CHESAPEAKE ENERGY CORP
Form 10-K
March 02, 2009
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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, 2008

¨ 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
7.625% Senior Notes due 2013	New York Stock Exchange
7.0% Senior Notes due 2014	New York Stock Exchange

7.5% Senior Notes due 2014	New York Stock Exchange
6.375% Senior Notes due 2015	New York Stock Exchange
9.5% Senior Notes due 2015	New York Stock Exchange
6.625% Senior Notes due 2016	New York Stock Exchange
6.875% Senior Notes due 2016	New York Stock Exchange
6.5% Senior Notes due 2017	New York Stock Exchange
6.25% Senior Notes due 2018	New York Stock Exchange
7.25% Senior Notes due 2018	New York Stock Exchange
6.875% Senior Notes due 2020	New York Stock Exchange
2.75% Contingent Convertible Senior Notes due 2035	New York Stock Exchange
2.5% Contingent Convertible Senior Notes due 2037	New York Stock Exchange
2.25% Contingent Convertible Senior Notes due 2038	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	New York Stock Exchange
6.25% Mandatory Convertible Preferred Stock	New York Stock Exchange

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES 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, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer x Accelerated Filer ¨ Non-accelerated Filer ¨ Smaller Reporting Company ¨

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, 2008 was approximately $29.5 billion. At February 26, 2009, there were 624,477,656 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2009 Annual Meeting of Shareholders are incorporated by reference in Part III.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

2008 ANNUAL REPORT ON FORM 10-K

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PART I

ITEM 1. *Business*
General

We are the largest independent producer of natural gas in the United States. We own interests in approximately 41,200 producing natural gas and oil wells that are currently producing approximately 2.3 billion cubic feet equivalent (bcfe) per day, 92% of which is natural gas. Our strategy is focused on discovering, developing and acquiring conventional and unconventional natural gas reserves onshore in the U.S., primarily in the Big 4 natural gas shale plays: the Barnett Shale in the Forth Worth Basin of north-central Texas, the Haynesville Shale in the Ark-La-Tex area of northwestern Louisiana and East Texas, the Fayetteville Shale in the Arkoma Basin of central Arkansas and the Marcellus Shale in the northern Appalachian Basin of West Virginia, Pennsylvania and New York. We also have substantial operations in various other plays, both conventional and unconventional, in the Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the U.S.

We have been developing expertise in horizontal drilling technology since shortly after our inception in 1989 and have focused almost exclusively on developing natural gas properties in the U.S. since 2000. We were one of the first companies to recognize the potential of unconventional natural gas properties, especially shales, in the U.S. during the early part of this decade. During the past five years, we have grown from the eighth largest natural gas producer in the U.S. to the largest independent natural gas producer, in large part as a result of our success in finding and developing unconventional natural gas assets.

As of December 31, 2008, we had 12.051 trillion cubic feet equivalent, or tcfe, of proved reserves, of which 94% were natural gas and all of which were onshore in the U.S. During 2008, we produced an average of 2.303 bcfe per day, an 18% increase over the 1.957 bcfe per day produced in 2007. We replaced our 843 bcfe of production with an internally estimated 2.015 tcfe of new proved reserves for a reserve replacement rate of 239%. Reserve replacement through the drillbit was 2.545 tcfe, or 302% of production including 1.248 tcfe of positive performance revisions and 298 bcfe of negative revisions resulting from natural gas and oil price decreases between December 31, 2007 and December 31, 2008. Reserve replacement through the acquisition of proved reserves was 172 bcfe. During 2008, we divested 702 bcfe of estimated proved reserves. In total, our proved reserves grew by 11% during 2008, from 10.9 tcfe to 12.1 tcfe. Of our 12.1 tcfe of proved reserves, 67% were proved developed reserves.

During 2008, Chesapeake continued the industry s most active drilling program and drilled 1,819 gross (1,491 net) operated wells and participated in another 1,857 gross (242 net) wells operated by other companies. The company s drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during 2008, we invested $5.043 billion in operated wells (using an average of 145 operated rigs) and $754 million in non-operated wells (using an average of 110 non-operated rigs) for total drilling, completing and equipping costs of $5.797 billion.

During the second half of 2008, we entered into joint venture arrangements that monetized a portion of our investment in three of the Big 4 Shale plays and provide drilling cost carries for our retained interest. In the Haynesville Shale, we entered into a joint venture with Plains Exploration & Production Company in July 2008 in which we sold Plains a 20% interest in our Haynesville properties and received an upfront cash payment of $1.65 billion and drilling cost carries of up to $1.65 billion. In the Fayetteville Shale, we entered into a joint venture with BP America Production Company in September 2008 in which we sold BP a 25% interest in our Fayetteville properties and received an upfront cash payment of $1.1 billion and drilling cost carries of $800 million. Most recently, we entered into a joint venture with StatoilHydro ASA in November 2008 in which we sold a 32.5% interest in our Marcellus properties and received an upfront cash payment of $1.25 billion and drilling cost carries of $2.125 billion. Collectively in these three joint ventures, we received upfront cash payments of $4.0 billion and future drilling cost carries of up to $4.6 billion for total consideration of up to $8.6 billion against a cost basis of approximately $1.2 billion in the property interests we sold. Moreover, Chesapeake retained an 80% interest in the Haynesville Shale properties, a 75% interest in the Fayetteville Shale properties and a 67.5% interest in the Marcellus Shale properties.

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.chk.com* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. References to us , we and our in this report refer to Chesapeake Energy Corporation together with its subsidiaries.

Business Strategy

Since our inception in 1989, Chesapeake s goal has been to create value for investors by building one of the largest onshore natural gas resource bases in the United States. For the past eleven years, our strategy to accomplish this goal has been to focus on developing unconventional plays onshore in the U.S., where we believe we can generate the most attractive risk adjusted returns. In building our industry-leading natural gas resource base during the period from 1998 to 2008, we integrated an aggressive and technologically-advanced drilling program with an active property consolidation program focused on small to medium-sized corporate and property acquisitions. During the past two years, we have shifted our strategy from drilling inventory capture to drilling inventory conversion. In doing so, we have de-emphasized acquisitions of proved properties while further emphasizing our industry-leading drilling program and converting our substantial backlog of drilling opportunities into proved developed producing reserves through the drillbit. Key elements of this business strategy are further explained below.

Grow through the Drillbit. We believe that our most distinctive characteristic is our commitment and ability to grow production and reserves organically through the drillbit. We are currently utilizing 112 operated drilling rigs and 75 non-operated drilling rigs to conduct the most active drilling program in the U.S. We are active in most of the unconventional plays in the U.S., where we drill more horizontal wells than any other company in the industry. For several years, we have been actively investing in leasehold, 3-D seismic information and human capital to take full advantage of our capacity to grow through the drillbit. We are one of the few large-cap independent natural gas and oil companies that have been able to consistently increase production, which we have successfully achieved for the past 19 consecutive years. We believe the key elements of the success and scale of our drilling programs have been our recognition earlier than most of our competitors that (i) natural gas and oil prices, while remaining cyclical and volatile, were likely to move structurally higher for an extended period, (ii) new horizontal drilling and completion techniques would enable development of previously uneconomic natural gas reservoirs and (iii) various shale formations could be recognized and developed as potentially prolific natural gas reservoirs rather than just as source rocks for conventional natural gas reservoirs. In response to our early recognition of these trends, we have proactively hired thousands of new employees and have built the nation s largest onshore leasehold and 3-D seismic inventories. These stand as the building blocks of our successful large-scale drilling program and the foundation of value creation for our company.

Control Substantial Land and Drilling Location Inventories. After we identified the trends discussed above, we initiated a plan to build and maintain the largest inventory of onshore drilling opportunities in the U.S. Anticipating an increase in natural gas and oil prices and recognizing that better horizontal drilling and completion technologies when applied to various new shale plays would likely create a unique opportunity to capture decades worth of drilling opportunities, we embarked on a very aggressive lease acquisition program which we have referred to as the land grab . We believed that the winner of the land grab would enjoy a distinctive competitive advantage for decades to come as other companies would be locked out of the best new shale plays in the U.S. We believe that we have executed our land grab strategy with particular distinction. We now own approximately 15 million net acres of leasehold in the U.S. and have identified more than 36,000 drilling opportunities on this leasehold. We believe this deep backlog of drilling, more than ten years worth at current drilling levels, provides unusual confidence and transparency into our future growth capabilities.

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Develop Proprietary Technological Advantages. In addition to our industry-leading leasehold position, we have developed a number of proprietary technological advantages. First, we have acquired what we believe is the nation s largest inventory of three-dimensional (3-D) seismic information. Possessing this 3-D seismic data enables us to image reservoirs of natural gas that might otherwise remain undiscovered and to drill our horizontal wells more accurately inside the targeted shale formation and avoid various underground geohazards such as faults and karsts. In addition, we have developed an industry-leading information-gathering program that gives us insight into new plays and competitor activity. As a result of our initiatives, we now produce approximately 4% of the nation s natural gas, drill 13% of its wells and participate in almost an equal number of wells drilled by others. By gathering this information on a real-time basis, then quickly assimilating and analyzing the information, we are able to react quickly to opportunities that are created through our drilling program and those of our competitors. Furthermore, we have established a unique state-of-the-art Reservoir Technology Center (RTC) in Oklahoma City. The RTC enables us to more quickly, accurately and confidentially analyze core data from shale wells on a proprietary basis and then identify new plays and leasing opportunities ahead of our competition to improve existing plays. It also allows us to design fracture stimulation procedures that might work most productively in the shale formations that we aggressively drill. We believe the RTC provides a very substantial competitive advantage in developing new shale plays and improving existing shale plays.

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, including superior geoscientific and engineering information, 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. By focusing most of our future activities in the Big 4 shale plays, we will continue to achieve even greater regional scale in north Texas for the Barnett, northwestern Louisiana and East Texas for the Haynesville, central Arkansas for the Fayetteville and northeastern and southwestern Pennsylvania and northern West Virginia for the Marcellus.

Focus on Low Costs. By proactively hedging the prices we receive for a majority of our natural gas and oil production and by minimizing lease operating costs and general and administrative expenses through focused activities and increased scale, we have been able to deliver attractive profit margins and 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, extensive and competitive services and natural gas processing and transportation infrastructures that exist in our key operating areas. In addition, to control costs and service provider quality, we have made significant investments in our drilling rig and trucking service operations and in our midstream gathering and compression operations. As of December 31, 2008, we operated approximately 23,800 of our 41,200 wells, which delivered approximately 86% of our daily production volume. This large percentage of operated properties provides us with a high degree of operating flexibility and cost control.

Mitigate Natural Gas and Oil Price Risk. We have used and intend to continue using hedging programs to mitigate the risks inherent in developing and producing natural gas and oil 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. As of February 17, 2009, we have natural gas and oil swaps and collars in place covering 78% and 48% of our expected production in 2009 and 2010, at average prices of $7.71 per mcfe and $9.02 per mcfe, respectively, thereby providing price certainty for a substantial portion of our future cash flow.

Form Unique Joint Venture Arrangements. In the second half of 2008, the company entered into three joint venture arrangements covering three of the company s Big 4 shale plays. In the joint ventures, the company has collaborated with other leading energy companies to accelerate the development of the company s properties in the Haynesville Shale, the Fayetteville Shale and the Marcellus Shale. In total, we sold leasehold and producing property assets in which we had a cost basis of approximately $1.2 billion to these three joint venture

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partners for total cash consideration of $4.0 billion and up to $4.6 billion of future drilling cost carries while we retained a majority interest in each joint venture. The drilling cost carries of up to approximately $4.2 billion that remain unused as of December 31, 2008 will be extremely valuable in the years ahead by enabling the company to develop reserves in these joint venture shale plays at greatly reduced costs. We are also considering opportunities for other joint venture transactions to develop our properties.

Maintain an Entrepreneurial Culture. Chesapeake was formed in 1989 with an initial capitalization of $50,000 and fewer than ten employees. We completed our initial public offering of common stock in early 1993 and subsequent to those early corporate milestones, our management team has guided the company through various operational and industry challenges and extremes of natural gas and oil prices to create the largest independent producer of natural gas in the U.S. with approximately 7,600 employees currently. The company takes pride in its innovative and aggressive implementation of its business strategy and strives to be as entrepreneurial today as it has been in its past. We have maintained an unusually flat organizational structure as we have grown to help ensure that important information travels rapidly through the company and decisions are made and implemented quickly.

Improve our Balance Sheet. We have made significant progress in improving our balance sheet over the past ten years. From December 31, 1998 through December 31, 2008, we increased our stockholders equity by $16.5 billion through a combination of earnings and common and preferred equity issuances. As of December 31, 2008, our debt as a percentage of total capitalization (total capitalization is the sum of debt less cash on hand and stockholders equity) was 43%, compared to 131% as of December 31, 1998 and 47% as of December 31, 2007.

Outlook

We believe that demand for natural gas will increase in the U.S. and around the world because of its favorable environmental characteristics and relative abundance. This outlook is gathering more national attention when compared to oil, which is likely to return to being in increasingly short supply once the current worldwide recession is over, and to coal, which has many unfavorable environmental characteristics. Chesapeake s strategy for 2009 is to continue developing our natural gas assets, especially in our Big 4 Shale plays, in which we anticipate investing approximately 70% of our drilling capital in 2009, through exploratory and developmental drilling and by selectively acquiring strategic properties in the Mid-Continent and in our other operating areas. We project that our 2009 production will be between 875 bcfe and 885 bcfe, a 4% to 5% increase over 2008 production. We have budgeted $3.3 billion to $3.6 billion for drilling, acreage acquisition, seismic and related capitalized internal costs, which is expected to be funded with operating cash flow based on our current assumptions, our 2009-2010 financial plan and borrowings under our revolving bank credit facility. Our budget is frequently adjusted based on changes in natural gas and oil prices, drilling results, drilling costs and other factors.

Operating Areas

Chesapeake focuses its natural gas exploration, development and acquisition efforts in the six operating areas described below.

Mid-Continent (including the Fayetteville Shale). Chesapeake s Mid-Continent proved reserves of 4.456 tcfe represented 37% of our total proved reserves as of December 31, 2008, and this area produced 413 bcfe, or 49%, of our 2008 production. During 2008, we invested approximately $2.3 billion to drill 2,096 (714 net) wells in the Mid-Continent. For 2009, we anticipate spending approximately $610 million, or 21% of our total budget for exploration and development activities, net of carries, in the Mid-Continent region. BP, our Fayetteville Shale joint venture partner, has committed to pay up to $800 million of our drilling, completing and equipping costs in the play. Of the total $800 million drilling cost carry, $256 million was applied in 2008, and we expect the remaining $544 million will be applied in 2009.

Barnett Shale. Chesapeake s Barnett Shale proved reserves represented 2.935 tcfe, or 24%, of our total proved reserves as of December 31, 2008. During 2008, the Barnett Shale assets produced 181 bcfe, or 22%, of our total production. During 2008, we invested approximately $1.9 billion to drill 776 (600 net) wells in the Barnett Shale. For 2009, we anticipate spending approximately $1.275 billion, or 44% of our total budget for exploration and development activities in the Barnett Shale.

Appalachian Basin (including the Marcellus Shale). Chesapeake s Appalachian Basin proved reserves represented 1.569 tcfe, or 13%, of our total proved reserves as of December 31, 2008. During 2008, the Appalachian assets produced 36 bcfe, or 4%, of our total production. During 2008, we invested approximately $379 million to drill 161 (137 net) wells in the Appalachian Basin. For 2009, we anticipate spending approximately $145 million, or 5% of our total budget for exploration and development activities, net of carries, in the Appalachian Basin. StatoilHydro, our Marcellus Shale joint venture partner, will pay 75% of our drilling, completing and equipping costs in the play over the next few years. Of the total $2.125 billion drilling cost carry, we expect approximately $250 million will be applied in 2009.

Ark-La-Tex (including the Haynesville Shale). Chesapeake s Ark-La-Tex proved reserves represented 1.231 tcfe, or 10%, of our total proved reserves as of December 31, 2008. During 2008, the Ark-La-Tex assets produced 62 bcfe, or 7%, of our total production. During 2008, we invested approximately $429 million to drill 413 (136 net) wells in the Ark-La-Tex region. For 2009, we anticipate spending approximately $580 million, or 20% of our total budget for exploration and development activities, net of carries, in the Ark-La-Tex area. Plains Exploration & Production Company, our Haynesville Shale joint venture partner, will pay 50% of our drilling, completing and equipping costs in the play over the next few years. Of the total $1.65 billion drilling cost carry, $72 million was applied in 2008, and we expect approximately $425 million will be applied in 2009.

On February 20, 2009, we amended our joint venture agreement with Plains to provide Plains a one-time option, exercisable between June 15, 2010 and June 30, 2010, to reduce its maximum drilling cost carry obligation by $800 million in exchange for assigning us, effective December 31, 2010, 50% of its interest in the Haynesville joint venture properties. Chesapeake believes Plains cost basis in the properties that would be assigned to us upon exercise of the option could approximate $1.5 billion to $1.6 billion by December 31, 2010. If Plains exercises the option and has funded more than $850 million of its drilling cost carry as of December 31, 2010, we will be required to pay to Plains an amount equal to such excess. We will not be required to refund to Plains any of the $1.65 billion in cash consideration paid in July 2008 or any portion of the first $850 million in drilling cost carries to be paid by Plains.

South Texas and Texas Gulf Coast. Chesapeake s South Texas and Texas Gulf Coast proved reserves represented 943 bcfe, or 8%, of our total proved reserves as of December 31, 2008. During 2008, the South Texas and Texas Gulf Coast assets produced 71 bcfe, or 8%, of our total production. For 2008, we invested approximately $235 million to drill 65 (51 net) wells in the South Texas and Texas Gulf Coast regions. For 2009, we anticipate spending approximately $90 million, or 3% of our total budget for exploration and development activities in the South Texas and Texas Gulf Coast regions.

Permian and Delaware Basins. Chesapeake s Permian and Delaware Basin proved reserves represented 917 bcfe, or 8%, of our total proved reserves as of December 31, 2008. During 2008, the Permian assets produced 80 bcfe, or 10%, of our total production. During 2008, we invested approximately $841 million to drill 165 (95 net) wells in the Permian and Delaware Basins. For 2009, we anticipate spending approximately $200 million, or 7% of our total budget for exploration and development activities in the Permian and Delaware Basins.

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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.

	2008				2007				2006			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Development:												
Productive	3,479	99%	1,650	99%	3,439	98%	1,792	99%	2,844	98%	1,364	99%
Non-productive	40	1	13	1	53	2	10	1	47	2	13	1
Total	3,519	100%	1,663	100%	3,492	100%	1,802	100%	2,891	100%	1,377	100%
Exploratory:												
Productive	142	90%	63	90%	177	99%	116	99%	128	98%	71	99%
Non-productive	15	10	7	10	2	1	1	1	3	2	1	1
Total	157	100%	70	100%	179	100%	117	100%	131	100%	72	100%

The following table shows the wells we drilled by area:

	2008		2007		2006	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Mid-Continent	2,096	714	2,126	785	1,884	621
Barnett Shale	776	600	512	410	244	187
Appalachian Basin	161	137	431	374	319	272
Ark-La-Tex	413	136	259	176	248	175
South Texas and Texas Gulf Coast	65	51	90	67	138	102
Permian and Delaware Basins	165	95	253	107	189	92
Total	3,676	1,733	3,671	1,919	3,022	1,449

At December 31, 2008, we had 166 (83 net) wells in process.

