensation expense in 2005, 2004 and 2003, respectively, as a result of modifications made to previously issued stock options. Of the $3.9 million recognized in 2005, $1.2 million was capitalized to oil and gas properties. Stock-based compensation was $0.03 per mcfe for 2005 and $0.01 per mcfe for 2004. We anticipate that general and administrative expenses for 2006 will be between $0.22 and $0.26 per mcfe produced including stock based compensation ranging from $0.08 and $0.10 per mcfe produced.

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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 $102.2 million, $51.7 million and $35.5 million of internal costs (excluding stock-based compensation) in 2005, 2004 and 2003, respectively, directly related to our oil and gas property acquisition, exploration and development efforts.

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. In 2003, we recorded a $6.4 million provision related to the settlement of a class-action lawsuit with certain Oklahoma royalty owners.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties was $894.0 million, $582.1 million and $369.5 million during 2005, 2004 and 2003, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $1.91, $1.61 and $1.38 in 2005, 2004 and 2003, respectively. The increase in the average rate from $1.61 in 2004 to $1.91 in 2005 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 2006 DD&A rate to be between $2.15 and $2.20 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $51.0 million in 2005, compared to $29.2 million in 2004 and $16.8 million in 2003. The increase in 2005 and 2004 was primarily the result of higher depreciation costs resulting from the acquisition of various gathering facilities, compression equipment, 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 2005 and 2004. 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 drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and gas properties as exploration or development costs. We expect 2006 depreciation and amortization of other assets to be between $0.14 and $0.16 per mcfe produced.

Interest and Other Income. Interest and other income was $10.5 million, $4.5 million and $2.8 million in 2005, 2004 and 2003, respectively. 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. The 2003 income consisted of $1.0 million of interest income, a $0.4 million loss related to an equity investment, a $0.6 million gain on the final settlement of the sale of our Canadian subsidiary and $1.6 million of miscellaneous income.

Interest Expense. Interest expense increased to $219.8 million in 2005 compared to $167.3 million in 2004 and $154.4 million in 2003 as follows:

	Years Ended December 31,		
	2005	2004	2003
		($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 299.6	$ 194.5	$ 163.2
Capitalized interest	(79.0)	(36.2)	(13.0)
Amortization of loan discount	5.7	4.5	1.6
Unrealized (gain) loss on interest rate derivatives	(1.6)	5.3	6.5
Realized gain on interest rate derivatives	(4.9)	(0.8)	(3.9)
Total interest expense	$ 219.8	$ 167.3	$ 154.4
Average long-term borrowings	$ 3,948	$ 2,428	$ 1,932

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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 of interest rate derivatives 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. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense. A detailed explanation of our interest rate derivative activity appears below in Item 7A Quantitative and Qualitative Disclosures About Market Risk.

Interest expense, excluding unrealized (gains) losses on derivatives and net of amounts capitalized, was $0.47 per mcfe in 2005 compared to $0.45 per mcfe in 2004 and $0.55 per mcfe in 2003. We expect interest expense for 2006 to be between $0.52 and $0.57 per mcfe produced (before considering the effect of interest rate derivatives).

Loss on Investment in Seven Seas. In 2003, we reduced the carrying value of our 2001 investment in securities of Seven Seas Petroleum Inc. to zero by recording an impairment of $2.0 million. We recovered approximately $5.5 million on this investment in 2003 and recorded an impairment of $17.2 million in 2002.

Loss on Repurchases or Exchanges of Debt. During the past three years we have repurchased or exchanged Chesapeake debt and incurred losses in connection with these transactions. We entered into these transactions in order to re-finance a portion of our long-term debt at a lower rate of interest. The following table shows the losses related to these transactions for 2005, 2004 and 2003, respectively ($ in millions):

	Notes	Loss on Repurchases/Exchanges		
For the Year Ended December 31, 2005:	**Retired**	**Premium**	**Other (a)**	**Total**
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
For the Year Ended December 31, 2003:				
8.5% Senior Notes due 2012	$ 106.4	$ 6.7	$ 14.1(b)	$ 20.8

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

(b) Includes a $12.0 million loss that was recognized based on the hedging relationship between the notes and an associated interest rate derivative.