Well Data

At December 31, 2008, we had interests in approximately 41,200 (22,813 net) producing wells, including properties in which we held an overriding royalty interest, of which 6,900 (3,840 net) were classified as primarily oil producing wells and 34,300 (18,973 net) were classified as primarily natural gas producing wells. Chesapeake operates approximately 23,800 of its 41,200 producing wells. During 2008, we drilled 1,819 (1,491 net) wells and participated in another 1,857 (242 net) wells operated by other companies. We operate approximately 86% 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, natural gas and oil sales, average sales prices received, other operating income and expenses for the periods indicated:

	Years Ended December 31,		
	2008	2007	2006
Net Production:			
Natural gas (mmcf)	775,424	654,969	526,459
Oil (mbbls)	11,220	9,882	8,654
Natural gas equivalent (mmcfe)	842,744	714,261	578,383
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 6,003	$ 4,117	$ 3,343
Natural gas derivatives realized gains (losses)	267	1,214	1,269
Natural gas derivatives unrealized gains (losses)	521	(139)	467
Total natural gas sales	6,791	5,192	5,079
Oil sales	1,066	678	527
Oil derivatives realized gains (losses)	(275)	(11)	(15)
Oil derivatives unrealized gains (losses)	276	(235)	28
Total oil sales	1,067	432	540
Total natural gas and oil sales	$ 7,858	$ 5,624	$ 5,619
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 7.74	$ 6.29	$ 6.35
Oil ($ per bbl)	$ 95.04	$ 68.64	$ 60.86
Natural gas equivalent ($ per mcfe)	$ 8.39	$ 6.71	$ 6.69
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 8.09	$ 8.14	$ 8.76
Oil ($ per bbl)	$ 70.48	$ 67.50	$ 59.14
Natural gas equivalent ($ per mcfe)	$ 8.38	$ 8.40	$ 8.86
Other Operating Income ($ per mcfe):			
Natural gas and oil marketing	$ 0.11	$ 0.10	$ 0.09
Service operations	$ 0.04	$ 0.06	$ 0.11
Expenses ($ per mcfe):			
Production expenses	$ 1.05	$ 0.90	$ 0.85
Production taxes	$ 0.34	$ 0.30	$ 0.31
General and administrative expenses	$ 0.45	$ 0.34	$ 0.24
Natural gas and oil depreciation, depletion and amortization	$ 2.34	$ 2.57	$ 2.35
Depreciation and amortization of other assets	$ 0.21	$ 0.22	$ 0.18
Interest expense (a)	$ 0.27	$ 0.51	$ 0.52

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

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Natural Gas and Oil Reserves

The tables below set forth information as of December 31, 2008 with respect to our estimated proved reserves, the associated estimated future net revenue and present value (discounted at an annual rate of 10%) of estimated future net revenue before and after income tax (standardized measure) at such date. Neither the pre-tax present value of estimated future net revenue nor the after-tax standardized measure is intended to represent the current market value of the estimated natural gas and oil reserves we own.

	December 31, 2008		
	Gas (mmcf)	Oil (mbbl)	Total (mmcfe)
Proved developed	7,581,523	84,913	8,091,002
Proved undeveloped	3,745,932	35,719	3,960,247
Total proved	11,327,455	120,632	12,051,249

	Proved Developed	Proved Undeveloped ($ in millions)	Total Proved
Estimated future net revenue (a)	$ 27,433	$ 9,356	$ 36,789
Present value of estimated future net revenue (a)	$ 13,274	$ 2,327	$ 15,601
Standardized measure (a) (b)			$ 11,833

	Gas (mmcf)	Oil (mbbl)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value ($ in millions)
Mid-Continent	4,040,382	69,314	4,456,266	37%	$ 5,807
Barnett Shale	2,934,292	153	2,935,208	24	3,990
Appalachian Basin	1,561,418	1,249	1,568,914	13	1,025
Ark-La-Tex	1,222,835	1,385	1,231,148	10	2,116
South Texas and Texas Gulf Coast	903,921	6,476	942,779	8	1,472
Permian and Delaware Basins	664,607	42,055	916,934	8	1,191
Total	11,327,455	120,632	12,051,249	100%	$ 15,601(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, 2008. The prices used in our external and internal reserve reports yield weighted average wellhead prices of $41.60 per barrel of oil and $5.12 per mcf of natural gas. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity hedges in place at December 31, 2008. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. Estimated future net revenue and the present value thereof differ from future net cash flows and the standardized measure thereof only because the former do not include the effects of estimated future income tax expenses ($3.8 billion as of December 31, 2008).

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 10 of the notes to our consolidated financial statements included in Item 8 of this report.

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As of December 31, 2008, our reserve estimates included 3.960 tcfe of reserves classified as proved undeveloped (PUD). Of this amount, approximately 31%, 18% and 16% (by volume) were initially classified as PUDs in 2008, 2007 and 2006, respectively, and the remaining 35% were initially classified as PUDs prior to 2006. Of our proved developed reserves, 1.222 tcfe are non-producing, which are primarily behind pipe zones in producing wells.

The future net revenue attributable to our estimated proved undeveloped reserves of $9.4 billion at December 31, 2008, and the $2.3 billion present value thereof, have been calculated assuming that we will expend approximately $6.4 billion to develop these reserves. Net of joint venture cost carries, we have projected to incur $925 million in 2009, $2.5 billion in 2010, $1.7 billion in 2011 and $1.3 billion in 2012 and beyond, although the amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, product prices and the availability of capital. 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 developmental drilling plans. 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.

The estimates of our proved reserves disclosed in this report were prepared by Chesapeake s internal staff based upon a review of production histories and other geologic, economic, ownership and engineering data we developed. The estimates were not based on any single significant assumption due to the diverse nature of the reserves and there is no significant concentration of proved reserve volume or value in any one well or field. Chesapeake is responsible for the adequacy and accuracy of the estimates. We engaged five third-party engineering firms to audit portions of our reserve estimates comprising approximately 76% of our estimated proved reserves (by volume) at year-end 2008. A reserve audit is not the same as a financial audit and a reserve audit is less rigorous in nature than a reserve report prepared by an independent petroleum engineering firm containing its own estimate of reserves. The portion of our estimated proved reserves audited by each of our third-party engineering firms as of December 31, 2008 is presented below.

	% Audited (by Volume)	Principal Properties Audited
Netherland, Sewell & Associates, Inc.	42%	Permian and Delaware Basins, Barnett Shale, portions of Ark-La-Tex, portions of Mid-Continent
Lee Keeling and Associates, Inc.	13%	Portions of Mid-Continent, portions of South Texas/ Texas Gulf Coast
Data and Consulting Services,		
Division of Schlumberger Technology Corporation	8%	Appalachian Basin
Ryder Scott Company, L.P.	8%	Portions of Mid-Continent, portions of South Texas/ Texas Gulf Coast
LaRoche Petroleum Consultants, Ltd.	5%	Portions of Mid-Continent, portions of Ark-La-Tex

Each of these third-party engineering firms opined that our estimates of proved reserves for those properties reviewed by such firm are, in the aggregate, reasonable, prepared in accordance with generally accepted petroleum engineering and evaluation principles, and conform to the SEC s definition of proved reserves. No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

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

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and participation agreements. The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for natural gas and oil production sold subsequent to December 31, 2008. 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 natural gas and oil 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 natural gas and oil that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate. A change in price of $0.10 per mcf for natural gas and $1.00 per barrel for oil would result in a change in the December 31, 2008 present value of estimated future net revenue of our proved reserves of approximately $400 million and $55 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, 2008, 2007 and 2006, and the changes in quantities and standardized measure of such reserves for each of the three years then ended, are shown in Note 10 of the notes to the consolidated financial statements included in Item 8 of this report.

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Exploration and Development, Acquisition and Divestiture Activities

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

	2008	December 31, 2007 ($ in millions)	2006
Development and exploration costs:			
Development drilling (a)	$ 5,185	$ 4,402	$ 2,772
Exploratory drilling	612	653	349
Geological and geophysical costs (b)	314	343	154
Asset retirement obligation and other	10	29	23
Total	6,121	5,427	3,298
Acquisition costs:			
Proved properties	355	671	1,175
Unproved properties (c)	8,129	2,465	3,473
Deferred income taxes	13	131	180
Total	8,497	3,267	4,828
Proceeds from divestitures:			
Proved properties	(2,433)	(1,142)	
Unproved properties	(5,302)		
Total	$ 6,883	$ 7,552	$ 8,126

(a) Includes capitalized internal cost of $326 million, $243 million and $147 million, respectively.
(b) Includes capitalized internal cost of $26 million, $19 million and $13 million, respectively.
(c) Includes costs to acquire new leasehold and related capitalized interest.

Our development costs included $1.5 billion, $1.5 billion and $1.2 billion in 2008, 2007 and 2006, respectively, related to properties carried as proved undeveloped locations in the prior year s reserve reports.

A summary of our exploration and development, acquisition and divestiture activities in 2008 by operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Acquisition of Unproved Properties	Acquisition of Proved Properties (a)	Sales of Unproved Properties	Sales of Proved Properties	Total
				($ in millions)				
Mid-Continent	2,096	714	$ 2,338	$ 652	$ 94	$ (2,458)	$ (2,322)	$ (1,696)
Barnett Shale	776	600	1,899	1,598	161			3,658
Appalachian Basin	161	137	379	897		(1,188)	(39)	49
Permian and Delaware Basins	165	95	841	325	11		(72)	1,105
Ark-La-Tex	413	136	429	4,630	8	(1,656)		3,411
South Texas and Texas Gulf Coast	65	51	235	27	94			356
Total	3,676	1,733	$ 6,121	$ 8,129	$ 368	$ (5,302)	$ (2,433)	$ 6,883

(a) Includes $13 million of deferred tax adjustments.

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Acreage

The following table sets forth as of December 31, 2008 the gross and net acres of both developed and undeveloped natural gas and oil 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 Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Mid-Continent	4,437,784	2,227,779	5,516,385	3,019,173	9,954,169	5,246,952
Barnett Shale	136,938	111,129	272,281	198,545	409,219	309,674
Appalachian Basin	574,287	542,448	5,536,546	4,338,124	6,110,833	4,880,572
Ark-La-Tex	296,349	178,458	1,784,321	1,122,717	2,080,670	1,301,175
South Texas and Texas Gulf Coast	317,649	185,166	222,562	151,664	540,211	336,830
Permian and Delaware Basins	424,279	234,333	3,795,251	2,550,334	4,219,530	2,784,667
Total	6,187,286	3,479,313	17,127,346	11,380,557	23,314,632	14,859,870

Marketing

Chesapeake Energy Marketing, Inc., one of our wholly-owned subsidiaries, provides natural gas and oil marketing services, including commodity price structuring, contract administration and nomination services for Chesapeake and its partners. We attempt to enhance the value of our natural gas production by aggregating natural gas to be sold to natural gas marketers and pipelines. This aggregation allows us to attract larger, more creditworthy customers that in turn assist in maximizing the prices received for our production.

Our oil production is generally sold under market sensitive or spot price contracts. The revenue we receive from the sale of natural gas liquids is included in oil sales. Our natural gas production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after transportation and processing of our natural gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. Under percentage-of-index contracts, the price per mmbtu we receive for our natural gas is tied to indexes published in *Inside FERC* or *Gas Daily*. Although exact percentages vary daily, as of February 2009, approximately 80% of our natural gas production was sold under short-term contracts at market-sensitive prices.

During 2008, sales to Eagle Energy Partners I, L.P. (Eagle) of $1.3 billion accounted for 12% of our total revenues (excluding gains (losses) on derivatives). In 2007, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $124 million and a gain of $83 million. Management believes that the loss of this customer would not have a material adverse effect on our results of operations or our financial position. No other customer accounted for more than 10% of total revenues (excluding gains (losses) on derivatives) in 2008.

Our marketing activities constitute a reportable segment under SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information*. See Note 15 of the notes to our consolidated financial statements in Item 8.

Midstream Operations

Chesapeake invests in gathering and processing facilities to complement our natural gas and oil operations in regions where we have significant production. By doing so, we are better able to manage the value received for and the costs of, gathering, treating and processing natural gas. We own and operate gathering systems in 15

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states throughout the primary areas of Chesapeake s natural gas and oil producing regions. These systems are designed primarily to gather company production for delivery into major intrastate or interstate pipelines and are comprised of approximately 9,800 miles of gathering lines, treating facilities and processing facilities which provide service to approximately 12,500 wells.

We recently transferred substantially all of our midstream assets outside of Appalachia to a group of existing and newly formed wholly-owned subsidiaries, which we refer to as our midstream subsidiaries . The midstream subsidiaries, their parent, Chesapeake Midstream Partners, L.P. (CMP), and its principal operating subsidiary, Chesapeake Midstream Operating, L.L.C. (CMO), were each designated as unrestricted subsidiaries under Chesapeake s indentures and revolving bank credit facility and were released from their guarantee obligations under Chesapeake s indentures, revolving bank credit facility and secured hedging facilities. In October 2008, CMP and CMO entered into a $460 million revolving bank credit facility. They are using borrowings under the facility to fund capital expenditures associated with building additional natural gas gathering and other systems associated with Chesapeake s drilling program and for general corporate purposes related to its midstream operations.

We have plans to sell either a minority interest in our midstream natural gas business or specific midstream assets. Proceeds from a midstream transaction would be used to fund a portion of the costs associated with building the midstream infrastructure in various shale plays, primarily in the Haynesville, Marcellus and Fayetteville shale plays.

Drilling

Securing available rigs is an integral part of the exploration process and therefore owning our own drilling company is a strategic advantage for Chesapeake. In 2001, Chesapeake formed its 100% owned drilling rig subsidiary, Nomac Drilling Corporation, with an investment of $26 million to build and refurbish five drilling rigs. As of December 31, 2008, Chesapeake had invested approximately $782 million to build or acquire 84 drilling rigs and to initiate the construction of 23 additional rigs. In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 83 rigs for $677 million and subsequently leased back the rigs through 2018. The drilling rigs have depth ratings between 3,000 and 25,000 feet and range in drilling horsepower from 525 to 2,000. These drilling rigs are currently operating in Oklahoma, Texas, Arkansas, Louisiana and Appalachia. Chesapeake is the fourth largest drilling rig contractor in the U.S.

Trucking

In 2006, Chesapeake expanded its service operations by acquiring two privately-owned oilfield trucking service companies. We now own one of the largest oilfield and heavy haul transportation companies in the industry. Our trucking business is utilized primarily to transport drilling rigs for both Chesapeake and third parties. Through this ownership, we are better able to manage the movement of our rigs. As of December 31, 2008, our fleet included 250 trucks and 15 cranes, which mainly service the Mid-Continent, Barnett Shale and Appalachian regions.

Compression

During the past few years Chesapeake has expanded its compression business. Our wholly-owned subsidiary, MidCon Compression, L.L.C., operates wellhead and system compressors to facilitate the transportation of our natural gas production. In a series of transactions in 2007 and 2008, MidCon sold a significant portion of its compressor fleet, consisting of 1,443 compressors, for $303 million and entered into a master lease agreement. These transactions were recorded as sales and operating leasebacks. Over the next two years, 625 new compressors are on order for approximately $240 million, and we intend to simultaneously enter into sale/leaseback transactions with financial counterparties as the compressors are delivered, if acceptable leasing arrangements are available to us.

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Seasonal Nature of Business

Generally, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers can lessen or intensify this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can lessen seasonal demand fluctuations. World weather and resultant prices for LNG can also affect deliveries of competing LNG into this country from abroad, affecting the price of domestically produced natural gas.

Competition

We compete with both major integrated and other independent natural gas and oil companies in acquiring desirable leasehold acreage, producing properties and the equipment and expertise necessary to explore, develop and operate our properties and market our production. Some of our competitors may have larger financial and other resources than ours. The natural gas and oil industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported LNG. Competitive conditions may be affected by future legislation and regulations as the U.S. develops new energy and climate-related policies. In addition, some of our larger competitors may have a competitive advantage when responding to factors that affect demand for natural gas and oil production, such as changing prices, domestic and foreign political conditions, weather conditions, the price and availability of alternative fuels, the proximity and capacity of gas pipelines and other transportation facilities, and overall economic conditions. We believe that our technological expertise, our exploration, land, drilling and production capabilities and the experience of our management generally enable us to compete effectively.

Hedging Activities

We utilize hedging strategies to hedge the price of a portion of our future natural gas and oil 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. natural gas and oil industry is regulated at the federal, state and local levels, and some of the laws, rules and regulations that govern our operations carry substantial penalties for noncompliance. These regulatory burdens increase our cost of doing business and, consequently, affect our profitability.

Regulation of Natural Gas and Oil Operations. Our exploration and production operations are subject to various types of regulation at the U.S. federal, state and local levels. Such regulation includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Very few of our natural gas and oil leases are located on federal lands. 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 generated 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 that may be drilled in a particular area) and the unitization or pooling of natural gas and oil properties. In this regard, some states, such as Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas 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 natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amount of natural gas and oil we can produce and to limit the number of wells and the locations at which we can drill.

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

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

Environmental, Health and Safety Regulation. The business operations of the company and its ownership and operation of natural gas and oil interests are subject to various federal, state and local environmental, health and safety laws and regulations pertaining to the release, emission or discharge of materials into the environment, the generation, storage, transportation, handling and disposal of materials (including solid and hazardous wastes), the safety of employees, or otherwise relating to pollution, preservation, remediation or protection of human health and safety, natural resources, wildlife or the environment. We must take into account the cost of complying with environmental regulations in planning, designing, constructing, drilling, operating and abandoning wells and related surface facilities. In most instances, the regulatory frameworks relate to the handling of drilling and production materials, the disposal of drilling and production wastes, and the protection of water and air. In addition, our operations may require us to obtain permits for, among other things,

- air emissions,
- the construction and operation of underground injection wells to dispose of produced saltwater and other non-hazardous oilfield wastes, and
- the construction and operation of surface pits to contain drilling muds and other non-hazardous fluids associated with drilling operations.

Under federal, state and local 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 at contaminated areas, or to perform remedial well plugging operations or response actions to reduce the risk of future contamination. Federal laws, including the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and analogous state laws impose joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered responsible for response actions to address the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and persons that disposed of or arranged for the disposal of hazardous substances at the site. 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 actions. Furthermore, certain wastes generated by our natural gas and oil 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.

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Vast quantities of natural gas deposits exist in deep shale formations. It is customary in our industry to recover natural gas from these deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is the process of creating artificial cracks, or fractures, in shale formations deep underground where water, sand and other additives are pumped under high pressure into a shale gas formation. These deep shale gas formations are generally geologically separated and isolated from any fresh ground water supplies by thousands of feet of protective rock layers. Our well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into overlying aquifers. Legislative and regulatory efforts at the federal level and in some states have been made to render permitting and compliance requirements more stringent for hydraulic fracturing. Such efforts could have an adverse effect on our operations.

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

We have made and will continue to make expenditures to comply with environmental, health and safety regulations and requirements. These are necessary business costs in the natural gas and oil industry. Although we are not fully insured against all environmental, health and safety risks, and our insurance does not cover any penalties or fines that may be issued by a governmental authority, 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, health and safety 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 material compliance with existing environmental, health and safety 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 business, financial position and results of operations.