Income Tax Expense. Chesapeake recorded income tax expense of $545.1 million in 2005 compared to income tax expense of $289.8 million in 2004 and $191.8 million in 2003. Our effective income tax rate was 36.5% in 2005 compared to 36% in 2004 and 38% in 2003. The increase in 2005 reflected the impact state income taxes and permanent differences had on our overall effective rate. Our effective income tax rate will increase to 38% in 2006 to reflect our current assessment of expected increases in state income taxes and permanent differences. During 2003 and 2001, we determined that it was more likely than not that $4.4 million and $2.4 million, respectively, of the deferred tax assets related to Louisiana net operating losses would not be realized and we recorded a valuation allowance equal to such amounts during those years. In 2004, we acquired Louisiana oil and gas properties which resulted in us determining that it was more likely than not that the

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$6.8 million of deferred tax assets related to Louisiana net operating losses would be realized. Therefore, the $6.8 million valuation allowance was reversed at December 31, 2004 as part of the recording of the purchase of these assets. All 2005 income tax expense was deferred, and we expect most, if not all, of our 2006 income tax expense to be deferred.

Cumulative Effect of Accounting Change. Effective January 1, 2003, Chesapeake adopted SFAS No. 143, *Accounting For Asset Retirement Obligation*. Upon adoption of SFAS 143 in 2003, we recorded the discounted fair value of our expected future obligations of $30.5 million, a cumulative effect of the change in accounting principle, as an increase to earnings of $2.4 million (net of income taxes) and an increase in net oil and gas properties of $34.3 million.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $26.9 million in 2005 compared to $36.7 million in 2004. The 2005 loss was the result of private exchanges of $224.2 million of our 4.125% cumulative convertible preferred stock for 14.3 million shares of common stock and private exchanges of $69.9 million of our 5.0% (Series 2003) cumulative convertible preferred stock for 4.4 million shares of common stock. The 2004 loss was the result of a private exchange of $30.0 million of our 6.0% cumulative convertible preferred stock for 3.2 million shares of common stock and a public exchange of $194.8 million of our 6.0% cumulative convertible preferred stock for 20.8 million shares of common stock. 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. We also incurred $1.2 million in transaction costs related to the public exchange.

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 and interest rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of oil and gas derivative transactions are reflected in oil and gas sales, and results of interest rate hedging transactions are reflected in interest expense. The changes in the fair value of derivative instruments not qualifying for designation as 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 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 gas sales. For derivative instruments designated as fair value hedges (in accordance with SFAS 133),

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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 the inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Due to the volatility of oil and natural gas prices and, to a lesser extent, interest rates, the company s financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2005, 2004 and 2003, the net market value of our derivatives was a liability of $968.3 million, an asset of $2.5 million and a liability of $75.4 million, respectively. The derivatives that we acquired in our CNR acquisition represented $661.4 million of the liability at December 31, 2005. With respect to our derivatives held as of December 31, 2005, 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 $136 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 $8 million.

Oil and Gas Properties. The accounting for our business is subject to special accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and 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 gas properties are generally calculated on a well by well or lease or field basis versus the aggregated full cost pool basis. Additionally, gain or loss is generally recognized on all sales of oil and gas properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher oil and gas depreciation, depletion and amortization rate, and we will not have exploration expenses that successful efforts companies frequently have.

Capitalized costs are amortized on a composite unit-of-production method based on proved oil and 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 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. The two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues.

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

As of December 31, 2005, approximately 78% 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 2005 year-end reserve evaluation is included under Oil and 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.

The volatility of oil and natural gas prices and the impact of revisions to reserve estimates can have a significant impact on the company s financial condition and results of operations. Our oil and gas depreciation, depletion and amortization rates have increased from $1.38 per mcfe in 2003 to $1.91 per mcfe in 2005 reflecting the impact of increases in prices and finding costs during these periods. As of December 31, 2005, a decrease in natural gas prices of $0.10 per mcf and a decrease in oil prices of $1.00 per barrel would reduce the company s estimated proved reserves by 3.5 bcfe and by 1.1 bcfe, respectively, as a result of economic truncation of the expected producing lives of some properties.

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

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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, 2005, we had deferred tax assets of $726.5 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 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 business combinations, 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, 2005, we had accrued accounts receivable from our two co-founders, CEO Aubrey K. McClendon and former COO, Tom L. Ward, of $6.4 million and $6.4 million, respectively, representing joint interest billings from December 2005 which were invoiced and paid in January 2006. Since Chesapeake was founded in 1989, Messrs. McClendon and Ward have acquired small working interests in certain of our oil and gas properties by participating in our drilling activities. Joint interest billings to them 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, Messrs. McClendon and Ward may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake, but they are 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 30 days prior to the start of each calendar year. Their participation is permitted only under the terms outlined in the Founder Well Participation Program, which, among other things, limits their individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake s working interest would be reduced below 12.5% as a result of their participation. In addition, the company is reimbursed for the cost of its leasehold acquired by Messrs. McClendon and Ward as a result of their well participation. As a result of the resignation of Mr. Ward on February 10, 2006, his participation in the Founder Well Participation Program will expire on August 10, 2006, which is also the expiration date of non-competition covenants applicable to Mr. Ward.

As disclosed in Note 8 of the notes to our consolidated financial statements in Item 8, in 2005, Chesapeake had revenues of $851.4 million from oil and gas sales to Eagle Energy Partners I, L.P., an affiliated entity.

During 2005, 2004 and 2003, we paid legal fees of $1.2 million, $1.1 million and $2.1 million, respectively, for legal services provided by a law firm of which a former director is a member.

Recently Issued Accounting Standards

The Financial Accounting Standards Board 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 Financial Accounting Standards Board (FASB) issued SFAS No. 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. This statement is effective as of the beginning of the annual reporting period that begins after June 15, 2005. Since the issuance of SFAS 123(R), three FASB Staff Positions (FSPs) have been issued regarding SFAS 123(R). These FSPs, FSP FAS 123(R)-1 *Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under FASB Statement No. 123(R)*, FSP FAS 123(R)-2 *Practical Accommodation to the Application of Grant Date as Defined in FASB Statement No. 123(R),* and FSP FAS 123(R)-3 *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards* will be applicable upon the initial adoption of SFAS 123(R).

Chesapeake will implement SFAS 123(R) in the first quarter of 2006 and the Black-Scholes option pricing model will be used to value the stock options as of the grant date. Based on the stock options outstanding and unvested at December 31, 2005 and our current intention to limit future awards of stock options, we do not believe the new accounting requirement will have a significant impact on future results of operations.

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In March 2005, the FASB issued FASB Interpretation No. (FIN) 47, *Accounting for Conditional Asset Retirement Obligations*. FIN 47 specifies the accounting treatment for conditional asset retirement obligations under the provisions of SFAS No. 143. FIN 47 is effective no later than the end of the fiscal year ending after December 15, 2005. We adopted this statement effective December 31, 2005. Implementation of FIN 47 did not have a material effect on our financial statements.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3.* SFAS 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes made in fiscal years beginning after December 15, 2005. The impact of SFAS 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but we do not currently expect SFAS 154 to have a material impact on our financial statements.

In June 2005, the EITF reached a consensus on Issue No. 04-10, *Determining Whether to Aggregate Operating Segments That Do Not Meet the Quantitative Thresholds*. EITF Issue 04-10 confirmed that operating segments that do not meet the quantitative thresholds can be aggregated only if aggregation is consistent with the objective and basic principles of SFAS 131, *Disclosure about Segments of an Enterprise and Related Information*. The consensus in this issue should be applied for fiscal years ending after September 30, 2005, and the corresponding information for earlier periods, including interim periods, should be restated unless it is impractical to do so. The adoption of EITF Issue 04-10 is not expected to have a material impact on our disclosures.