Income Taxes

Chesapeake recorded income tax expense of $463 million in 2008 compared to income tax expense of $890 million in 2007 and $1.252 billion in 2006. Of the income tax expense recorded in 2008, $423 million is reflected as current income tax expense and $40 million is reflected as deferred income tax expense. The divestitures that closed during 2008 are projected to generate sufficient taxable income for the year to exhaust all our non-limited NOLs and result in a current tax liability for the tax year ended December 31, 2008. Of the $427 million decrease in 2008, $439 million was the result of the decrease in net income before taxes which was offset by $12 million as the result of an increase in the effective tax rate. Our effective income tax rate was 39% in 2008 compared to 38% in 2007 and 38.5% in 2006. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences between our accounting for certain revenue or expense items and their corresponding treatment for income tax purposes. We expect our effective income tax rate to be 39% in 2009.

At December 31, 2008, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $12 million. We also had approximately $3 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income. The NOL carryforwards expire from 2019 through 2026. The value of the remaining carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs.

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

In the event of an ownership change (as defined for income tax purposes), Section 382 of the Code imposes an annual limitation on the amount of a corporation s taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Certain NOLs acquired through various acquisitions are also subject to limitations. The following table summarizes our net operating losses as of December 31, 2008 and any related limitations:

	Net Operating Losses		
	Total	Limited	Annual Limitation
		($ in millions)	
Net operating loss	$ 12	$ 12	$ 7
AMT net operating loss	$ 3	$ 3	$ 1

As of December 31, 2008, we do not believe that an ownership change has occurred. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs. Following an ownership change, the amount of Chesapeake s NOLs available for use each year will depend upon future events that cannot currently be predicted and upon interpretation of complex rules under Treasury regulations.

If less than the full amount of the annual limitation is utilized in any given year, the unused portion may be carried forward and may be used in addition to successive years annual limitation.

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

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 became effective for fiscal years beginning after December 15, 2006.

Chesapeake adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, Chesapeake recognized a $7 million liability for accrued interest associated with uncertain tax positions which was accounted for as a reduction in the January 1, 2007 balance of retained earnings, net of tax. At the date of adoption and at December 31, 2007, we had approximately $142 million and $133 million, respectively, of unrecognized tax benefits related to alternative minimum tax (AMT) associated with uncertain tax positions. As of December 31, 2008, the amount of unrecognized tax benefits related to regular tax liabilities and AMT associated with uncertain tax positions was $60 million. Of this amount, $48 million is related to regular tax liabilities and $12 million is related to AMT. These unrecognized tax benefits are associated with temporary differences. If these unrecognized tax benefits are disallowed and we are required to pay additional taxes, the reversal of the temporary differences associated with the regular tax liabilities will increase our tax basis which will increase our future tax deductions. Any AMT payments can be utilized as credits against future regular tax liabilities. The uncertain tax positions identified would not have a material effect on the effective tax rate. At December 31, 2008, we had an accrued liability of $3 million for interest related to these uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

Chesapeake files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. With few exceptions, Chesapeake is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years prior to 2005. The Internal Revenue Service (IRS) completed an examination of Chesapeake s U.S. income tax returns for 2005 and 2006 in December 2008. This examination resulted in additional AMT liabilities of $1 million. These AMT liabilities will be utilized as credits against current regular tax liabilities. The adjustments in the examination did not result in a material change to our financial position, results of operations or cash flows.

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 natural gas and oil 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 natural gas and oil industry. Nevertheless, we are involved in title disputes from time to time which result in litigation.

Operating Hazards and Insurance

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

Chesapeake maintains a $50 million control of well 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 $350 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. 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 we continue to construct additional buildings in Oklahoma City. We also own or lease various field or administrative offices in the following locations:

Arkansas: Searcy and Little Rock

Illinois: Chicago

Kansas: Garden City

Kentucky: Gray, Elkhorn City, Hueysville, Debord and Langley

Louisiana: Cheneyville, Goldonna and Shreveport

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New Mexico: Carlsbad, Eunice, Hobbs and Lovington

New York: Horseheads

Oklahoma: Arkoma, Billings, El Reno, Elk City, Enid, Forgan, Hartshorne, Hinton, Kingfisher, Lindsay, Mayfield, Oklahoma City, Waynoka, Weatherford, Wilburton and Woodward

Pennsylvania: Mt. Morris, Mansfield and Towanda

Tennessee: Egan

Texas: Alvarado, Borger, Bryan, Cleburne, College Station, Dumas, Fort Worth, Garrison, Marshall, Midland, Ozona, Palestine, Pecos, Tyler, Victoria and Zapata

West Virginia: Branchland, Buckhannon, Chapmanville, Charleston, Cedar Grove, Clendenin, Hamlin, Jane Lew, Kermit, Shrewsbury, Tad and Teays Valley

Employees

Chesapeake had approximately 7,600 employees as of December 31, 2008, which includes approximately 2,750 employed by our service operations companies. As a result of our acquisition of Columbia Natural Resources, LLC in November 2005, we assumed a collective bargaining agreement with the United Steel Workers of America (USWA) which expired effective December 1, 2006, covering approximately 139 of our field employees in West Virginia and Kentucky. We continued to operate under the terms of the collective bargaining agreement while negotiating with the USWA. Contract negotiations began in October 2006 and have been mediated by the Federal Mediation and Conciliation Service. On May 4, 2007, we presented the USWA leadership our last, best and final offer . On December 7, 2007, the USWA membership voted to reject our offer. The company declared an impasse and, effective February 1, 2008, we implemented the terms of our offer with certain minor clarifications. Subsequently, the union filed three separate unfair labor practice charges. One charge was dismissed by the National Labor Relations Board and two charges were settled by mutual agreement. There have been no strikes, work stoppages or slowdowns since the expiration of the contract, although no assurances can be given that such actions will not occur.

Glossary of Natural Gas and Oil Terms

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent.

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

Bbtu. One billion British thermal units.

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. A natural gas and oil well which produces natural gas and oil in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Conventional Reserves. Natural gas and oil occurring as discrete accumulations in structural and stratigraphic traps.

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

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

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

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

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

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

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

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

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

Infill Drilling. Drilling wells between established producing wells on a lease; a drilling program to reduce the spacing between wells in order to increase production and/or recovery of in-place hydrocarbons from the lease.

Karst. An area of irregular limestone in which erosion has produced fissures, sinkholes, underground streams and caverns.

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

Mbtu. One thousand btus.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of natural gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of natural gas equivalent.

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

NYMEX. New York Mercantile Exchange.

Play. A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential natural gas and oil reserves.

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

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

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

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

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

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

Reserve Replacement. Calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries and other additions and acquisitions) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table located in Note 10 of the notes to our consolidated financial statements. In calculating reserve replacement, we do not use unproved reserve quantities or proved reserve additions attributable to less than wholly-owned consolidated entities or investments accounted for using the equity method. Management uses the reserve replacement ratio as an indicator of the company s ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

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

Seismic. An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures).

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

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

Tcf. One trillion cubic feet.

Tcfe. One trillion cubic feet of natural gas equivalent.

Unconventional Reserves. Natural gas and oil occurring in regionally pervasive accumulations with low matrix permeability and close association with source rocks.

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 natural gas and oil regardless of whether such acreage contains proved reserves.

Unproved Properties. Properties with no proved reserves.

VPP. A volumetric production payment represents an obligation of the seller of a property to deliver a specific volume of production, free and clear of all costs, to the purchaser of the property.

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*

Natural gas and oil 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 natural gas and oil 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, falling prices may result in ceiling test write-downs of our natural gas and oil properties, as described below in the risk factor Price declines during 2008 resulted in a write-down of our asset carrying values and future price declines could result in additional write-downs in the future .

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

- worldwide and domestic supplies of natural gas and oil, including U.S. inventories of natural gas and oil reserves;
- 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 natural gas and oil price movements with any certainty. Declines in natural gas and oil prices not only reduce revenue, but also reduce the amount of natural gas and oil 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, natural gas and oil prices do not necessarily move in tandem. Because approximately 94% of our reserves at December 31, 2008 were natural gas reserves, we are more affected by movements in natural gas prices.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2008, we had long-term indebtedness of approximately $14.184 billion, with $3.474 billion of outstanding borrowings drawn under our revolving bank credit facility and $460 million of outstanding borrowings drawn under our midstream revolving bank credit facility. Our net indebtedness represented 43% of our total book capitalization at December 31, 2008. Following the February 2009 issuance of $1.425 billion of 9.5% Senior Notes due 2015, we had as of February 26, 2009 $1.630 billion outstanding under our revolving bank credit facility and $424 million outstanding under our midstream revolving bank credit facility.

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

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

We may incur additional debt, including secured indebtedness, or issue additional series of preferred stock in order to develop our properties and make future acquisitions. 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, natural gas and oil prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. 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, the number of shares of capital stock we have authorized, unissued and unreserved and our performance at the time we need capital.

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Chesapeake Midstream Operating s midstream revolving bank credit facility contains a covenant restricting Chesapeake Midstream Partners from paying dividends or distributions to Chesapeake.

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.

The current financial crisis may have impacts on our business and financial condition that we cannot predict.

The continued credit crisis and related turmoil in the global economic financial systems may have an impact on our business and our financial condition, and we may face challenges if conditions in the economy and financial markets do not improve. Although we believe we have developed an operating and capital budget for 2009 and 2010 that will allow us to fund our business with internally generated cash flow, our cash flow from operations, our revolving bank credit facility and cash on hand historically have not been sufficient to fund all of our expenditures, and we have relied on the capital markets and asset monetization transactions to provide us with additional capital. Our ability to access the capital markets has been restricted from time to time as a result of this crisis and may be restricted at a time when we would like, or need, to raise capital. The financial crisis may also limit the number of participants in our proposed asset monetization transactions or reduce the values we are able to realize in those transactions, making them uneconomic or harder or impossible to consummate. The economic situation could also adversely affect the collectability of our trade receivables and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. If our joint venture partners do not meet their obligations to fund a portion of our drilling costs in the Haynesville, Fayetteville or Marcellus Shale plays as agreed under our joint venture arrangements, or if our Haynesville joint venture partner, Plains Exploration & Production Company, exercises its option in June 2010 to reduce its drilling cost carry obligation by $800 million as described in Item 1 of this report under Operating Areas , we may be required to fund these expenditures from other sources or reduce our drilling activities. Additionally, the current economic situation could lead to reduced demand for natural gas and oil or lower prices for natural gas and oil or both, over the long term, which would have a negative impact on our revenues.

Price declines at the end of 2008 resulted in a write-down of our asset carrying values and further price declines could result in additional write-downs in the future.

We utilize the full-cost method of accounting for costs related to our natural gas and oil 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 natural gas and oil 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 natural gas and oil at that date, adjusted for the impact of derivatives accounted for as cash flow hedges.

Natural gas and oil prices declined substantially throughout the second half of 2008 and were $5.71 per mcf and $44.61 per barrel on December 31, 2008. Our financial statements as of and for the year ended December 31, 2008 reflect an impairment of approximately $1.7 billion, net of income tax, of our natural gas and oil properties. We also had an after-tax non-cash impairment charge to certain investments and fixed assets of approximately $128 million for the 2008 fourth quarter as a result of lower asset valuation estimates.

Commodity prices in early 2009 have continued to trend lower. This and other factors could cause us to write down our natural gas and oil properties or other assets in the future and incur a non-cash charge against future earnings.

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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. Beginning in late 2007, we have also engaged in significant asset monetization transactions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of natural gas and oil, our success in developing and producing new reserves, the orderly functioning of credit and capital markets and our ability to complete additional planned asset monetization transactions. If revenues were to decrease as a result of lower natural gas and oil 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 natural gas and oil 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 33% of our total estimated proved reserves (by volume) at December 31, 2008 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates reflect that our production rate on producing properties will decline approximately 29% from 2009 to 2010. Thus, our future natural gas and oil 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 natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating natural gas and oil 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, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil 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 natural gas and oil 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, 2008, approximately 33% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. These reserve estimates include the assumption that we will make significant capital expenditures to develop the reserves, including approximately $925 million in 2009. 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 natural gas and oil 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, 2008 present value is based on weighted average natural gas and oil wellhead prices of $5.12 per mcf of natural gas and $41.60 per barrel of oil. 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 natural gas and oil 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 natural gas and oil 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 natural gas and oil industry in general will affect the accuracy of the 10% discount factor.

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

- increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment;
- unexpected drilling conditions;
- restricted access to land for drilling or laying pipeline;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions; and
- compliance with environmental and other governmental requirements.

Drilling results in our newer shale plays, primarily the Haynesville and Marcellus Shales, may be more uncertain than in shale plays that are more developed and have longer established production histories, such as the Barnett and Fayetteville Shales. Our experience with horizontal drilling in the Haynesville and Marcellus Shales, as well as the industry s drilling and production history, is more limited than in the Barnett and Fayetteville Shale plays. Completion techniques that have proven to be successful in other shale formations to maximize recoveries are being used in the early development of the Haynesville and Marcellus Shales; however, we can provide no assurance of the ultimate success of these drilling and completion techniques.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2008, we had leases on approximately 0.46 million and 1.25 million net acres, respectively, in the Haynesville and Marcellus Shale areas. A sizeable portion of this acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various

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factors, including drilling results, natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

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

In order to manage our exposure to price volatility in marketing our natural gas and oil, we enter into natural gas and oil price risk management arrangements for a portion of our expected production. Commodity price hedging may limit the prices we actually realize and therefore reduce natural gas and oil revenues in the future. Our commodity hedging activities will impact our earnings in various ways, including recognition of certain mark-to-market gains and losses on derivative instruments. The fair value of our natural gas and oil derivative instruments can fluctuate significantly between periods. In addition, our commodity price risk management transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

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

Acquisitions may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities and market forces may change expected economics of acquisitions.

Our growth during the past few years is due in large part to acquisitions of exploration and production companies, producing properties and undeveloped leasehold. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future natural gas and oil prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire natural gas and oil properties may exceed the value we realize. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties. When we make entity acquisitions, we may have transferee liability that is not fully indemnified. The company currently is a defendant in cases involving acquired companies where we may have no, or only limited, indemnification rights. In any such actions we could incur significant liability.

Finally, market forces beyond our control may change the expected economics of acquisitions. Due to the current financial crisis, decreases in natural gas prices and concerns about an oversupply of natural gas in the U.S., for example, market prices for undeveloped natural gas leasehold declined considerably during the second

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half of 2008. As a result, we have not closed on pending transactions with several significant Haynesville Shale mineral or leasehold owners and instead are seeking to acquire their interests at reduced prices. We have reached agreement with some of these owners and are still negotiating with others, including owners that have filed lawsuits against us alleging enforceable contracts providing for lease bonus payments above current market prices.

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

Our revolving bank credit facility limits our borrowings to the lesser of the borrowing base and the total commitments. Currently both are $3.5 billion, although one lender, Lehman Brothers Commercial Bank, has not funded its share (2.1%) of our borrowings under the facility beginning in the third quarter of 2008, and we do not expect that it would fund any future borrowings. The borrowing base is determined periodically at the discretion of the banks and is based in part on natural gas and oil prices. Additionally, some of our indentures contain covenants limiting our ability to incur indebtedness in addition to that incurred under our revolving bank credit facility. These indentures limit our ability to incur additional indebtedness unless we meet one of two alternative tests. The first alternative is based on our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved natural gas and oil 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 (as defined in the relevant indentures) over a trailing twelve-month period. Currently, we are permitted to incur additional indebtedness under both debt incurrence tests. Lower natural gas and oil 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.

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

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

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

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

In addition, studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases, may be impacting the Earth s climate. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. Congress and various states have been evaluating climate-related legislation and other regulatory initiatives that would restrict emissions of greenhouse gases in areas in which we conduct business. Such restrictions may have an effect on demand for our products, particularly because natural gas is viewed by many as a readily available replacement for more carbon intensive sources of energy. Likewise, such restrictions may result in additional compliance obligations with respect to the release, capture and use of carbon dioxide that could have an adverse effect on our operations.

It is customary in our industry to use hydraulic fracturing a process that creates a fracture extending from the well bore in a rock formation to enable gas or oil to move more easily through the rock pores to a production well. Fractures are typically created through the injection of water and chemicals into the rock formation. Legislative and regulatory efforts at the federal level and in some states have been made to render permitting and compliance requirements more stringent for hydraulic fracturing. Such efforts could have an adverse effect on our operations.

Our ability to sell natural gas and/or receive market prices for our natural gas may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.

If drilling in the Haynesville and Marcellus Shales continues to be successful, the amount of natural gas being produced by us and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for the Haynesville and Marcellus Shale areas may not occur for lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas production at significantly lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations.

A portion of our natural gas and oil production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

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

None.

ITEM 2. ***Properties***

Information regarding our properties is included in Item 1 and in Note 10 of the notes to our consolidated financial statements included in Item 8 of this report.

ITEM 3. ***Legal Proceedings***

Litigation

We are involved in various disputes incidental to our business operations, including claims from royalty owners regarding volume measurements, post-production costs and prices for royalty calculations. In *Tawney, et al. v. Columbia Natural Resources, Inc.,* Chesapeake s wholly-owned subsidiary Chesapeake Appalachia, L.L.C., formerly known as Columbia Natural Resources, LLC (CNR), is a defendant in a class action lawsuit filed in

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2003 in the Circuit Court for Roane County, West Virginia by royalty owners. The plaintiffs allege that CNR underpaid royalties by improperly deducting post-production costs, failing to pay royalty on total volumes of natural gas produced and not paying a fair value for the natural gas produced from their leases. The plaintiff class consists of West Virginia royalty owners receiving royalties after July 31, 1990 from CNR. Chesapeake acquired CNR in November 2005, and its seller acquired CNR in 2003 from NiSource Inc. NiSource, a co-defendant in the case, indemnified Chesapeake against underpayment claims based on the use of fixed prices for natural gas production sold under certain forward sale contracts and other claims with respect to CNR s operations prior to September 2003.

On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of $404 million, consisting of $134 million in compensatory damages and $270 million in punitive damages. The jury found fraudulent conduct by the defendants with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions. The defendants appealed the judgment and on May 22, 2008, the West Virginia Supreme Court of Appeals refused to hear the appeal. On October 22, 2008, the parties in the *Tawney* matter entered into a settlement agreement providing for the establishment of a settlement fund of $380 million. The Circuit Court for Roane County, West Virginia approved the settlement following a fairness hearing on November 22, 2008, and entered an order to discharge the judgment on January 21, 2009. Chesapeake s share of the settlement fund was approximately $41 million, which amount had previously been fully reserved. The Circuit Court retains continuing jurisdiction over the case during the claims administration process in which the settlement amount is distributed to the members of the plaintiff class.

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

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

Not applicable.

PART II

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

Price Range of Common Stock

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

	Common Stock	
	High	**Low**
Year ended December 31, 2008:		
Fourth Quarter	$ 35.46	$ 9.84
Third Quarter	74.00	31.15
Second Quarter	68.10	45.25
First Quarter	49.87	34.42
Year ended December 31, 2007:		
Fourth Quarter	$ 41.19	$ 34.90
Third Quarter	37.55	31.38
Second Quarter	37.75	30.88
First Quarter	31.83	27.27

At February 26, 2009, there were approximately 2,025 holders of record of our common stock and 455,500 approximately beneficial owners.