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 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. The adoption of EITF Issue 04-13 is not expected to have a material impact on our financial statements.

Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and gas reserve estimates, planned capital expenditures, the drilling of oil and gas wells and future acquisitions, expected oil and gas production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations 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 Items 1. and 2. of this report and include:

- the volatility of oil and 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 gas reserves and projecting future rates of production and the timing of development expenditures,
- uncertainties in evaluating oil and gas reserves of acquired properties and associated potential liabilities,
- inability to effectively integrate and operate acquired companies and properties,
- unsuccessful exploration and development drilling,
- declines in the value of our oil and gas properties resulting in ceiling test write-downs,
- lower prices realized on oil and gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities,
- lower oil and gas prices could negatively affect our ability to borrow, and
- drilling and operating risks.

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 Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2005, our oil and 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 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 gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

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, then 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.

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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. 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 gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and 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 the counter-swaps are recorded as adjustments to oil and gas sales.

Chesapeake enters into derivatives from time to time for the purpose of converting a fixed price gas sales contract to a floating price. We refer to these contracts as floating price swaps. For a floating price swap, Chesapeake receives a floating market price from the counterparty and pays a fixed price.

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.

Chesapeake enters into basis protection swaps for the purpose of locking-in a price differential for oil or gas from a specified delivery point. We currently have basis protection swaps covering four different delivery points which correspond to the actual prices we receive for much of our gas production. By entering into these basis protection swaps, we have effectively reduced our exposure to market changes in future gas price differentials. As of December 31, 2005, the fair value of our basis protection swaps was $307.3 million. Currently, our basis protection swaps cover approximately 24% of our anticipated gas production remaining in 2006, 24% in 2007, 20% in 2008, and 14% in 2009.

Gains or losses from derivative transactions are reflected as adjustments to oil and gas sales on the consolidated statements of operations. Realized gains (losses) included in oil and gas sales were ($401.7) million, ($154.9) million and ($17.4) million in 2005, 2004 and 2003, 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 gas sales. Unrealized gains (losses) included in oil and gas sales were $41.1 million, $40.9 million and $10.5 million, in 2005, 2004 and 2003, 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 gas sales as unrealized gains (losses). We recorded a gain (loss) on ineffectiveness of ($76.3) million, ($8.2) million and ($9.2) million in 2005, 2004 and 2003, respectively.

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As of December 31, 2005, we had the following open oil and gas derivative instruments designed to hedge a portion of our oil and gas production for periods after December 2005 (excluding derivatives acquired from CNR):