Dividends

The following table sets forth the amount of dividends per share declared on Chesapeake common stock during 2008 and 2007:

	2008	**2007**
Fourth Quarter	$ 0.075	$ 0.0675
Third Quarter	0.075	0.0675
Second Quarter	0.075	0.0675
First Quarter	0.0675	0.06

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

In addition, our revolving bank credit facility and the indentures governing certain of our outstanding senior notes contain restrictions on our ability to declare and pay cash dividends. Under the revolving bank credit facility and these indentures, we may not pay any cash dividends on our common or preferred stock if an event of default has occurred. These indentures further restrict cash dividends if we have not met one of the two debt incurrence tests set forth 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, 2008, our coverage ratio for purposes of the debt incurrence test under the relevant indentures was 8.7 to 1, compared to a minimum of 2.25 to 1 required in such indentures. Our adjusted consolidated net tangible assets exceeded 200% of our total indebtedness, as required by the second debt incurrence test in these indentures, by approximately $1.0 billion.

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The certificates of designation for our 5.00% Cumulative Convertible Preferred Stock (Series 2005), our 4.50% Cumulative Convertible Preferred Stock, our 5.00% Cumulative Convertible Preferred Stock (Series 2005B), our 4.125% Cumulative Convertible Preferred Stock and our 6.25% Mandatory Convertible Preferred Stock prohibit payment of cash dividends on our common stock unless we have declared and paid (or set apart for payment) full accumulated dividends on such series of our preferred stock.

Purchases of Common Stock

The following table presents information about repurchases of our common stock during the three months ended December 31, 2008:

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, 2008 through October 31, 2008	24,174	$ 22.388		
November 1, 2008 through November 30, 2008	15,976	$ 20.658		
December 1, 2008 through December 31, 2008	5,385	$ 15.829		
Total	45,535	$ 21.005		

(a) Includes the deemed surrender to the company of 5,868 shares of common stock to pay the exercise price in connection with the exercise of employee stock options and the surrender to the company of 39,667 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) plan and deferred compensation plan using Chesapeake common stock which is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of the company contributions. There are no other repurchase plans or programs currently authorized by the Board of Directors.

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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, 2008, 2007, 2006, 2005 and 2004. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. Changes in annual average natural gas and oil prices and increased production from drilling and acquisition activity in recent years have impacted comparability between years. See Note 10 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, 2008	2007	2006	2005	2004
	($ in millions, except per share data)				
Statement of Operations Data:					
Revenues:					
Natural gas and oil sales	$ 7,858	$ 5,624	$ 5,619	$ 3,273	$ 1,936
Natural gas and oil marketing sales	3,598	2,040	1,577	1,392	773
Service operations revenue	173	136	130		
Total revenues	11,629	7,800	7,326	4,665	2,709
Operating costs:					
Production expenses	889	640	490	317	205
Production taxes	284	216	176	208	104
General and administrative expenses	377	243	139	64	37
Natural gas and oil marketing expenses	3,505	1,969	1,522	1,358	755
Service operations expense	143	94	68		
Natural gas and oil depreciation, depletion and amortization	1,970	1,835	1,359	894	582
Depreciation and amortization of other assets	177	154	104	51	29
Impairment of natural gas and oil properties and other fixed assets	2,830				
Employee retirement expense			55		
Provision for legal settlements					5
Total operating costs	10,175	5,151	3,913	2,892	1,717
Income from operations	1,454	2,649	3,413	1,773	992
Other income (expense):					
Interest and other income	(11)	15	26	10	5
Interest expense	(314)	(406)	(301)	(220)	(167)
Gain (loss) on repurchases or exchanges of Chesapeake debt	237			(70)	(25)
Impairment of investments	(180)				
Gain on sale of investments		83	117		
Total other income (expense)	(268)	(308)	(158)	(280)	(187)
Income before income taxes and cumulative effect of accounting change	1,186	2,341	3,255	1,493	805
Income tax expense:					
Current	423	29	5		
Deferred	40	861	1,247	545	290
Total income tax expense	463	890	1,252	545	290
Net Income	723	1,451	2,003	948	515
Preferred stock dividends	(33)	(94)	(89)	(42)	(40)
Loss on conversion/exchange of preferred stock	(67)	(128)	(10)	(26)	(36)
Net income available to common shareholders	$ 623	$ 1,229	$ 1,904	$ 880	$ 439

Earnings per common share:					
Basic	$ 1.16	$ 2.69	$ 4.78	$ 2.73	$ 1.73
Assuming dilution	$ 1.14	$ 2.62	$ 4.35	$ 2.51	$ 1.53
Cash dividends declared per common share	$ 0.2925	$ 0.2625	$ 0.23	$ 0.195	$ 0.17
Cash Flow Data:					
Cash provided by operating activities	$ 5,236	$ 4,932	$ 4,843	$ 2,407	$ 1,432
Cash used in investing activities	9,844	7,922	8,942	6,921	3,381
Cash provided by financing activities	6,356	2,988	4,042	4,567	1,915
Balance Sheet Data (at end of period):					
Total assets	$ 38,444	$ 30,734	$ 24,417	$ 16,118	$ 8,245
Long-term debt, net of current maturities	14,184	10,950	7,376	5,490	3,075
Stockholders equity	16,297	12,130	11,251	6,174	3,163

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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, natural gas and oil sales, average sales prices received, other operating income and expenses for the periods indicated:

	Years Ended December 31, 2008	2007	2006
Net Production:			
Natural gas (mmcf)	775,424	654,969	526,459
Oil (mbbls)	11,220	9,882	8,654
Natural gas equivalent (mmcfe)	842,744	714,261	578,383
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 6,003	$ 4,117	$ 3,343
Natural gas derivatives realized gains (losses)	267	1,214	1,269
Natural gas derivatives unrealized gains (losses)	521	(139)	467
Total natural gas sales	6,791	5,192	5,079
Oil sales	1,066	678	527
Oil derivatives realized gains (losses)	(275)	(11)	(15)
Oil derivatives unrealized gains (losses)	276	(235)	28
Total oil sales	1,067	432	540
Total natural gas and oil sales	$ 7,858	$ 5,624	$ 5,619
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 7.74	$ 6.29	$ 6.35
Oil ($ per bbl)	$ 95.04	$ 68.64	$ 60.86
Natural gas equivalent ($ per mcfe)	$ 8.39	$ 6.71	$ 6.69
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 8.09	$ 8.14	$ 8.76
Oil ($ per bbl)	$ 70.48	$ 67.50	$ 59.14
Natural gas equivalent ($ per mcfe)	$ 8.38	$ 8.40	$ 8.86
Other Operating Income (a) ($ in millions):			
Natural gas and oil marketing	$ 93	$ 71	$ 55
Service operations	$ 30	$ 42	$ 62
Other Operating Income (a) ($ per mcfe):			
Natural gas and oil marketing	$ 0.11	$ 0.10	$ 0.09
Service operations	$ 0.04	$ 0.06	$ 0.11
Expenses ($ per mcfe):			
Production expenses	$ 1.05	$ 0.90	$ 0.85
Production taxes	$ 0.34	$ 0.30	$ 0.31
General and administrative expenses	$ 0.45	$ 0.34	$ 0.24
Natural gas and oil depreciation, depletion and amortization	$ 2.34	$ 2.57	$ 2.35
Depreciation and amortization of other assets	$ 0.21	$ 0.22	$ 0.18
Interest expense (b)	$ 0.27	$ 0.51	$ 0.52
Interest Expense ($ in millions):			
Interest expense	$ 235	$ 365	$ 301
Interest rate derivatives realized (gains) losses	(6)	1	2
Interest rate derivatives unrealized (gains) losses	85	40	(2)
Total interest expense	$ 314	$ 406	$ 301

Net Wells Drilled	1,733	1,919	1,449
Net Producing Wells as of the End of Period	22,813	21,404	19,079

(a) Includes revenue and operating costs and excludes depreciation and amortization of other assets.
(b) Includes the effects of realized gains (losses) from interest rate derivatives, but excludes the effects of unrealized gains (losses) and is net of amounts capitalized.

We manage our business as three separate operational segments: exploration and production; marketing; and service operations, which is comprised of our wholly-owned drilling and trucking operations. We refer you to Note 14 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 2008, 2007 and 2006 and our assets as of December 31, 2008, 2007 and 2006.

Executive Summary

We are the largest independent producer of natural gas in the United States. We own interests in approximately 41,200 producing oil and natural gas wells that are currently producing approximately 2.3 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S., primarily in the Big 4 natural gas shale plays: the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville Shale in the Ark-La-Tex area of northwestern Louisiana and East Texas, the Fayetteville Shale in the Arkoma Basin of central Arkansas and the Marcellus Shale in the northern Appalachian Basin of West Virginia, Pennsylvania and New York. We also have substantial operations in various other plays, both conventional and unconventional, in the Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the United States.

During 2008, Chesapeake continued the industry s most active drilling program drilling 1,819 gross (1,491 net) operated wells and participating in another 1,857 gross (242 net) wells operated by other companies. The company s drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during 2008, we invested $5.043 billion in operated wells (using an average of 145 operated rigs) and $754 million in non-operated wells (using an average of 110 non-operated rigs) for total drilling, completing and equipping costs of $5.797 billion.

Chesapeake began 2008 with estimated proved reserves of 10.879 tcfe and ended the year with 12.051 tcfe, an increase of 1.172 tcfe, or 11%. During 2008, we replaced 843 bcfe of production with an internally estimated 2.015 tcfe of new proved reserves, for a reserve replacement rate of 239%. Reserve replacement through the drillbit was 2.545 tcfe, or 302% of production, including 1.248 tcfe of positive performance revisions and 298 bcfe of negative revisions resulting from natural gas and oil price decreases between December 31, 2007 and December 31, 2008. Reserve replacement through the acquisition of proved reserves was 172 bcfe. During 2008, we divested 702 bcfe of estimated proved reserves. Our annual decline rate on producing properties is projected to be 29% from 2009 to 2010, 18% from 2010 to 2011, 14% from 2011 to 2012, 11% from 2012 to 2013 and 9% from 2013 to 2014. Our percentage of proved undeveloped reserve additions to total proved reserve additions was approximately 2% in 2008, 29% in 2007 and 38% in 2006. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2008 will begin producing within the next three to five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within one year.

Since 2000, Chesapeake has invested $12.6 billion in new leasehold (net of divestitures) and 3-D seismic acquisitions and now owns the largest combined inventories of onshore leasehold (15 million net acres) and 3-D seismic (22 million acres) in the U.S. On this leasehold, the company has approximately 36,000 net drillsites representing more than a 10-year inventory of drilling projects.

Business Strategy

Our exploration, development and acquisition activities require us to make substantial operating and capital expenditures. Through the middle of 2008, we increased our capital expenditure budget for 2008 and 2009 several times in response to higher leasehold acquisition costs and in order to accelerate leasehold acquisition and drilling in the Haynesville Shale and other plays. During the second half of 2008, in response to a significant decrease in natural gas prices, deteriorating global economic conditions and outlook and concerns about a

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potential oversupply of natural gas in the U.S. market, we significantly reduced our planned capital expenditures through year-end 2010 in order to bring our planned operating and capital expenditures within our anticipated internally generated cash flow. Our current budgeted capital expenditures for drilling, leasehold and producing property acquisitions, geophysical costs, and additions to midstream, compression and other property and equipment are $4.150 billion to $4.675 billion in 2009 and $4.550 billion to $5.175 billion in 2010.

Cash flow from operations is our primary source of liquidity used to fund operating expenses and capital expenditures. Our $3.5 billion revolving bank credit facility and our $460 million midstream revolving bank credit facility, discussed more fully below, provide us with additional liquidity. In response to the difficulties faced by several financial institutions and to ensure we had ample liquidity available, we borrowed the remaining capacity under our revolving bank credit facility at the end of the third quarter of 2008. As a result, we had borrowings of $3.474 billion and letters of credit of $15 million outstanding under that facility as of December 31, 2008. As of December 31, 2008, we had borrowings of $460 million under the midstream credit facility.

During 2008, we relied on capital markets financings and asset monetization transactions, such as sales of producing properties, undeveloped acreage and non-strategic assets, joint venture arrangements and volumetric production payment, or VPP, transactions to provide us with additional capital. Since March 31, 2008, these types of transactions have provided approximately $12.1 billion of new capital, and up to $4.6 billion of our future drilling and completion costs in the Haynesville, Fayetteville and Marcellus Shales will be funded by our joint venture partners. These transactions are summarized below:

- From April through July of 2008, we issued 51.75 million shares of our common stock, $800 million of our 7.25% Senior Notes due 2018 and $1.380 billion of our 2.25% Contingent Convertible Senior Notes due 2038, resulting in aggregate net proceeds to us of $4.734 billion. The availability of any additional capital from the public or private markets is uncertain at this time.

- In May, August and December of 2008, we completed three separate VPP transactions involving approximately 285 bcfe of proved reserves and net production (at the time of sale) of 153 mmcfe per day from wells in Texas, Oklahoma and Kansas, resulting in aggregate net proceeds to us of $1.6 billion.

- In July of 2008, we entered into a joint venture with Plains Exploration & Production Company to develop our Haynesville Shale leasehold, under the terms of which (1) Plains acquired a 20% interest in our approximately 550,000 net acres of Haynesville Shale leasehold for $1.65 billion in cash, (2) Plains agreed to fund 50% of our 80% share of the costs associated with drilling and completing future Haynesville Shale joint venture wells over a multi-year period, up to an additional $1.65 billion and (3) Plains will have the right to a 20% participation in any additional leasehold we acquire in the Haynesville Shale. Subsequently, in February 2009, we amended the joint venture to provide Plains a one-time option in June 2010 to reduce its obligation to fund our drilling and completion costs by $800 million in exchange for assigning us 50% of its interest in the Haynesville joint venture properties.

- In August of 2008, we sold 90,000 net acres of leasehold and producing natural gas properties with net production (at the time of sale) of 50 mmcfe per day in the Arkoma Basin Woodford Shale play in Oklahoma to BP America Inc. for $1.7 billion in cash.

- In September of 2008, we entered into a joint venture with BP America Inc. to develop our Fayetteville Shale leasehold, under the terms of which (1) BP acquired a 25% interest in our approximately 540,000 net acres of Fayetteville Shale leasehold for $1.1 billion in cash, (2) BP agreed to fund 100% of our 75% share of the costs associated with drilling and completing future Fayetteville Shale joint venture wells over a multi-year period, up to an additional $800 million and (3) BP will have the right to a 25% participation in any additional leasehold we acquire in the Fayetteville Shale.

- In November of 2008, we entered into a joint venture with a U.S. subsidiary of StatoilHydro ASA, under the terms of which StatoilHydro acquired a 32.5% interest in our approximately 1.8 million net acres of Marcellus Shale leasehold for $1.25 billion in cash, (2) StatoilHydro agreed to fund 75% of

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our 67.5% share of the costs associated with drilling and completing future Marcellus Shale joint venture wells over a multi-year period, up to an additional $2.125 billion and (3) StatoilHydro will have the right to a 32.5% participation in any additional leasehold we acquire in the Marcellus Shale. Additionally, Chesapeake and StatoilHydro are evaluating opportunities for an international strategic alliance to jointly explore unconventional natural gas opportunities worldwide.

During the fourth quarter of 2008, we privately exchanged $765 million in aggregate principal amount of our 2.75% Contingent Convertible Senior Notes due 2035, our 2.50% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 23,913,203 shares of our common stock. Our net debt as a percentage of total capitalization (total capitalization is the sum of net debt less cash on hand and stockholders equity) was 43% as of December 31, 2008 and 47% as of December 31, 2007. The average maturity of our long-term debt as of December 31, 2008 was over eight years with an average interest rate of approximately 5.6%. No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

We plan to continue to evaluate asset monetization transactions in order to create additional value from our proved and unproved properties and to increase our financial flexibility. Management believes that our leasehold and development joint ventures and various asset monetization programs benefit the company by improving our asset base, reducing our financial risk, decreasing our DD&A rate and increasing our profitability per unit of production, thereby increasing our returns on capital and advancing future value creation. We may also consider alternative sources of public or private investment in the company or its subsidiaries. While we believe that our anticipated internally generated cash flow, cash resources and other sources of liquidity will allow us to fully fund our 2009 and 2010 operating and capital expenditure requirements, further deterioration of the economy and other factors could require us to fund these expenditures from monetization transactions or further curtail our spending.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity used to fund operating expenses and capital expenditures. Cash provided by operating activities was $5.236 billion in 2008, compared to $4.932 billion in 2007 and $4.843 billion in 2006. The $304 million increase from 2007 to 2008 was primarily due to higher volumes of natural gas and oil production. The $89 million increase from 2006 to 2007 was primarily due to higher volumes of natural gas and oil production. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding non-cash items, such as depreciation, depletion and amortization, deferred income taxes and unrealized gains and (losses) on derivatives. See the discussion below under *Results of Operations*.

Changes in market prices for natural gas and oil directly impact the level of our cash flow from operations. To mitigate the risk of declines in natural gas or oil prices and to provide more predictable future cash flow from operations, we currently have hedged through swaps and collars 78% of our expected remaining natural gas and oil production in 2009 and 48% of our expected natural gas and oil production in 2010 at average prices of $7.71 and $9.02 per mcfe, respectively. Our natural gas and oil hedges as of December 31, 2008 are detailed in Item 7A of this report. Depending on changes in natural gas and oil futures markets and management s view of underlying natural gas and oil supply and demand trends, we may increase or decrease our current hedging positions.

As of December 31, 2008, we had a net natural gas and oil derivative asset of $1.305 billion. We have arrangements with our hedging counterparties that allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations in the value of our natural gas and oil hedges by making collateral allocations from our bank credit facility or directly pledging natural gas and oil properties, rather than posting cash or letters of credit with the counterparties.

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Our $3.5 billion bank credit facility, our $460 million midstream bank credit facility and cash and cash equivalents are other sources of liquidity. Following the February 2009 issuance of $1.425 billion of 9.5% Senior Notes due 2015, there was as of February 26, 2009 $1.864 billion of borrowing capacity available under the revolving bank credit facility and $36 million of borrowing capacity under the midstream credit facility. We use the facilities and cash on hand to fund daily operating activities and acquisitions as needed. We borrowed $13.3 billion and repaid $11.3 billion in 2008, we borrowed $7.9 billion and repaid $6.2 billion in 2007, and we borrowed $8.4 billion and repaid $8.3 billion in 2006 under our bank credit facilities. A substantial portion of our natural gas and oil properties are not currently pledged under debt or hedging arrangements and therefore are available to be pledged as additional collateral under our revolving bank credit facility if needed based on our periodic borrowing base and collateral redeterminations. Accordingly, we believe our borrowing capacity will not be reduced associated with such periodic redeterminations.

On April 2, 2008, we issued 23 million shares of our common stock in a public offering at a price of $45.75 per share, and on July 15, 2008, we issued 28.75 million shares of common stock in a public offering at a price of $57.25 per share. On May 20, 2008 we completed public offerings of $800 million of our 7.25% Senior Notes due 2018 and $1.380 billion of our 2.25% Contingent Convertible Senior Notes due 2038. These four offerings resulted in aggregate net proceeds to us of approximately $4.734 billion, which we used to fund the redemption of our 7.75% Senior Notes due 2015 and to temporarily repay indebtedness outstanding under our revolving bank credit facility. The following table reflects the proceeds from sales of securities we issued in 2008, 2007 and 2006 (in millions):

	2008		2007		2006	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Common stock	$ 2,698	$ 2,598	$	$	$ 1,800	$ 1,759
Contingent convertible senior notes	1,380	1,349	1,650	1,607		
Senior notes	800	787			1,799	1,755
Convertible preferred stock					575	558
Total	$ 4,878	$ 4,734	$ 1,650	$ 1,607	$ 4,174	$ 4,072

In May 2008, we sold a portion of our proved reserves in certain producing assets in Texas, Oklahoma and Kansas in a VPP transaction for proceeds of approximately $616 million, net of transaction costs. We completed another VPP transaction in August 2008, when we sold a portion of our proved reserves in certain producing assets in the Anadarko Basin of Oklahoma for proceeds of approximately $594 million, net of transaction costs. Also, in December 2008, we sold certain long-lived producing assets in the Anadarko and Arkoma Basins in a VPP transaction for proceeds of approximately $412 million, net of transaction costs. Approximately, $43 million of the proceeds are being held in escrow until post-closing adjustments have been finalized. In August 2008, we sold leasehold and producing natural gas properties in the Arkoma Basin Woodford Shale play in Oklahoma for $1.7 billion in cash.

In the second half of 2008, the company entered into three joint venture arrangements covering three of the company s Big 4 shale plays. In the joint ventures, the company has collaborated with other leading energy companies to accelerate the development of the company s properties in the Haynesville Shale, the Fayetteville Shale and the Marcellus Shale. In total, we sold leasehold and producing property assets in which we had a cost basis of approximately $1.2 billion to these three joint venture partners for total cash consideration of $4.0 billion and up to $4.6 billion of future drilling cost carries while we retained a majority interest in each joint venture. The drilling cost carries of up to approximately $4.2 billion that remain unused as of December 31, 2008 will be extremely valuable in the years ahead by enabling the company to develop reserves in these joint venture shale plays at greatly reduced costs. We are also considering opportunities for other joint venture transactions to develop our properties.

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. We refer you to the table under *Investing Activities* below, which sets forth the components of our natural gas and oil investing activities and other investing activities for 2008, 2007 and 2006.

We retain a significant degree of control over the timing of our capital expenditures which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, 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.

We paid dividends on our common stock of $148 million, $115 million and $87 million in 2008, 2007 and 2006, respectively. The Board of Directors increased the quarterly dividend on common stock from $0.0675 to $0.075 per share beginning with the dividend paid in July 2008. Dividends paid on our preferred stock decreased to $35 million in 2008 from $95 million in 2007 and $88 million in 2006 as a result of conversions and exchanges of preferred stock into common stock during 2008 and 2007.

In 2008, holders of our 4.5% cumulative convertible preferred stock and our 5.0% (Series 2005B) cumulative preferred stock exchanged 891,100 shares and 3,654,385 shares for 2,227,750 shares and 10,443,642 shares of common stock, respectively, in privately negotiated exchanges. The exchanges resulted in a loss of $67 million. In 2007, holders of our 5.0% (Series 2005) cumulative convertible preferred stock and 6.25% mandatory convertible preferred stock exchanged 4,535,880 shares and 2,156,184 shares for 19,038,891 and 17,367,823 shares of common stock, respectively, in public exchange offers. The exchanges resulted in a loss $128 million.

We received $9 million, $15 million and $73 million from the exercise of employee and director stock options in 2008, 2007 and 2006, respectively. We paid $5 million, $0 and $86 million to purchase treasury stock in 2008, 2007 and 2006, respectively. Of these amounts, $5 million and $11 million were used to fund our matching contribution to our 401(k) and deferred compensation plans in 2008 and 2006, respectively. The remaining $75 million in 2006 was used to purchase shares of common stock to be used upon the exercise of stock options under certain stock option plans.

In 2008, 2007 and 2006, we paid $167 million, $91 million and $87 million, respectively, to settle a portion of the derivative liabilities assumed in our 2005 acquisition of Columbia Natural Resources, LLC.

SFAS 123(R) requires tax benefits resulting from stock-based compensation deductions in excess of amounts reported for financial reporting purposes to be reported as cash flows from financing activities. In 2008, 2007 and 2006, we reported a tax benefit from stock-based compensation of $43 million, $20 million and $88 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased by $330 million, decreased by $98 million and increased by $70 million in 2008, 2007 and 2006, 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.

Credit Risk

A significant portion of our liquidity is concentrated in both cash and cash equivalents and derivative instruments. On December 31, 2008, our cash and cash equivalents were invested in money market funds with investment grade ratings. A significant portion of these funds was invested at the close of business on September 19, 2008, and is protected under the U.S. Treasury Department s Temporary Guarantee Program. The remaining funds were spread among several counterparties to mitigate risk.

Derivative instruments enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment grade rated counterparties deemed by management to be competent and competitive market makers and spread our instruments among multiple counterparties such that no single counterparty represents a material credit risk to the company. Recently there have been concerns about the ability of certain counterparties to continue to meet their financial obligations. We monitor the creditworthiness of all our counterparties and do not believe a failure by a counterparty would have a material negative impact on our liquidity.

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Our accounts receivable are primarily from purchasers of natural gas and oil ($738 million at December 31, 2008) and exploration and production companies which own interests in properties we operate ($424 million at December 31, 2008). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parental guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

Investing Activities

Cash used in investing activities increased to $9.844 billion in 2008, compared to $7.922 billion in 2007 and $8.942 billion in 2006. We have continued our active drilling program and our acquisitions are focused on leasehold and property acquisitions needed for planned natural gas and oil development. Our investing activities during the past two years reflect our increasing focus on acquiring unproved leasehold and converting our resource inventory into production, redeploying our capital by selling natural gas and oil properties with lower rates of return and increasing our investment in properties with higher return potential, and investing in drilling rigs, midstream systems, compressors and other property and equipment to support our natural gas and oil exploration, development and production activities. The following table shows our cash used in (provided by) investing activities during 2008, 2007 and 2006 (in millions):

Natural Gas and Oil Investing Activities:	**2008**	**2007**	**2006**
Acquisitions of natural gas and oil companies and proved properties, net of cash acquired	$ 372	$ 520	$ 1,104
Acquisition of leasehold and unproved properties	7,660	2,187	3,301
Exploration and development of natural gas and oil properties	5,789	4,962	3,009
Geological and geophysical costs	315	343	154
Interest capitalized on unproved properties	440	254	172
Proceeds from sale of volumetric production payments	(1,579)	(1,089)	
Deposits for acquisitions	12	15	21
Divestitures of proved and unproved properties and leasehold	(6,091)		
Total natural gas and oil investing activities	6,918	7,192	7,761
Other Investing Activities:			
Additions to other property and equipment	3,073	1,439	987
Proceeds from sale of drilling rigs and equipment	(64)	(369)	(244)
Proceeds from sale of compressors	(114)	(188)	
Additions to investments	74	8	554
Proceeds from sale of investments	(2)	(124)	(159)
Acquisition of trucking company, net of cash acquired			45
Sale of other assets	(41)	(36)	(2)
Total other investing activities	2,926	730	1,181
Total cash used in investing activities	$ 9,844	$ 7,922	$ 8,942

Due to the current financial crisis, decreases in natural gas prices and concerns about an oversupply of natural gas in the U.S. market, we and other exploration and production companies have significantly decreased budgets for natural gas and oil investing activities in 2009. In connection with our reduced budget for acquisitions, we are using our common stock for some or all of the consideration for certain transactions. In December 2008, we registered 25 million shares of common stock that we may offer and issue to acquire assets (including mineral interests), businesses or securities of other companies. As of February 26, 2009, we had issued approximately 16 million shares of common stock for leasehold acquisitions and anticipate we may issue the remaining shares over the course of 2009.

Bank Credit Facilities

We have a $3.5 billion syndicated revolving bank credit facility that matures in November 2012. As of December 31, 2008, we had $3.474 billion in outstanding borrowings under this facility and had utilized approximately $15 million of the facility for various letters of credit. To ensure that our revolving credit facility could be fully utilized in these turbulent economic times, we borrowed the remaining capacity under our facility at the end of the third quarter and invested the cash proceeds in short-term highly liquid securities. As a result, on December 31, 2008, we had cash and cash equivalents on hand of approximately $1.749 billion. All 36 lenders that participate in our revolving credit facility fully funded their commitment, with the exception of Lehman Brothers Commercial Bank, a subsidiary of Lehman Brothers Holdings Inc., which has filed for bankruptcy protection. Lehman Brothers Commercial Bank did not fund its $11 million share of the advance.

Borrowings under the facility are secured by certain producing natural gas and oil properties and bear interest at our option 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), plus a margin that varies from 0.75% to 1.50% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently the commitment fee is 0.20% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals. Our subsidiaries, Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake and all its other wholly-owned restricted subsidiaries are guarantors.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.43 to 1 and our indebtedness to EBITDA ratio was 2.43 to 1 at December 31, 2008. 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 of the company and its restricted subsidiaries that we may have with an outstanding principal amount in excess of $75 million.

On October 16, 2008, we closed a new secured revolving bank credit facility for our non-Appalachian midstream operations, which have recently been restructured under a new unrestricted subsidiary, Chesapeake Midstream Partners, L.P. (CMP) and its operating subsidiary, Chesapeake Midstream Operating, L.L.C. (CMO). Twelve financial institutions are in the facility bank group. The facility matures in October 2013, has initial availability of $460 million and may be expanded up to $750 million at CMO s option, subject to additional bank participation. CMO is utilizing the facility to fund capital expenditures associated with building additional natural gas gathering and other systems associated with our drilling program and for general corporate purposes related to our midstream operations. As of December 31, 2008, we had $460 million in outstanding borrowings under the midstream credit facility.

The midstream credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMP and its subsidiaries to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 2.50 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 2.59 to 1 and our EBITDA to interest expense coverage ratio was 9.36 to 1 at December 31, 2008. If CMP or its subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMP and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

Hedging Facilities

We have six 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 a stated maximum value. Outstanding transactions under each facility are collateralized by certain of our natural gas and oil properties that do not secure any of our other obligations. The value of reserve collateral pledged to each facility is required to be at least 1.3 or 1.5 times the fair value of transactions outstanding under each facility. In addition, we may pledge collateral from our revolving bank credit facility, from time to time, to these facilities to meet any additional collateral coverage requirements. The hedging facilities are subject to an annual exposure fee, which is assessed quarterly based on the average of the daily negative fair value amounts of the hedges, if any, during the quarter. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate natural gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time. The fair value of outstanding transactions, per annum exposure fees and the scheduled maturity dates are shown below.

	Secured Hedging Facilities (a)					
	#1	#2	#3	#4	#5	#6
	($ in millions)					
Fair value of outstanding transactions, as of December 31, 2008	$ 116	$ 369	$ 37	$ 9	$ 245	$ 94
Per annum exposure fee	1%	1%	0.8%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2013	2020	2012	2012	2012

(a) Chesapeake Exploration, L.L.C. is the named party to the facilities numbered 1 3 and Chesapeake Energy Corporation is the named party to the facilities numbered 4 6.

Our revolving bank credit facility, the midstream credit facility and the secured hedging facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates and commitment fees in our revolving bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither of our credit facilities nor the secured hedging facilities 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.

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Senior Note Obligations

In addition to outstanding revolving bank credit facility borrowings discussed above, as of December 31, 2008, senior notes represented approximately $10.3 billion of our long-term debt and consisted of the following ($ in millions):

7.5% Senior Notes due 2013	$ 364
7.625% Senior Notes due 2013	500
7.0% Senior Notes due 2014	300
7.5% Senior Notes due 2014	300
7.75% Senior Notes due 2015 (a)	
6.375% Senior Notes due 2015	600
6.625% Senior Notes due 2016	600
6.875% Senior Notes due 2016	670
6.25% Euro-denominated Senior Notes due 2017 (b)	835
6.5% Senior Notes due 2017 (b)	1,100
7.25% Senior Notes due 2018	800
6.25% Senior Notes due 2018	600
6.875% Senior Notes due 2020	500
2.75% Contingent Convertible Senior Notes due 2035 (c)	451
2.5% Contingent Convertible Senior Notes due 2037 (c)	1,378
2.25% Contingent Convertible Senior Notes due 2038 (c)	1,126
Discount on senior notes	(85)
Interest rate derivatives (d)	211
	$ 10,250

(a) The 7.75% Senior Notes due 2015 were redeemed on July 7, 2008. In connection with the transaction we recorded a $31 million loss (which consisted of a $12 million premium and the write-off of $19 million in various charges associated with the notes).

(b) The principal amount shown is based on the dollar/euro exchange rate of $1.3919 to 1.00 as of December 31, 2008. See Note 10 for information on our related cross currency swap.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the fourth quarter of 2008, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the first quarter of 2009 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)

2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$ 48.81	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.47	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(d) See Note 9 for further discussion related to these instruments.

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No scheduled principal payments are required under our senior notes until 2013, when $864 million is due.

As of December 31, 2008 and currently, debt ratings for the senior notes are Ba3 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (stable outlook) and BB by Fitch Ratings (negative outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole redemption prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of December 31, 2008, we estimate that secured commercial bank indebtedness of approximately $5.8 billion could have been incurred under the most restrictive indenture covenant.

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. As of December 31, 2007, our obligations under our outstanding senior notes and contingent convertible notes were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis. Since October 2008, following the restructuring of our non-Appalachian midstream operations, certain of our subsidiaries having significant assets and operations have not guaranteed our outstanding senior notes and contingent convertible notes. Condensed consolidating financial information for Chesapeake and its combined guarantor and combined non-guarantor subsidiaries as of and for the year ended December 31, 2008 is provided in Note 16 of the notes to our consolidated financial statements included in Item 8 of this report.

Contractual Obligations

The table below summarizes our contractual obligations as of December 31, 2008 ($ in millions):

		Payments Due By Period			
	Total	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 years**
Long term debt:					
Principal	$ 14,058	$	$	$ 4,798	$ 9,260
Interest	6,048	567	1,133	1,133	3,215
Capital lease obligations	4	3	1		
Operating lease obligations	946	142	266	270	268
Asset retirement obligations (a)	269	19	21	6	223
Purchase obligations (b)	2,349	807	487	320	735
Unrecognized tax benefits (c)	60		60		
Standby letters of credit	15	15			
Total contractual cash obligations	$ 23,749	$ 1,553	$ 1,968	$ 6,527	$ 13,701

(a) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2008 balance sheet.
(b) See Note 4 of the notes to our consolidated financial statements for a description of transportation and drilling contract commitments.
(c) See Note 5 of the notes to our consolidated financial statements for a description of unrecognized tax benefits.

Chesapeake has commitments to purchase natural gas and oil associated with volumetric production payment transactions that extend over terms ranging from 11 to 15 years based on market prices at the time of production and the purchased gas will be resold. The obligations are as follows:

	Mmcfe
2009	68,238
2010	60,723
2011	53,694
2012	48,069
2013	43,477
After 2013	181,574
Total	455,775

Other Commitments

We own a 49% interest in Mountain Drilling Company, a company that specializes in hydraulic drilling rigs which are designed for drilling in urban areas. Chesapeake has an agreement to lend Mountain Drilling Company up to $32 million through December 31, 2009. At December 31, 2008, Mountain Drilling owed Chesapeake $19 million under this agreement.

We invested in Ventura Refining and Transmission LLC in early 2007 and today own a 25% interest. There were no refineries in western Oklahoma until Ventura opened its refinery in 2006. We have agreed to guarantee various commitments for Ventura, up to $70 million, to support their operating activities. As of December 31, 2008, we had $7 million of outstanding performance guarantees.

Hedging Activities

Natural Gas and Oil Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. 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 its quarterly Board meetings. We believe we have sufficient internal controls to prevent unauthorized hedging. As of December 31, 2008, our natural gas and oil derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options, put 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 natural gas and oil production. We closely monitor the fair value of our hedging contracts and may elect to settle a contract prior to its scheduled maturity date in order to lock in a gain or loss. Commodity markets are volatile and Chesapeake s hedging activities are dynamic.

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Mark-to-market positions under natural gas and oil hedging contracts fluctuate with commodity prices. As described above under *Bank Credit Facilities* and *Hedging Facilities*, we may be required to deliver collateral or other assurances of performance if our payment obligations to our hedging counterparties exceed levels stated in our contracts. Our realized and unrealized gains and losses on natural gas and oil derivatives during 2008, 2007 and 2006 were as follows:

	Years Ended December 31,		
	2008	2007	2006
		($ in millions)	
Natural gas and oil sales	$ 7,069	$ 4,795	$ 3,870
Realized gains (losses) on natural gas and oil derivatives	(8)	1,203	1,254
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	887	(252)	184
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(90)	(122)	311
Total natural gas and oil sales	$ 7,858	$ 5,624	$ 5,619

Changes in the fair value of natural gas and oil derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of derivative contracts are recorded in accumulated other comprehensive income and are transferred to earnings in the month of related production. These unrealized gains (losses), net of related tax effects, totaled $386 million, $53 million and $546 million as of December 31, 2008, 2007 and 2006, respectively. Based upon the market prices at December 31, 2008, we expect to transfer to earnings approximately $345 million of the net gain included in the balance of accumulated other comprehensive income during the next 12 months. A detailed explanation of accounting for natural gas and oil derivatives under SFAS 133 appears under Application of Critical Accounting Policies Hedging elsewhere in this Item 7.

The estimated fair values of our natural gas and oil derivative instruments as of December 31, 2008 and 2007 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31,	
	2008	2007
	($ in millions)	
Derivative assets (liabilities) (a):		
Fixed-price natural gas swaps	$ 863	$ (54)
Fixed-price natural gas collars	402	4
Natural gas basis protection swaps	93	151
Fixed-price natural gas knockout swaps	141	108
Natural gas call options	(178)	(230)
Natural gas put options	(39)	
Fixed-price oil swaps	31	(110)
Fixed-price oil knockout swaps	19	(125)
Fixed-price oil cap-swaps	3	(17)
Oil call options	(35)	(96)
Fixed-price oil collars	5	
Estimated fair value	$ 1,305	$ (369)

(a) See Item 7A. Quantitative and Qualitative Disclosures About Market Risk of this report for additional information concerning any associated premiums received, or discounts paid, in connection with certain derivative transactions.

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

	2008	2007	2006
		($ in millions)	
Fair value of contracts outstanding, as of January 1	$ (369)	$ 345	$ (946)
Change in fair value of contracts	1,880	972	3,423
Fair value of contracts when entered into	(569)	(295)	(32)
Contracts realized or otherwise settled	9	(1,203)	(1,254)
Fair value of contracts when closed	354	(188)	(846)
Fair value of contracts outstanding, as of December 31	$ 1,305	$ (369)	$ 345

Interest Rate Derivatives

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

Gains or losses from derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. Realized gains (losses) included in interest expense were $6 million, ($1) million and ($2) million in 2008, 2007 and 2006, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were ($85) million, ($40) million and $2 million in 2008, 2007 and 2006, respectively. A detailed explanation of accounting for interest rate derivatives under SFAS 133 appears under Application of Critical Accounting Policies Hedging elsewhere in this Item 7.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. A detailed explanation of accounting for foreign currency derivatives under SFAS 133 appears under Application of Critical Accounting Policies Hedging elsewhere in this Item 7.