	Volume	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, 2005 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
1Q 2006	93,030,000	10.60				Yes		(34,043)
2Q 2006	61,880,000	9.03				Yes		(80,285)
3Q 2006	62,560,000	9.02				Yes		(87,205)
4Q 2006	52,155,000	9.42				Yes		(80,961)
1Q 2007	37,800,000	10.72				Yes		(40,253)
2Q 2007	20,020,000	9.04				Yes		(9,700)
3Q 2007	20,240,000	9.04				Yes		(10,526)
4Q 2007	20,240,000	9.56				Yes		(11,900)
1Q 2008	14,105,000	10.28				Yes		(9,199)
2Q 2008	14,105,000	7.94				Yes		(10,122)
3Q 2008	14,260,000	7.96				Yes		(10,140)
4Q 2008	14,260,000	8.48				Yes		(10,492)
Basis Protection Swaps:								
1Q 2006	34,200,000				(0.33)	No		66,338
2Q 2006	30,940,000				(0.31)	No		21,892
3Q 2006	31,280,000				(0.31)	No		17,380
4Q 2006	33,720,000				(0.32)	No		22,268
1Q 2007	32,850,000				(0.29)	No		24,990
2Q 2007	34,125,000				(0.35)	No		23,208
3Q 2007	34,500,000				(0.35)	No		18,471
4Q 2007	35,720,000				(0.32)	No		20,078
1Q 2008	33,215,000				(0.29)	No		19,800
2Q 2008	26,845,000				(0.25)	No		17,689
3Q 2008	27,140,000				(0.25)	No		14,136
4Q 2008	31,410,000				(0.28)	No		12,716
1Q 2009	26,100,000				(0.32)	No		9,076
2Q 2009	20,020,000				(0.28)	No		8,026
3Q 2009	20,240,000				(0.28)	No		5,505
4Q 2009	20,240,000				(0.28)	No		5,735
Cap-Swaps:								
1Q 2006	7,200,000	7.11	5.06			No		(28,331)
2Q 2006	11,830,000	6.84	5.13			No		(40,761)
3Q 2006	11,960,000	6.85	5.13			No		(42,622)
4Q 2006	11,960,000	6.89	5.13			No		(49,342)
Counter Swaps:								
1Q 2006	(1,800,000)	(6.19)				No		9,267
2Q 2006	(1,820,000)	(5.35)				No		9,062
3Q 2006	(1,840,000)	(5.33)				No		9,353
4Q 2006	(1,840,000)	(5.50)				No		10,103
Call Options:								
1Q 2006	1,800,000			12.50		No	1,890	(821)
2Q 2006	1,820,000			12.50		No	1,911	(781)
3Q 2006	1,840,000			12.50		No	1,932	(1,348)
4Q 2006	1,840,000			12.50		No	1,932	(2,408)
1Q 2007	1,800,000			12.50		No	1,890	(3,559)
2Q 2007	1,820,000			12.50		No	1,911	(1,285)
3Q 2007	1,840,000			12.50		No	1,932	(1,423)
4Q 2007	1,840,000			12.50		No	1,932	(2,371)
1Q 2008	1,820,000			12.50		No	1,911	(3,754)

2Q 2008	1,820,000	12.50	No	1,911	(893)
3Q 2008	1,840,000	12.50	No	1,932	(1,043)
4Q 2008	1,840,000	12.50	No	1,932	(1,775)

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	Volume	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, 2005 ($ in thousands)
Collars:								
1Q 2006	180,000		6.00	9.70		Yes		(270)
Locked Swaps:								
1Q 2006	6,300,000					No		(7,598)
2Q 2006	6,370,000					No		(5,199)
3Q 2006	6,440,000					No		(5,099)
4Q 2006	6,440,000					No		(4,706)
1Q 2007	6,300,000					No		(4,789)
2Q 2007	6,370,000					No		(2,517)
3Q 2007	6,440,000					No		(2,049)
4Q 2007	6,440,000					No		(2,272)
Floating-Price Swaps:								
1Q 2006	(2,700,000)	(7.96)				No		2,607
Total Natural Gas							23,016	(264,142)
Oil (bbls):								
Swaps:								
1Q 2006	900,000	60.00				Yes		(1,739)
2Q 2006	880,000	59.88				Yes		(2,760)
3Q 2006	828,000	60.16				Yes		(2,858)
4Q 2006	828,000	59.78				Yes		(3,415)
1Q 2007	360,000	57.13				Yes		(2,495)
2Q 2007	91,000	51.04				Yes		(1,200)
3Q 2007	92,000	50.56				Yes		(1,233)
4Q 2007	92,000	50.11				Yes		(1,236)
Cap-Swaps:								
1Q 2006	135,000	57.82	40.67			No		(565)
2Q 2006	136,500	57.82	40.67			No		(825)
3Q 2006	138,000	57.82	40.67			No		(1,057)
4Q 2006	92,000	56.53	40.00			No		(917)
Total Oil								(20,300)
Total Natural Gas and Oil							$ 23,016	$ (284,442)

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, 2005.

Based upon the market prices at December 31, 2005, we expect to transfer approximately $153.8 million (net of income taxes) of the loss included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually occur. All transactions hedged as of December 31, 2005 are expected to mature by December 31, 2009.