Results of Operations

General. For the year ended December 31, 2008, Chesapeake had net income of $723 million, or $1.14 per diluted common share, on total revenues of $11.629 billion. This compares to net income of $1.451 billion, or $2.62 per diluted common share, on total revenues of $7.800 billion during the year ended December 31, 2007, and net income of $2.003 billion, or $4.35 per diluted common share, on total revenues of $7.326 billion during the year ended December 31, 2006.

Natural Gas and Oil Sales. During 2008, natural gas and oil sales were $7.858 billion compared to $5.624 billion in 2007 and $5.619 billion in 2006. In 2008, Chesapeake produced and sold 842.7 bcfe of natural gas and oil at a weighted average price of $8.38 per mcfe, compared to 714.3 bcfe in 2007 at a weighted average price of $8.40 per mcfe, and 578.4 bcfe in 2006 at a weighted average price of $8.86 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of $797 million, ($374) million and $495 million in 2008, 2007 and 2006, respectively). The decrease in prices in 2008 resulted in a decrease in revenue of $17 million and increased production resulted in a $1.079 billion increase, for a total increase in revenues of $1.062 billion (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from period to period was primarily generated from the drillbit.

For 2008, we realized an average price per mcf of natural gas of $8.09, compared to $8.14 in 2007 and $8.76 in 2006 (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $70.48, $67.50 and $59.14 in 2008, 2007 and 2006, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net decrease in natural gas and oil revenues of ($9) million or ($0.01) per mcfe in 2008, a net increase of $1.203 billion or $1.68 per mcfe in 2007 and a net increase of $1.254 billion or $2.17 per mcfe in 2006.

A change in natural gas and oil prices has a significant impact on our natural gas and oil revenues and cash flows. Assuming 2008 production levels, a change of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2008 revenues and cash flows of approximately $78 million and $75 million, respectively, and a change of $1.00 per barrel of oil sold would result in an increase or decrease in 2008 revenues and cash flows of approximately $11 million without considering the effect of hedging activities.

The following table shows our production by region for 2008, 2007 and 2006:

	Years Ended December 31,					
	2008		2007		2006	
	Mmcfe	Percent	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent (a) (b)	412,825	49%	373,941	52%	315,173	55%
Barnett Shale	181,523	22	93,463	13	44,482	7
Permian and Delaware Basins	79,645	10	64,897	9	48,510	8
South Texas and Texas Gulf Coast	70,903	8	78,228	11	79,178	14
Ark-La-Tex	61,543	7	55,811	8	46,009	8
Appalachian Basin (c)	36,305	4	47,922	7	45,031	8
Total Production	842,744	100%	714,262	100%	578,383	100%

(a) 2008 was impacted by the sale of 11.1 bcf and 6.9 bcf of production in VPP transactions that closed on May 1, 2008 and August 1, 2008, respectively.
(b) 2008 was impacted by the sale of 7.6 bcf and 4.7 bcf of production from Arkoma and Fayetteville properties, respectively.
(c) 2008 was impacted by the sale of 18.3 bcf of production in a VPP transaction that closed on December 31, 2007.

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in 2008, compared to 92% in 2007 and 91% in 2006.

Natural Gas and Oil Marketing Sales and Operating Expenses. Natural gas and oil marketing activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $3.598 billion in natural gas and oil marketing sales to third parties in 2008, with corresponding natural gas and oil marketing expenses of $3.505 billion, for a net margin before depreciation of $93 million. This compares to sales of $2.040 billion and $1.577 billion, expenses of $1.969 billion and $1.522 billion, and margins before depreciation of $71 million and $55 million in 2007 and 2006, respectively. The net margin increase in 2008 and 2007 is primarily due to an increase in volumes related to natural gas and oil marketing sales.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake recognized $173 million in service operations revenue in 2008 with corresponding service operations expenses of $143 million, for a net margin before depreciation of $30 million. This compares to revenue of $136 million and $130 million, expenses of $94 million and $68 million and a net margin before depreciation of $42 million and $62 million in 2007 and 2006, respectively. These operations have grown as a result of assets and businesses we acquired and leased as seen in the growth in revenues. However, the net margins have decreased each of the previous three years. This is the result of increased expenses associated with the leasing cost of the numerous rigs we have sold and leased back in the previous three years.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $889 million in 2008, compared to $640 million and $490 million in 2007 and 2006, respectively. On a unit-of-production basis, production expenses were $1.05 per mcfe in 2008 compared to $0.90 and $0.85 per mcfe in 2007 and 2006, respectively. The expense increase in 2008 was primarily due to higher third-party field service costs, energy costs, fuel costs, ad valorem taxes and personnel costs. Our per unit increase in 2008 was also affected by the loss of production related to the sale of the volumetric production payments. We expect that production expenses per mcfe produced for 2009 will range from $1.10 to $1.20.

Production Taxes. Production taxes were $284 million in 2008 compared to $216 million in 2007 and $176 million in 2006. On a unit-of-production basis, production taxes were $0.34 per mcfe in 2008 compared to $0.30 per mcfe in 2007 and $0.31 per mcfe in 2006. The $68 million increase in production taxes from 2007 to 2008 is due to an increase in production of 128 bcfe and an increase in the realized average sales price of natural gas and oil of $1.68 per mcfe (excluding gains or losses on derivatives).

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. We expect production taxes for 2009 to range from $0.25 to $0.35 per mcfe based on estimated NYMEX prices ranging from $6.00 to $7.50 per mcf of natural gas and an oil price of $47.66 per barrel.

General and Administrative Expense. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties (see Note 10 of notes to consolidated financial statements), were $377 million in 2008, $243 million in 2007 and $139 million in 2006. General and administrative expenses were $0.45, $0.34 and $0.24 per mcfe for 2008, 2007 and 2006, respectively. The increase in 2008, 2007 and 2006 was the result of increasing labor costs due to the company s continued growth as well as increased media and advocacy expenditures. Included in general and administrative expenses is stock-based compensation of $85 million in 2008, $58 million in 2007 and $27 million in 2006. The increase was mainly due to an increase in the number of unvested restricted shares outstanding during 2008 compared to 2007 and 2006 as a result of growth in our employment. We anticipate that general and administrative expenses for 2009 will be between $0.33 and $0.37 per mcfe produced, including stock-based compensation ranging from $0.10 to $0.12 per mcfe produced.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Employee restricted stock awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 1 and Note 8 of notes to the consolidated financial statements included in Item 8 of this report provides additional detail on the accounting for and reporting of our stock-based compensation.

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil 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 $352 million, $262 million and $161 million of internal costs in 2008, 2007 and 2006, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $1.970 billion, $1.835 billion and $1.359 billion during 2008, 2007 and

2006, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $2.34, $2.57 and $2.35 in 2008, 2007 and 2006, respectively. The decrease in the average rate from $2.57 in 2007 to $2.34 in 2008 is due primarily to the reduction of our natural gas and oil full-cost pool resulting from our divestitures in 2008 and the addition of reserves through our exploration activities. We expect the 2009 DD&A rate to be between $1.90 and $2.00 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $177 million in 2008, compared to $154 million in 2007 and $104 million in 2006. The average D&A rate per mcfe was $0.21, $0.22 and $0.18 in 2008, 2007 and 2006, respectively. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over 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 ten years. To the extent company-owned drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs. We expect 2009 depreciation and amortization of other assets to be between $0.24 and $0.28 per mcfe produced.

Impairment of Natural Gas and Oil Properties and Other Fixed Assets. Due to lower commodity prices at December 31, 2008, we reported a non-cash impairment charge of $2.8 billion for 2008. We account for our natural gas and oil properties using the full-cost method of accounting, which limits the amount of costs we can capitalize and requires us to write off these costs if the carrying value of natural gas and oil assets in the evaluated portion of our full-cost pool exceeds the sum of the present value of expected future net cash flows of proved reserves using a 10% pre-tax discount rate based on constant pricing and cost assumptions and the present value of certain natural gas and oil hedges. Additionally in 2008, we recorded an impairment of $30 million associated with certain of our midstream assets.

Employee Retirement Expense. Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward s Resignation Agreement provided for the immediate vesting of all of his unvested equity awards, which consisted of options to purchase 724,615 shares of Chesapeake s common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock. As a result of this vesting, we incurred an expense of $55 million in 2006.

Interest and Other Income. Interest and other income was ($11) million, $15 million and $26 million in 2008, 2007 and 2006, respectively. The 2008 loss consisted of $22 million of interest income, a $38 million loss related to our equity in the net losses of certain investments, a $4 million gain on sale of assets, $10 million of expense related to consent solicitation fees and $11 million of miscellaneous income. The 2007 income consisted of $8 million of interest income and $7 million of miscellaneous income. Income related to equity investments was not significant in 2007. The 2006 income consisted of $5 million of interest income, $10 million of income related to equity investments, a $5 million gain on sale of assets and $6 million of miscellaneous income.

Interest Expense. Interest expense decreased to $314 million in 2008 compared to $406 million in 2007 and $301 million in 2006 as follows:

	Years Ended December 31,		
	2008	2007	2006
	($ in millions)		
Interest expense on senior notes and revolving bank credit facility	$ 687	$ 616	$ 472
Capitalized interest	(464)	(269)	(179)
Amortization of loan discount and other	12	17	7
Unrealized (gain) loss on interest rate derivatives	85	41	(1)
Realized (gain) loss on interest rate derivatives	(6)	1	2
Total interest expense	$ 314	$ 406	$ 301
Average long-term borrowings	$ 10,044	$ 8,224	$ 6,278

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Interest expense, excluding unrealized (gains) losses on interest rate derivatives was $0.27 per mcfe in 2008 compared to $0.51 per mcfe in 2007 and $0.52 per mcfe in 2006. The decrease in interest expense per mcfe for 2008 is due to increased production volumes and an increase in capitalized interest. Capitalized interest increased in 2008 and 2007 as a result of a significant increase in unevaluated properties, the base on which interest is capitalized. We expect interest expense for 2009 to be between $0.30 and $0.35 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Exchanges or Repurchases of Chesapeake Debt. In 2008, we redeemed $300 million of our 7.75% Senior Notes due 2015 with proceeds from the issuance of new senior notes with a lower rate of interest. In connection with the redemption, we recorded a $31 million loss (which consisted of a $12 million premium and the write-off of $19 million in various charges associated with the notes). Also in 2008, we privately exchanged approximately $765 million in aggregate principal amount of our 2.75% Contingent Convertible Senior Notes due 2035, our 2.50% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 23,913,203 shares of our common stock. The difference between the face value of the notes that were exchanged and the fair value of the common stock issued resulted in a gain of $268 million on the cancellation of indebtedness.

Impairment of Investments. In 2008, we recorded a $180 million impairment of certain investments. Each of our investees has been impacted by the dramatic slowing of the worldwide economy and the freezing of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness has resulted in significantly reduced natural gas and oil prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized that an other than temporary impairment had occurred on the following investments: Chaparral Energy, Inc., $100 million; DHS Drilling Company, $20 million; Mountain Drilling Company, $10 million; and Ventura Refining and Transmission LLC, Inc., $50 million.

Gain on Sale of Investments. In 2007, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $124 million and a gain of $83 million. In 2006, Chesapeake sold its investment in publicly-traded Pioneer Drilling Company common stock, realizing proceeds of $159 million and a gain of $117 million. At the time of sale, we owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

Income Tax Expense. Chesapeake recorded income tax expense of $463 million in 2008 compared to income tax expense of $890 million in 2007 and $1.252 billion in 2006. Of the income tax expense recorded in 2008, $423 million is reflected as current income tax expense and $40 million is reflected as deferred income tax expense. The divestitures that closed during 2008 are projected to generate sufficient taxable income for the year to exhaust all our non-limited NOLs and result in a current tax liability for the tax year ended December 31, 2008. Of the $427 million decrease in 2008, $439 million was the result of the decrease in net income before taxes which was offset by $12 million as the result of an increase in the effective tax rate. Our effective income tax rate was 39% in 2008 compared to 38% in 2007 and 38.5% in 2006. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences. We expect our effective income tax rate to be 39% in 2009.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $67 million, $128 million and $10 million in 2008, 2007 and 2006, respectively. The loss on the exchanges represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms. See Note 8 of notes to the consolidated financial statements in Item 8 for further detail regarding these transactions.

Application of Critical Accounting Policies

Readers of this report and users of the information contained in it should be aware of how certain events may impact our financial results based on the accounting policies in place. The four policies we consider to be

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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 are 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 natural gas and oil, changes in interest rates and changes in foreign exchange rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of natural gas and oil derivative transactions are reflected in natural gas and oil sales, and results of interest rate and foreign exchange rate hedging transactions are reflected in interest expense. The changes in the fair value of derivative instruments not qualifying for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within natural gas and oil 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 natural gas and oil sales. For derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. See Hedging Activities above and Item 7A Quantitative and Qualitative Disclosures About Market Risk for additional information regarding our hedging activities.

One of the primary factors that can have an impact on our results of operations is the method used to value our derivatives. We have established the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

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

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Due to the volatility of natural gas and oil prices and, to a lesser extent, interest rates and foreign exchange rates, the company s financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2008, 2007 and 2006, the net market value of our derivatives was an asset of $1.305 billion, a liability of $375 million and an asset of $293 million, respectively. The derivatives that we acquired in our CNR acquisition represented $17 million, $184 million and $254 million of liability at December 31, 2008, 2007 and 2006.

Natural Gas and Oil Properties. The accounting for our business is subject to special accounting rules that are unique to the natural gas and oil industry. There are two allowable methods of accounting for natural gas and oil 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 natural gas and oil 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 natural gas and oil 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 natural gas and oil depreciation, depletion and amortization rate, and we will not have exploration expenses that successful efforts companies frequently have.

Under the full-cost method, capitalized costs are amortized on a composite unit-of-production method based on proved natural gas and oil 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 proved reserves, 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 natural gas and oil 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. As of December 31, 2008, capitalized costs of natural gas and oil properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in a write-down in the carrying value of natural gas and oil properties of $2.8 billion. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Based on spot prices for natural gas and oil as of December 31, 2008, these cash flow hedges increased the full-cost ceiling by $1.024 billion, thereby reducing the ceiling test write-down by the same amount.

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.

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Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, natural gas and oil prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

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

Our internal petroleum reservoir engineers evaluated and estimated all of our proved reserves as of December 31, 2008, and independent petroleum engineers audited approximately 76% of our estimated proved reserves (by volume). 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 2008 year-end reserve evaluation is included under Natural Gas and Oil Reserves in Item 1 Business.

Income Taxes. As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which Chesapeake operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as derivative instruments, depreciation, depletion and amortization, and certain accrued liabilities for tax and accounting purposes. These differences and our net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent Chesapeake establishes a valuation allowance or increases or decreases this allowance in a period, we must include an expense or reduction of expense within the tax provision 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, 2008, we had deferred tax assets of $347 million.

FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109,* provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, *Accounting for Income Taxes.* FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. Based on this guidance, we regularly analyze tax positions taken or expected to be taken in a tax return based on the threshold condition prescribed under FIN 48. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. We accrue interest related to these uncertain tax positions which is recognized in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses. Additional information about uncertain tax positions appears in Income Taxes in Item 1 Business.

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

Disclosures About Effects of Transactions with Related Parties

Since Chesapeake was founded in 1989, our CEO, Aubrey K. McClendon, has acquired working interests in virtually all of our natural gas and oil properties by participating in our drilling activities under the terms of the Founder Well Participation Program (FWPP) and predecessor participation arrangements provided for in Mr. McClendon s employment agreements. Under the FWPP, approved by our shareholders in June 2005, Mr. McClendon may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake s Board of Directors not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the FWPP, which, among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake s working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation.

On December 31, 2008, we entered into a new five-year employment agreement with Mr. McClendon that contained a one-time well cost incentive award to him. The total cost of the award to Chesapeake was $75 million plus employment taxes in the amount of approximately $1 million. We will recognize the incentive award as general and administrative expense over the five-year vesting period for the clawback described below, resulting in an expense of approximately $15 million per year beginning in 2009. In addition to state and federal income tax withholding, similar employment taxes were imposed on Mr. McClendon and withheld from the award. The net incentive award of approximately $44 million can only be applied against costs attributable to interests in company wells acquired by Mr. McClendon or his affiliates under the FWPP. The incentive award is subject to a clawback if, during the initial five-year term of the employment agreement, Mr. McClendon resigns from the company or is terminated for cause by the company. Upon receipt of the company s monthly invoice for joint interest billings in mid-January 2009, Mr. McClendon elected to apply approximately $19 million of the drilling credit against his December 2008 FWPP joint interest billings, leaving $25 million available as a credit against future billings. Based on our current development plans and Mr. McClendon s election under the FWPP to participate with a 2.5% working interest during 2009, the well costs under the FWPP are expected to exceed the amount of the entire FWPP credit in early 2009. We refer you to the discussion of the FWPP and Mr. McClendon s employment agreement contained in our proxy statement for our 2009 annual meeting of shareholders, which discussion is incorporated by reference in Part III of this report.

As disclosed in Note 14, in 2008, Chesapeake had revenues of $1.3 billion from natural gas and oil sales to Eagle Energy Partners I, L.P., a former affiliated entity. We sold our 33% limited partnership interest in Eagle Energy in June 2007.

Recently Issued Accounting Standards

The FASB recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51.* This statement requires an entity to separately disclose non-controlling interests as a separate component of equity in the balance sheet and clearly identify on the face of the income statement net income related to non-controlling interests. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. The adoption of this statement will not have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (R), *Business Combinations.* This statement requires assets acquired and liabilities assumed to be measured at fair value as of the acquisition date, acquisition-related costs incurred prior to the acquisition to be expensed and contractual contingencies to be recognized at fair value as of the acquisition date. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We will comply with this statement prospectively in accounting for future business combinations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133.* This statement changes the disclosure requirements for derivative instruments and hedging activities. The statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. This statement will not have a material impact on our financial disclosures.

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement).* FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon either mandatory or optional conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants.* The accounting prescribed by FSP APB 14-1 increases the amount of

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interest expense required to be recognized with respect to such instruments and, thus, lowers reported net income and net income per share of issuers of such instruments. Issuers must account for the liability and equity components of the instrument separately and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. We have three debt series that will be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038. This staff position is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008 and must be applied on a retrospective basis. The initial adoption of FSP APB 14-1 is expected to decrease the carrying value of our Contingent Convertible Senior Notes by approximately $1 billion, increase shareholders equity by approximately $600 million and increase deferred tax liabilities by approximately $400 million. In addition, we currently estimate that we will record additional non-cash interest expense, which will reduce our pre-tax income by approximately $80 million and reduce net income by approximately $50 million for the year ended December 31, 2009.