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

	December 31,		
	2005	2004	2003
		($ in thousands)	
Fair value of contracts outstanding, as of January 1	$ 38,350	$ (44,988)	$ (14,533)
Change in fair value of contracts during the period	(771,076)	(69,927)	(31,078)
Contracts realized or otherwise settled during the period	401,684	154,901	17,389
Fair value of new contracts when entered into during the period	(614,772)	(5,369)	(16,766)
Fair value of contracts when closed during the period		3,733	
Fair value of contracts outstanding, as of December 31	$ (945,814)	$ 38,350	$ (44,988)

The change in the fair value of our derivative instruments since January 1, 2005 resulted mainly from an increase in oil and 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 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.

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition. 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 is 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 will result in adjustments to our oil and 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 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 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 have hedged the production volumes listed below 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 will be reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

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The following details the CNR derivatives we have assumed:

	Volume	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, 2005 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
1Q 2006	7,872,500	4.91			Yes	(50,693)
2Q 2006	10,510,500	4.86			Yes	(56,501)
3Q 2006	10,626,000	4.86			Yes	(57,355)
4Q 2006	10,626,000	4.86			Yes	(62,483)
1Q 2007	10,350,000	4.82			Yes	(68,401)
2Q 2007	10,465,000	4.82			Yes	(46,158)
3Q 2007	10,580,000	4.82			Yes	(46,442)
4Q 2007	10,580,000	4.82			Yes	(51,557)
1Q 2008	9,555,000	4.68			Yes	(53,954)
2Q 2008	9,555,000	4.68			Yes	(33,892)
3Q 2008	9,660,000	4.68			Yes	(33,999)
4Q 2008	9,660,000	4.66			Yes	(38,487)
1Q 2009	4,500,000	5.18			Yes	(18,772)
2Q 2009	4,550,000	5.18			Yes	(10,450)
3Q 2009	4,600,000	5.18			Yes	(10,508)
4Q 2009	4,600,000	5.18			Yes	(12,616)
Total						(652,268)
Collars:						
1Q 2009	900,000		4.50	6.00	Yes	(3,380)
2Q 2009	910,000		4.50	6.00	Yes	(1,754)
3Q 2009	920,000		4.50	6.00	Yes	(1,773)
4Q 2009	920,000		4.50	6.00	Yes	(2,197)
Total						(9,104)
Total Natural Gas						$ (661,372)

In connection with the November 14, 2005 acquisition of Columbia Natural Resources, LLC (CNR), Chesapeake assumed obligations under forward gas sales agreements with Mahonia II Limited (Mahonia) to deliver a total of 8.9 bcf of natural gas to Mahonia through February 2006. As of December 31, 2005, the remaining 4.25 bcf of gas scheduled to be delivered under this contract has been recorded as a $60.9 million current accrued liability, based on the fair value of the delivery commitment at the date of acquisition.

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Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of December 31, 2005, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	2006	2007	2008	2009	2010	Years of Maturity Thereafter ($ in millions)	Total	Fair Value
Liabilities:								
Long-term debt fixed-rate (a)	$	$	$	$	$	$ 5,524.7	$ 5,524.7	$ 5,582.4
Average interest rate						6.3%	6.3%	6.3%
Long-term debt variable rate	$	$	$	$	$	$ 72.0	$ 72.0	$ 72.0
Average interest rate						7.3%	7.3%	7.3%

(a) This amount does not include the discount included in long-term debt of ($95.6) million and the discount for interest rate swaps of ($11.3) 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 of interest rate derivatives 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. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

As of December 31, 2005, the following interest rate swaps were 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 Gain (Loss) ($ in thousands)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,734)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	$ (5,133)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	$ (5,327)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	$ (5,004)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	$ (1,344)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	$ (3,240)
October 2005 January 2016	$ 200,000,000	6.625%	6 month LIBOR plus 129 basis points	$ 282

In January 2006, we closed the interest rate swap on our 6.625% Senior Notes for $1.0 million. Subsequent to December 31, 2005, 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	Floating Rate

		Amount	
January 2006	January 2016	$ 250,000,000	6 month LIBOR plus 129 basis points
March 2006	January 2016	$ 250,000,000	6 month LIBOR plus 120 basis points
March 2006	August 2017	$ 250,000,000	6 month LIBOR plus 125.5 basis points

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In 2005, we closed various interest rate swaps for gains totaling $7.1 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.

In March 2004, Chesapeake entered into an interest rate swap which required Chesapeake to pay a fixed rate of 8.68% while the counterparty paid Chesapeake a floating rate of six month LIBOR plus 0.75% on a notional amount of $142.7 million. On March 15, 2005, we elected to terminate the interest rate swap and paid $31.8 million to the counterparty.

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.

Our evaluation of and conclusion on the effectiveness of internal control over financial reporting excludes Columbia Energy Resources, LLC, which we acquired in a purchase business combination on November 14, 2005. The acquisition of Columbia Energy Resources, LLC accounted for approximately twenty percent of our total assets at December 31, 2005, and contributed approximately two percent of our total revenue in fiscal 2005. See Note 13 for additional information regarding the acquisition.

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, 2005.

Our management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2005 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

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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 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 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.

As discussed in Note 12 to the consolidated financial statements, effective January 1, 2003, the Company changed the manner in which it accounts for asset retirement obligations.

Internal control over financial reporting

Also, in our opinion, management s assessment, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2005 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, 2005, 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.

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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.

As described in Management s Report on Internal Control Over Financial Reporting, management has excluded Columbia Energy Resources, LLC from its assessment of internal control over financial reporting as of December 31, 2005 because it was acquired by the Company in a purchase business combination in November 2005. We have also excluded Columbia Energy Resources, LLC from our audit of internal control over financial reporting. Columbia Energy Resources, LLC is a wholly-owned subsidiary whose total assets and total revenues represent twenty percent and two percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2005.

PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma

March 13, 2006

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 60,027	$ 6,896
Accounts receivable:		
Oil and gas sales	615,382	347,081
Joint interest, net of allowances of $4,904,000 and $4,648,000, respectively	84,765	68,220
Related parties	12,839	8,286
Other	78,208	35,781
Deferred income tax asset	234,592	18,068
Short-term derivative instruments	10,503	51,061
Inventory and other	87,081	32,147
Total Current Assets	1,183,397	567,540
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	15,880,919	9,451,413
Unevaluated properties	1,739,095	761,785
Less: accumulated depreciation, depletion and amortization of oil and gas properties	(3,945,703)	(3,057,742)
Total oil and gas properties, at cost based on full-cost accounting	13,674,311	7,155,456
Other property and equipment	750,083	324,495
Drilling rigs	116,133	49,375
Less: accumulated depreciation and amortization of other property, equipment and drilling rigs	(128,640)	(84,942)
Total Property and Equipment	14,411,887	7,444,384
OTHER ASSETS:		
Investment in Pioneer Drilling Company	138,095	65,950
Other investments	159,348	26,793
Long-term derivative instruments	78,860	44,169
Other assets	146,875	95,673
Total Other Assets	523,178	232,585
TOTAL ASSETS	$ 16,118,462	$ 8,244,509