In June 2008, the FASB issued FSP Emerging Issues Task Force (EITF) No. 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.* FSP EITF 03-6-1 addresses whether instruments granted in share-based payments transactions are participating securities prior to vesting and therefore need to be included in the earnings allocation in calculating earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. FSP EITF No. 03-6-1 requires companies to treat unvested share-based payment awards that have non-forfeitable rights to dividend or dividend equivalents as a separate class of securities in calculating earnings per share. FSP EITF No. 03-6-1 is effective for fiscal years beginning after December 15, 2008; earlier application is not permitted. FSP EITF No. 03-6-1 could be applicable to us but we have no current transactions that would be affected.

In October 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active.* FSP FAS 157-3 clarifies the application of FASB statement No. 157, Fair Value Measurements, in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP could be applicable to us but we currently have no financial assets of this type.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualifications of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit reserves estimates. The new rules also require that oil and gas reserves be reported and the full-cost ceiling value calculated using an average price based upon the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are in the process of assessing the impact of these new requirements on our financial position, results of operations and financial disclosures.

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 estimates of natural gas and oil reserves, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned capital expenditures, and anticipated asset acquisitions and sales, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures 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.

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

- the volatility of natural gas and oil prices,
- the limitations our level of indebtedness may have on our financial flexibility,
- impacts the current financial crisis may have on our business and financial condition,
- declines in the values of our natural gas and oil properties resulting in ceiling test write-downs,
- the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs,
- our ability to replace reserves and sustain production,
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the timing of development expenditures,
- exploration and development drilling that does not result in commercially productive reserves,
- leasehold terms expiring before production can be established,
- hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities,
- uncertainties in evaluating natural gas and oil reserves of acquired properties and potential liabilities,
- the negative effect lower natural gas and oil prices could have on our ability to borrow,
- drilling and operating risks, including potential environmental liabilities,
- transportation capacity constraints and interruptions that could adversely affect our cash flow,
- adverse effects of governmental and environmental regulation, and

losses possible from pending or future litigation.

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

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

Natural Gas and Oil Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2008, our natural gas and oil derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options, put options and collars. These instruments allow us to predict with greater certainty the effective natural gas and oil 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.

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

For knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

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.

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

For put options, Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. If the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall. If the market price settles above the fixed price of the put option, no payment is due from Chesapeake.

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

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

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

Gains or losses from certain derivative transactions are reflected as adjustments to natural gas and oil sales on the consolidated statements of operations. Realized gains (losses) are included in natural gas and oil sales in the month of related production. 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 natural gas and oil sales. Following provisions of SFAS 133, changes in the fair value of

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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 natural gas and oil sales as unrealized gains (losses). The components of natural gas and oil sales for the years ended December 31, 2008, 2007 and 2006 are presented below.

	Years Ended December 31,		
	2008	2007	2006
		($ in millions)	
Natural gas and oil sales	$ 7,069	$ 4,795	$ 3,870
Realized gains (losses) on natural gas and oil derivatives	(8)	1,203	1,254
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	887	(252)	184
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(90)	(122)	311
Total natural gas and oil sales	$ 7,858	$ 5,624	$ 5,619

As of December 31, 2008, we had the following open natural gas and oil derivative instruments (including derivatives assumed through our acquisition of CNR in November 2005) designed to hedge a portion of our natural gas and oil production for periods after December 2008:

	Volume	Weighted Average Fixed Price to be Received	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at December 31, 2008 ($ in millions)
Natural Gas (bbtu):								
Swaps:								
Q1 2009	81,760	$ 8.17	$	$	$	Yes	$	$ 169
Q2 2009	57,518	8.39				Yes		148
Q3 2009	59,114	8.47				Yes		138
Q4 2009	72,584	8.42				Yes		121
2010	98,249	9.74				Yes		250
2011	23,725	8.51				Yes		27
Collars:								
Q1 2009	14,580		7.63	8.98		Yes		28
Q2 2009	17,290		7.50	8.36		Yes		31
Q3 2009	20,520		7.50	8.35		Yes		31
Q4 2009	16,290		7.50	8.35		Yes		17
Knockout Swaps:								
Q1 2009	9,150	10.09	6.03			No	5	6
Q2 2009	2,730	8.52	6.00			No	6	1
Q3 2009	2,760	8.64	6.00			No	6	1
Q4 2009	39,970	9.79	6.30			No	6	14
2010	321,150	9.78	6.23			No	1	106
2011	138,600	9.74	6.31			No		16
2012	18,300	9.60	6.50			No		(3)
Basis Protection Swaps (Mid-Continent):								
Q1 2009	26,873				(0.47)	No		25
Q2 2009	16,457				(0.27)	No		18
Q3 2009	16,821				(0.27)	No		11
Q4 2009	16,953				(0.27)	No		13
2011	45,090				(0.64)	No	(3)	14
2012 2018	57,961				(0.62)	No	(3)	10
Basis Protection Swaps (Appalachian Basin):								
2009	16,913				0.28	No		
2010	10,199				0.26	No		1
2011	12,086				0.25	No		1
2012 2022	134				0.11	No		

Other Swaps (a):				
Q1 2009	4,500	10.14	No	19
Q2 2009	4,550	9.86	No	5
Q3 2009	4,600	9.94	No	5
Q4 2009	4,600	10.24	No	7
2010	32,850	9.89	No	(7)
2011	4,500	8.73	No	(2)

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	Volume	Weighted Average Fixed Price to be Received	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at December 31, 2008 ($ in millions)
Call Options:								
Q1 2009	20,355	$	$	$ 9.95	$	No	$ 30	$
Q2 2009	27,765			9.59		No	28	(3)
Q3 2009	27,160			9.54		No	29	(6)
Q4 2009	28,980			9.69		No	28	(14)
2010	231,775			10.77		No	223	(58)
2011	138,700			10.59		No	153	(59)
2012 2017	76,820			11.29		No	57	(38)
Put Options:								
2009	36,500		5.75			No	3	(21)
2010	36,500		5.75			No	3	(18)
Other Collars:								
Q1 2009	35,550		5.24/7.95	9.90		No		73
Q2 2009	81,135		5.24/6.99	9.18		No		103
Q3 2009	85,060		5.24/6.98	9.16		No	(1)	90
Q4 2009	44,860		5.39/7.28	9.49		No	(1)	42
2010	25,550		6.00/7.71	11.46		No	21	29
2011	25,550		6.00/7.57	10.69		No	21	13
2012 2020	87,680		5.00/7.08	10.20		No	58	(53)
CNR Swaps (b):								
Q1 2009	4,500	5.18				Yes		(3)
Q2 2009	4,550	5.18				Yes		(3)
Q3 2009	4,600	5.18				Yes		(4)
Q4 2009	4,600	5.18				Yes		(7)
CNR Collars (b):								
2009	3,650		4.50	6.00		Yes		(2)
Total Natural Gas							670	1,282
Oil (mbbls):								
Knockout Swaps:								
Q1 2009	855	80.35	55.95			No		3
Q2 2009	865	80.43	55.95			No		1
Q3 2009	1,978	83.10	58.21			No		
Q4 2009	1,978	83.05	58.21			No		(1)
2010	4,745	90.25	60.00			No		4
2011	1,095	104.75	60.00			No		7
2012	732	109.50	60.00			No		5
Cap Swaps:								
Q1 2009	180	67.50	50.00			No		2
Q2 2009	182	67.50	50.00			No		1
Other Swaps:								
Q1 2009	900	86.25				No		34
Q2 2009	910	86.25				No		29
Counter Swaps:								
Q1 2009	(841)	67.79				No		(16)
Q2 2009	(819)	67.00				No		(11)
Q3 2009	(230)	69.10				No		(3)
Q4 2009	(230)	69.10				No		(2)
Call Options:								
2009	5,110			101.79		No	3	(9)
2010	6,935			107.86		No	(10)	(20)
2011	3,650			185.00		No	36	(2)
2012	3,660			185.00		No	37	(4)
Other Collars:								
2010	730		90.00/80.00	136.40		No		5
Total Oil							66	23

Total Natural Gas and Oil	$	736	$	1,305

(a) These include options to extend an existing swap for an additional 12 months at 50,000 mmbtu/day at $8.73/mmbtu. The options are callable by the counterparty in March 2009 and March 2010 and 40,000 mmbtu/day at $11.35/mmbtu, callable by the counterparty in December 2009.

(b) We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($45 million liability remaining as of December 31, 2008). The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our natural gas and oil revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to natural gas and oil 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 natural gas and oil revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

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

We have established the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

Based upon the market prices at December 31, 2008, we expect to transfer approximately $345 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next twelve months in the related month of production. All transactions hedged as of December 31, 2008 are expected to mature by December 31, 2022.

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

	2008	2007	2006
		($ in millions)	
Fair value of contracts outstanding, as of January 1	$ (369)	$ 345	$ (946)
Change in fair value of contracts	1,880	972	3,423
Fair value of contracts when entered into	(569)	(295)	(32)
Contracts realized or otherwise settled	9	(1,203)	(1,254)
Fair value of contracts when closed	354	(188)	(846)
Fair value of contracts outstanding, as of December 31	$ 1,305	$ (369)	$ 345

The change in the fair value of our derivative instruments since January 1, 2008 resulted from new contracts entered into, the settlement of derivatives for a realized gain, as well as a decrease in natural gas and oil 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 natural gas and oil 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.

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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, 2008, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity ($ in millions)						
	2009	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**
Liabilities:							
Long-term debt fixed-rate (a)	$	$	$	$	$ 864	$ 9,260	$ 10,124
Average interest rate					7.6	5.4	5.6
Long-term debt variable rate	$	$	$	$ 3,474	$ 460	$	$ 3,934
Average interest rate				1.8	3.0		2.0

(a) This amount does not include the discount included in long-term debt of ($85) million and interest rate derivatives of $211 million. Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving bank credit facility. All of our other long-term indebtedness is fixed rate and, therefore, does not expose us to the risk of earnings or cash flow loss due to changes in market interest rates. However, changes in interest rates do affect the fair value of our debt.

Interest Rate Derivatives

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

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense in the consolidated statements of operations. Realized gains (losses) included in interest expense were $6 million, ($1) million and ($2) million in 2008, 2007 and 2006, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were ($85) million, ($40) million and $2 million in 2008, 2007 and 2006, respectively.

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As of December 31, 2008, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate (b)	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Interest Rate:						
Swaps						
January 2008 November 2020	$ 750	6.75%	6 mL plus 224 bp	Yes	$	$ 115
Call Options						
February 2009 May 2009	$ 750	6.75%	6 mL plus 224 bp	No	11	(105)
Swaption						
January 2009	$ 250	6.50%	6 mL plus 200 bp	No	3	
Floating to Fixed Interest Rate:						
Swaps						
August 2007 August 2010	$ 825	4.74%	1 3 mL	No		(27)
Collars (a)						
August 2007 August 2010	$ 800	4.52%	6 mL	No		(35)
Swaption						
August 2009	$ 500	2.56%	1 mL	No	5	(10)
					$ 19	$ (62)

(a) The collars have ceiling and floor fixed interest rates of 5.37% and 4.52%, respectively.

(b) Month LIBOR has been abbreviated mL and basis points has been abbreviated bp .

In 2008, we closed interest rate derivatives for gains totaling $110 million of which $30 million was recognized in interest expense. The remaining $80 million was from interest rate derivatives designated as fair value hedges and the settlement amounts received will be amortized as a reduction to interest expense over the remaining term of the related senior notes ranging from five to twelve years.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties will pay Chesapeake 19 million and Chesapeake will pay the counterparties $30 million, which will yield an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($835 million at December 31, 2008) using an exchange rate of $1.3919 to 1.00. The fair value of the cross currency swap is recorded on the consolidated balance sheet as a liability of $77 million at December 31, 2008.

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

INDEX TO FINANCIAL STATEMENTS

CHESAPEAKE ENERGY CORPORATION

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management has performed an assessment of the effectiveness of the Company s internal control over financial reporting and has determined the Company s internal control over financial reporting was effective as of December 31, 2008.

The effectiveness of the Company s internal control over financial reporting as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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

/s/ MARCUS C. ROWLAND
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,

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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Tulsa, Oklahoma

March 2, 2009

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,749	$ 1
Accounts receivable	1,324	1,074
Short-term derivative instruments	1,082	203
Inventory	58	87
Other	79	31
Total Current Assets	4,292	1,396
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	28,965	27,656
Unevaluated properties	11,216	5,641
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(11,866)	(7,112)
Total natural gas and oil properties, at cost based on full-cost accounting	28,315	26,185
Other property and equipment:		
Natural gas gathering systems and treating plants	2,717	1,135
Buildings and land	1,513	816
Drilling rigs and equipment	430	106
Natural gas compressors	184	63
Other	482	327
Less: accumulated depreciation and amortization of other property and equipment	(496)	(295)
Total Other Property and Equipment	4,830	2,152
Total Property and Equipment	33,145	28,337
OTHER ASSETS:		
Investments	444	612
Long-term derivative instruments	261	4
Other assets	302	385
Total Other Assets	1,007	1,001
TOTAL ASSETS	$ 38,444	$ 30,734

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	December 31, 2008	December 31, 2007
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 1,611	$ 1,262
Short-term derivative instruments	66	174
Accrued liabilities	880	712
Deferred income taxes	358	
Income taxes payable	108	5
Revenues and royalties due others	431	433
Accrued interest	167	175
Total Current Liabilities	3,621	2,761
LONG-TERM LIABILITIES:		
Long-term debt, net	14,184	10,950
Deferred income tax liabilities	3,763	3,966
Asset retirement obligations	269	236
Long-term derivative instruments	111	408
Revenues and royalties due others	49	42
Other liabilities	150	241
Total Long-Term Liabilities	18,526	15,843
CONTINGENCIES AND COMMITMENTS (Note 4)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
4.50% cumulative convertible preferred stock, 2,558,900 and 3,450,000 shares issued and outstanding as of December 31, 2008 and 2007, respectively, entitled in liquidation to $256 million and $345 million, respectively	256	345
5.00% cumulative convertible preferred stock (Series 2005B) 2,095,615 and 5,750,000 shares issued and outstanding as of December 31, 2008 and 2007, respectively, entitled in liquidation to $209 million and $575 million, respectively	209	575
6.25% mandatory convertible preferred stock, 143,768 shares issued and outstanding as of December 31, 2008 and 2007, entitled in liquidation to $36 million	36	36
4.125% cumulative convertible preferred stock, 3,033 and 3,062 shares issued and outstanding as of December 31, 2008 and 2007, respectively, entitled in liquidation to $3 million	3	3
5.00% cumulative convertible preferred stock (Series 2005), 5,000 shares issued and outstanding as of December 31, 2008 and 2007, entitled in liquidation to $1 million	1	1
Common Stock, $.01 par value, 750,000,000 shares authorized, 607,953,437 and 511,648,217 shares issued December 31, 2008 and 2007, respectively	6	5
Paid-in capital	10,835	7,032
Retained earnings	4,694	4,150
Accumulated other comprehensive income (loss), net of tax of ($163) million and $6 million, respectively	267	(11)
Less: treasury stock, at cost; 657,276 and 500,821 common shares as of December 31, 2008 and 2007, respectively	(10)	(6)
Total Stockholders Equity	16,297	12,130
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 38,444	$ 30,734

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, 2008	2007	2006
	($ in millions, except per share data)		
REVENUES:			
Natural gas and oil sales	$ 7,858	$ 5,624	$ 5,619
Natural gas and oil marketing sales	3,598	2,040	1,577
Service operations revenue	173	136	130
Total Revenues	11,629	7,800	7,326
OPERATING COSTS:			
Production expenses	889	640	490
Production taxes	284	216	176
General and administrative expenses	377	243	139
Natural gas and oil marketing expenses	3,505	1,969	1,522
Service operations expense	143	94	68
Natural gas and oil depreciation, depletion and amortization	1,970	1,835	1,359
Depreciation and amortization of other assets	177	154	104
Impairment of natural gas and oil properties and other fixed assets	2,830		
Employee retirement expense			55
Total Operating Costs	10,175	5,151	3,913
INCOME FROM OPERATIONS	1,454	2,649	3,413
OTHER INCOME (EXPENSE):			
Interest and other income	(11)	15	26
Interest expense	(314)	(406)	(301)
Gain on exchanges or repurchases of Chesapeake debt	237		
Impairment of investments	(180)		
Gain on sale of investments		83	117
Total Other Income (Expense)	(268)	(308)	(158)
INCOME BEFORE INCOME TAXES	1,186	2,341	3,255
INCOME TAX EXPENSE:			
Current	423	29	5
Deferred	40	861	1,247
Total Income Tax Expense	463	890	1,252
NET INCOME	723	1,451	2,003
PREFERRED STOCK DIVIDENDS	(33)	(94)	(89)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(67)	(128)	(10)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 623	$ 1,229	$ 1,904
EARNINGS PER COMMON SHARE:			
Basic	$ 1.16	$ 2.69	$ 4.78

Assuming dilution	$ 1.14	$ 2.62	$ 4.35
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.2925	$ 0.2625	$ 0.23
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	536	456	398
Assuming dilution	545	487	459

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,		
	2008	2007	2006
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME	$ 723	$ 1,451	$ 2,003
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion, and amortization	2,147	1,989	1,463
Deferred income taxes	40	861	1,247
Unrealized (gains) losses on derivatives	(712)	415	(497)
Realized (gains) losses on financing derivatives	38	(92)	(136)
Stock-based compensation	132	84	84
Gain on sale of investments		(83)	(117)
Loss (income) from equity investments	38		(10)
Gain on repurchases or exchanges of Chesapeake senior notes	(237)		
Impairment of natural gas and oil properties and other fixed assets	2,830		
Impairment of investments	180		
Other	(1)	8	3
(Increase) decrease in accounts receivable	(78)	(192)	(22)
(Increase) decrease in inventory and other assets	56	(65)	(126)
Increase (decrease) in accounts payable, accrued liabilities and other	76	430	1,025
Increase (decrease) in current and non-current revenues and royalties due others	4	126	(74)
Cash provided by operating activities	5,236	4,932	4,843
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of natural gas and oil companies, proved and unproved properties, net of cash acquired	(8,472)	(2,961)	(3,960)
Exploration and development of natural gas and oil properties	(6,104)	(5,305)	(3,779)
Additions to other property and equipment	(3,073)	(1,439)	(987)
Additions to investments	(74)	(8)	(554)
Divestitures of proved and unproved properties and leasehold	6,091		
Proceeds from sale of volumetric production payments	1,579	1,089	
Proceeds from sale of compressors	114	188	
Proceeds from sale of drilling rigs and equipment	64	369	244
Proceeds from sale of investments	2	124	159
Acquisition of trucking company, net of cash acquired			(45)
Deposits for acquisitions	(12)	(15)	(22)
Sale of other assets	41	36	2
Cash used in investing activities	(9,844)	(7,922)	(8,942)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	13,291	7,932	8,370
Payments on long-term borrowings	(11,307)	(6,160)	(8,264)
Proceeds from issuance of senior notes, net of offering costs	2,136	1,607	1,755
Proceeds from issuance of common stock, net of offering costs	2,598		1,759
Proceeds from issuance of preferred stock, net of offering costs			558
Cash paid to purchase Chesapeake senior notes	(312)		
Cash paid for common stock dividends	(148)	(115)	(87)
Cash paid for preferred stock dividends	(35)	(95)	(88)
Cash paid for treasury stock	(5)		(86)

Derivative settlements	(167)	(91)	(87)
Net increase (decrease) in outstanding payments in excess of cash balance	330	(98)	70
Cash received from exercise of stock options	9	15	73
Excess tax benefit from stock-based compensation	43	20	88
Other financing costs	(77)	(27)	(19)
Cash provided by financing activities	6,356	2,988	4,042
Net increase (decrease) in cash and cash equivalents	1,748	(2)	(57)
Cash and cash equivalents, beginning of period	1	3	60
Cash and cash equivalents, end of period	$ 1,749	$ 1	$ 3

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 (Continued)

	Years Ended December 31,		
	2008	2007	2006
	($ in millions)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$ 218	$ 315	$ 273
Income taxes, net of refunds received	$ 296	$ 55	$
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:			

As of December 31, 2008 2007 and 2006, dividends payable on our common and preferred stock were $50 million, $53 million and $53 million, respectively.