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	December 31, 2005	December 31, 2004
	($ in thousands)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 516,792	$ 367,176
Short-term derivative instruments	577,681	91,414
Other accrued liabilities	364,501	222,029
Revenues and royalties due others	394,693	216,820
Accrued interest	110,421	66,514
Total Current Liabilities	1,964,088	963,953
LONG-TERM LIABILITIES:		
Long-term debt, net	5,489,742	3,075,109
Deferred income tax liability	1,804,978	933,873
Asset retirement obligation	156,593	73,718
Long-term derivative instruments	479,996	1,296
Revenues and royalties due others	22,585	17,007
Other liabilities	26,157	16,670
Total Long-Term Liabilities	7,980,051	4,117,673
CONTINGENCIES AND COMMITMENTS (Note 4)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
6.00% cumulative convertible preferred stock, 99,310 and 103,110 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $4,965,500 and $5,155,500	4,966	5,156
5.00% cumulative convertible preferred stock (Series 2003), 1,025,946 and 1,725,000 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $102,594,600 and $172,500,000	102,595	172,500
4.125% cumulative convertible preferred stock, 89,060 and 313,250 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $89,060,000 and $313,250,000	89,060	313,250
5.00% cumulative convertible preferred stock (Series 2005), 4,600,000 and 0 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $460,000,000	460,000	
4.50% cumulative convertible preferred stock, 3,450,000 and 0 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $345,000,000	345,000	
5.00% cumulative convertible preferred stock (Series 2005B), 5,750,000 and 0 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $575,000,000	575,000	
Common Stock, $.01 par value, 500,000,000 shares authorized, 375,510,521 and 316,940,784 shares issued December 31, 2005 and 2004, respectively	3,755	3,169
Paid-in capital	3,803,312	2,440,105
Retained earnings	1,100,841	262,987
Accumulated other comprehensive income (loss), net of tax of $112,071,000 and ($11,489,000), respectively	(194,972)	20,425
Unearned compensation	(89,242)	(32,618)
Less: treasury stock, at cost; 5,320,816 and 5,072,121 common shares as of December 31, 2005 and 2004, respectively	(25,992)	(22,091)
Total Stockholders Equity	6,174,323	3,162,883

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 16,118,462	$ 8,244,509

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2005	2004	2003
	($ in thousands, except per share data)		
REVENUES:			
Oil and gas sales	$ 3,272,585	$ 1,936,176	$ 1,296,822
Oil and gas marketing sales	1,392,705	773,092	420,610
Total Revenues	4,665,290	2,709,268	1,717,432
OPERATING COSTS:			
Production expenses	316,956	204,821	137,583
Production taxes	207,898	103,931	77,893
General and administrative expenses	64,272	37,045	23,753
Oil and gas marketing expenses	1,358,003	755,314	410,288
Oil and gas depreciation, depletion and amortization	894,035	582,137	369,465
Depreciation and amortization of other assets	50,966	29,185	16,793
Provision for legal settlements		4,500	6,402
Total Operating Costs	2,892,130	1,716,933	1,042,177
INCOME FROM OPERATIONS	1,773,160	992,335	675,255
OTHER INCOME (EXPENSE):			
Interest and other income	10,452	4,476	2,827
Interest expense	(219,800)	(167,328)	(154,356)
Loss on repurchases or exchanges of Chesapeake debt	(70,419)	(24,557)	(20,759)
Loss on investment in Seven Seas Petroleum, Inc.			(2,015)
Total Other Income (Expense)	(279,767)	(187,409)	(174,303)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	1,493,393	804,926	500,952
INCOME TAX EXPENSE:			
Current			5,000
Deferred	545,091	289,771	185,360
Total Income Tax Expense	545,091	289,771	190,360
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	948,302	515,155	310,592
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF INCOME TAXES OF $1,464,000			2,389
NET INCOME	948,302	515,155	312,981
PREFERRED STOCK DIVIDENDS	(41,813)	(39,506)	(22,469)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(26,874)	(36,678)	
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 879,615	$ 438,971	$ 290,512
EARNINGS PER COMMON SHARE BASIC:			
Income before cumulative effect of accounting change	$ 2.73	$ 1.73	$ 1.36
Cumulative effect of accounting change			0.02
	$ 2.73	$ 1.73	$ 1.38

EARNINGS PER COMMON SHARE ASSUMING DILUTION:						
Income before cumulative effect of accounting change	$	2.51	$	1.53	$	1.20
Cumulative effect of accounting change						0.01
	$	2.51	$	1.53	$	1.21
CASH DIVIDEND DECLARED PER COMMON SHARE	$	0.195	$	0.170	$	0.135
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):						
Basic		322,034		253,212		211,203
Assuming dilution		366,683		305,718		258,567

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2005	**2004**	**2003**
		($ in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME	$ 948,302	$ 515,155	$ 312,981
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion, and amortization	935,965	605,593	382,004
Deferred income taxes	544,891	289,532	186,664