In 2008, 2007 and 2006, natural gas and oil properties were adjusted by $13 million, $131 million and $180 million, respectively, for net income tax liabilities related to acquisitions.

During 2008, 2007 and 2006, natural gas and oil properties were adjusted by ($4) million, $97 million and $85 million, respectively, as a result of an increase (decrease) in accrued exploration and development costs.

During 2008, 2007, and 2006, other property and equipment were adjusted by $125 million, $3 million and $11 million, respectively, as a result in an increase (decrease) in accrued costs.

We recorded non-cash asset additions to net natural gas and oil properties of $10 million, $29 million and $23 million in 2008, 2007 and 2006, respectively, for asset retirement obligations.

In 2008, holders of certain of our contingent convertible senior notes exchanged or converted their senior notes for shares of common stock in privately negotiated exchanges as summarized below ($ in millions):

Contingent Convertible Senior Notes	Principal Amount	Number of Common Shares
2.75% due 2035	$239	8,841,526
2.50% due 2037	272	8,416,865
2.25% due 2038	254	6,654,821
	$765	23,913,212

In 2008, we issued 1,677,000 shares of common stock, valued at $34 million for the purchase of leasehold and unproved properties pursuant to an acquisition shelf registration statement.

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 (Continued)

In 2008, 2007 and 2006, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares	Type of Transaction
2008	5.0% (Series 2005B)	3,654,385	10,443,642	Exchange
	4.5%	891,100	2,227,750	Exchange
	4.125%	29	1,743	Conversion
			12,673,135	
2007	5.0% (Series 2005)	4,595,000	19,283,311	Exchange
	6.25%	2,156,184	17,367,823	Exchange
	6.25%	48	344	Conversion
	4.125%	3	180	Conversion
			36,651,658	
2006	5.0% (Series 2003)	987,321	6,113,009	Exchange
	5.0% (Series 2003)	38,625	235,447	Conversion
	4.125%	85,995	5,420,720	Exchange
	6.0%	99,310	482,694	Conversion
			12,251,870	

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

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Years Ended December 31,		
	2008	2007	2006
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 960	$ 1,958	$ 1,577
Issuance of 6.25% mandatory convertible preferred stock			575
Exchange of common stock for 3,654,385, 0 and 0 shares of 5.00% preferred stock (Series 2005B)	(366)		
Exchange of common stock for 891,100, 0 and 0 shares of 4.50% preferred stock	(89)		
Exchange of common stock for 0, 4,595,000 and 0 shares of 5.00% preferred stock (Series 2005)		(459)	
Exchange of common stock for 0, 2,156,232 and 0 shares of 6.25% preferred stock		(539)	
Exchange of common stock for 29, 3 and 85,995 shares of 4.125% preferred stock			(86)
Exchange of common stock for 0, 0 and 1,025,946 shares of 5.00% preferred stock (Series 2003)			(103)
Exchange of common stock for 0, 0 and 99,310 shares of 6.00% preferred stock			(5)
Balance, end of period	505	960	1,958
COMMON STOCK:			
Balance, beginning of period	5	5	4
Issuance of 51,750,000, 0 and 58,750,000 shares of common stock	1		1
Issuance of 1,677,000, 0 and 0 shares of common stock for the purchase of leasehold and unproved properties			
Issuance of 0, 0 and 1,375,989 shares of common stock for the purchase of Chaparral Energy, Inc. common stock			
Exchange of 12,673,135, 36,651,658 and 12,251,870 shares of common stock for preferred stock			
Exchange of 23,913,212, 0 and 0 shares of common stock for convertible notes			
Exercise of stock options			
Restricted stock grants			
Balance, end of period	6	5	5
PAID-IN CAPITAL:			
Balance, beginning of period	7,032	5,873	3,803
Issuance of common stock	2,697		1,799
Issuance of common stock for the purchase of leasehold and unproved properties	34		
Issuance of common stock for the purchase of Chaparral Energy, Inc. common stock			40
Exchange of 23,913,212, 0 and 0 shares of common stock for convertible notes	480		
Exchange of 12,673,135, 36,651,658 and 12,251,870 shares of common stock for preferred stock	454	998	193
Stock-based compensation	188	129	100
Adoption of SFAS 123(R)			(89)
Common stock offering expenses	(101)		(58)
Exercise of stock options	8	15	73
Release of 0, 0 and 6,500,000 shares from treasury stock upon exercise of stock options			(75)
Tax benefit from exercise of stock options and restricted stock	43	20	88
Preferred stock conversion/exchange expenses		(3)	(1)
Balance, end of period	10,835	7,032	5,873

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY (Continued)

	Years Ended December 31,		
	2008	2007	2006
		($ in millions)	
RETAINED EARNINGS:			
Balance, beginning of period	4,150	2,913	1,101
Net income	723	1,451	2,003
Dividends on common stock	(158)	(121)	(96)
Dividends on preferred stock	(21)	(89)	(95)
Adoption of FIN48		(4)	
Balance, end of period	4,694	4,150	2,913
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(11)	528	(195)
Hedging activity	297	(520)	809
Marketable securities activity	(19)	(19)	(86)
Balance, end of period	267	(11)	528
UNEARNED COMPENSATION:			
Balance, beginning of period			(89)
Adoption of SFAS 123(R)			89
Balance, end of period			
TREASURY STOCK COMMON:			
Balance, beginning of period	(6)	(26)	(26)
Purchase of 159,430, 0 and 2,707,471 shares of treasury stock	(4)		(86)
Release of 0, 0 and 6,500,000 shares upon exercise of stock options			75
Release of 2,975, 666,186 and 361,280 shares for company benefit plans		20	11
Balance, end of period	(10)	(6)	(26)
TOTAL STOCKHOLDERS EQUITY	$ 16,297	$ 12,130	$ 11,251

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2008	2007	2006
	($ in millions)		
Net Income	$ 723	$ 1,451	$ 2,003
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of $113 million, ($56) million and $1.033 billion, respectively	186	(92)	1,711
Reclassification of (gain) loss on settled contracts, net of income taxes of $35 million, ($308) million and ($426) million, respectively	55	(504)	(706)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $34 million, $46 million and ($116) million, respectively	56	76	(195)
Unrealized gain on marketable securities, net of income taxes of ($12) million, ($11) million and ($8) million, respectively	(19)	(19)	(13)
Reclassification of gain on sales of investments, net of income taxes of $0, $0 and ($46) million, respectively			(73)
Comprehensive income	$ 1,001	$ 912	$ 2,727

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

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

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake include the accounts of our direct and indirect wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated.

Accounting Estimates

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

Cash Equivalents

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

Accounts Receivable

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

Accounts receivable consists of the following components:

	December 31, 2008	December 31, 2007
	($ in millions)	
Natural gas and oil sales	$ 738	$ 798
Joint interest	424	175
Service operations	20	10
Related parties (a)		18
Other	154	81
Allowance for doubtful accounts	(12)	(8)
Total accounts receivable	$ 1,324	$ 1,074

(a) See Note 6 for discussion of related party transactions.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Natural Gas and Oil Properties

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities (see Note 10). Capitalized costs are amortized on a composite unit-of-production method based on proved natural gas and oil reserves. Estimates of our proved reserves as of December 31, 2008 were prepared by Chesapeake s internal staff. Approximately 76% of these proved reserves estimates (by volume) at year-end 2008 were audited by independent engineering firms. In addition, our internal engineers review and update our reserves on a quarterly basis. The average composite rates used for depreciation, depletion and amortization were $2.34 per mcfe in 2008, $2.57 per mcfe in 2007 and $2.35 per mcfe in 2006.

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

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

We review the carrying value of our natural gas and oil 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. As of December 31, 2008, capitalized costs of natural gas and oil properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in a write-down in the carrying value of natural gas and oil properties of $2.8 billion. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Based on spot prices for natural gas and oil as of December 31, 2008, these cash flow hedges increased the full-cost ceiling by $1.024 billion, thereby reducing the ceiling test write-down by the same amount. Our qualifying cash flow hedges as of December 31, 2008, which consisted of swaps and collars, covered 362 bcfe, 98 bcfe and 24 bcfe in 2009, 2010 and 2011, respectively. Our natural gas and oil hedging activities are discussed in Note 9 of these consolidated financial statements.

Two primary factors impacting the ceiling test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, natural gas and oil prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Other Property and Equipment

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

	December 31, 2008	December 31, 2007	Useful Life (in years)
	($ in millions)		
Natural gas gathering systems and treating plants	$ 2,717	$ 1,135	20
Buildings and improvements	681	421	15 39
Drilling rigs and equipment	430	106	15
Natural gas compressors	184	63	20
Other	482	327	2 7
Land	832	395	
Total	$ 5,326	$ 2,447	

Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. For 2008, we recorded an impairment of $30 million associated with certain of our midstream assets.

Investments

Investments in securities are accounted for under the equity method in circumstances where we are deemed to exercise significant influence over the operating and investing policies of the investee but do not have control. Under the equity method, we recognize our share of the investee s earnings in our consolidated statements of operations. Investments in securities not accounted for under the equity method are accounted for under the cost

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

method. Investments in marketable equity securities accounted for under the cost method have been designated as available for sale and, as such, are recorded at fair value. We evaluate our investments for impairment in value and recognize a charge to earnings when any identified impairment is judged to be other than temporary. For 2008, we recorded an impairment of $180 million associated with certain of our investments. See Note 12 for further discussion of investments.

Capitalized Interest

During 2008, 2007 and 2006, interest of approximately $464 million, $269 million and $179 million, respectively, was capitalized on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings.

Accounts Payable and Accrued Liabilities

Included in accounts payable at December 31, 2008 and 2007, respectively, are liabilities of approximately $480 million and $150 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Other accrued liabilities include $258 million and $262 million of accrued drilling costs as of December 31, 2008 and 2007, respectively.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and costs associated with our revolving bank credit facility and hedging facilities. The remaining unamortized debt issue costs at December 31, 2008 and 2007 totaled $157 million and $138 million, respectively, and are being amortized over the life of the senior notes, revolving credit facilities or hedging facilities.

Asset Retirement Obligations

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

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

Revenue Recognition

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

Natural Gas Imbalances. We follow the sales method of accounting for our natural gas revenue whereby we recognize sales revenue on all natural gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining natural gas reserves on the underlying properties. The natural gas imbalance net position at December 31, 2008 and 2007 was a liability of $6 million and $4 million, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Hedging

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

We have established the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

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

Stock-Based Compensation

Chesapeake s stock based compensation programs consist of restricted stock and stock options issued to employees and non-employee directors. On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment* (SFAS 123(R)), to account for stock-based compensation. SFAS 123(R) requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the fair value at grant date of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

unrecognized compensation expense, based on the fair value at the original grant date, is recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense based on the fair value on the date of grant or modification is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. To the extent compensation cost relates to employees directly involved in natural gas and oil exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expenses or production expenses.

Prior to the adoption of SFAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated. Upon adoption of SFAS 123(R), we eliminated $89 million of unearned compensation cost and reduced additional paid-in capital by the same amount on our consolidated balance sheet.

For the years ended December 31, 2008, 2007 and 2006, we recorded the following stock-based compensation ($ in millions):

	2008	2007	2006
Production expenses	$ 30	$ 19	$ 7
General and administrative expenses	85	57	27
Service operations expense	6	3	
Natural gas and oil marketing expenses	11	5	
Natural gas and oil properties	109	68	23
Employee retirement expense			51
Total	$ 241	$ 152	$ 108

SFAS 123(R) also requires cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock (excess tax benefits) to be classified as financing cash inflows in our statements of cash flows. Accordingly, for the years ended December 31, 2008, 2007 and 2006, we reported $43 million, $20 million and $88 million, respectively, of excess tax benefits from stock-based compensation as cash provided by financing activities on our statements of cash flows.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2007 and 2006 to conform to the presentation used for the 2008 consolidated financial statements.

2. Net Income Per Share

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the years ended December 31, 2008, 2007 and 2006, the following securities and associated adjustments to net income comprised of dividends and loss on conversions/exchanges were not included in the calculation of diluted EPS, as the effect was antidilutive ($ in millions):

	2008	
	Shares	**Net Income Adjustments**
Common stock equivalent of our preferred stock outstanding:		
4.50% convertible preferred stock	5,795,396	$ 12
5.00% (series 2005) convertible preferred stock	19,443	$
5.00% (series 2005B) convertible preferred stock	5,367,289	$ 10
6.25% mandatory convertible preferred stock	1,237,770	$ 2
Common stock equivalent of our preferred stock outstanding prior to conversion:		
4.50% convertible preferred stock	1,135,906	$ 14
5.00% (series 2005B) convertible preferred stock	3,917,224	$ 62

	2007	
	Shares	**Net Income Adjustments**
Common stock equivalent of our preferred stock outstanding prior to conversion:		
5.00% (series 2005) convertible preferred stock	16,158,815	$ 76
6.25% mandatory convertible preferred stock	13,982,602	$ 99

	2006	
	Shares	**Net Income Adjustments**
Common stock equivalent of our preferred stock outstanding prior to conversion:		
4.125% convertible preferred stock	2,090,292	$ 9

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A reconciliation for the years ended December 31, 2008, 2007 and 2006 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
For the Year Ended December 31, 2008:			
Basic EPS:			
Income available to common shareholders	$ 623	536	$ 1.16
Effect of Dilutive Securities			
Effect of contingent convertible senior notes outstanding during the period		1	
Employee stock options		2	
Restricted stock		6	
Diluted EPS Income available to common shareholders and assumed conversions	$ 623	545	$ 1.14
For the Year Ended December 31, 2007:			
Basic EPS:			
Income available to common shareholders	$ 1,229	456	$ 2.69
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% (Series 2005B) convertible preferred stock		15	
Common shares assumed issued for 6.25% mandatory convertible preferred stock		1	
Employee stock options		4	
Restricted stock		3	
Preferred stock dividends	47		
Diluted EPS income available to common shareholders and assumed conversions	$ 1,276	487	$ 2.62
For the Year Ended December 31, 2006:			
Basic EPS:			
Income available to common shareholders	$ 1,904	398	$ 4.78
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% (Series 2005) convertible preferred stock		18	
Common shares assumed issued for 5.00% (Series 2005B) convertible preferred stock		15	
Common shares assumed issued for 6.25% mandatory convertible preferred stock		9	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion, 5.00% (Series 2003) convertible preferred stock		2	

Employee stock options		6	
Restricted stock		3	
Loss on redemption of preferred stock	3		
Preferred stock dividends	87		
Diluted EPS income available to common shareholders and assumed conversions	$ 1,994	459	$ 4.35

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following at December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
	($ in millions)	
7.5% Senior Notes due 2013	$ 364	$ 364
7.625% Senior Notes due 2013	500	500
7.0% Senior Notes due 2014	300	300
7.5% Senior Notes due 2014	300	300
7.75% Senior Notes due 2015 (a)		300
6.375% Senior Notes due 2015	600	600
6.625% Senior Notes due 2016	600	600
6.875% Senior Notes due 2016	670	670
6.25% Euro-denominated Senior Notes due 2017 (b)	835	876
6.5% Senior Notes due 2017	1,100	1,100
6.25% Senior Notes due 2018	600	600
7.25% Senior Notes due 2018	800	
6.875% Senior Notes due 2020	500	500
2.75% Contingent Convertible Senior Notes due 2035 (c)	451	690
2.5% Contingent Convertible Senior Notes due 2037 (c)	1,378	1,650
2.25% Contingent Convertible Senior Notes due 2038 (c)	1,126	
Revolving bank credit facility	3,474	1,950
Midstream revolving bank credit facility	460	
Discount on senior notes	(85)	(105)
Interest rate derivatives (d)	211	55
Total notes payable and long-term debt	$ 14,184	$ 10,950

(a) The 7.75% Senior Notes due 2015 were redeemed on July 7, 2008. In connection with the transaction we recorded a $31 million loss (which consisted of a $12 million premium and the write-off of $19 million in various charges associated with the notes).

(b) The principal amount shown is based on the dollar/euro exchange rate of $1.3919 to 1.00 and $1.4603 to 1.00 as of December 31, 2008 and 2007, respectively. See Note 9 for information on our related cross currency swap.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the fourth quarter of 2008, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the first quarter of 2009 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. We will pay contingent interest on the convertible

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$ 48.81	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.47	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(d) See Note 9 for further discussion related to these instruments.

No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

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

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. As of December 31, 2007, our obligations under our outstanding senior notes and contingent convertible notes were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned restricted subsidiaries, other than minor subsidiaries, on a senior unsecured basis. In October 2008, we restructured our non-Appalachian midstream operations, as described below. As a result, our wholly-owned midstream subsidiaries having significant assets and operations do not presently guarantee our outstanding senior notes.

We have a $3.5 billion syndicated revolving bank credit facility which matures in November 2012. As of December 31, 2008, we had $3.474 billion in outstanding borrowings under our facility and utilized approximately $15 million of the facility for various letters of credit. To ensure that our revolving bank credit facility could be fully utilized in these turbulent economic times, we borrowed the remaining capacity under our facility in the third quarter and invested the cash proceeds in short-term highly liquid securities. As a result, on December 31, 2008, we had cash and cash equivalents on hand of approximately $1.749 billion. All 36 lenders that participate in our revolving bank credit facility fully funded their commitment, with the exception of Lehman Brothers Commercial Bank, a subsidiary of Lehman Brothers Holdings Inc., which did not fund its $11 million share of the advance. See *Concentration of Credit Risk* in Note 9.

Borrowings under our facility are secured by certain producing natural gas and oil properties and bear interest at our option at either (i) the greater of the reference rate of Union Bank of California, N.A. or the federal

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), plus a margin that varies from 0.75% to 1.50% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently, the commitment fee rate is 0.20% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.43 to 1 and our indebtedness to EBITDA ratio was 2.43 to 1 at December 31, 2008. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration , if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

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

On October 16, 2008, we closed a new secured revolving bank credit facility for our non-Appalachian midstream operations, which have recently been restructured under a new unrestricted subsidiary, Chesapeake Midstream Partners, L.P. (CMP) and its operating subsidiary, Chesapeake Midstream Operating, L.L.C. (CMO). Twelve financial institutions are in the facility bank group. The facility matures in October 2013, has initial availability of $460 million and may be expanded up to $750 million at CMO s option, subject to additional bank participation. CMO is utilizing the facility to fund capital expenditures associated with building additional natural gas gathering and other systems associated with our drilling program and for general corporate purposes related to our midstream operations. As of December 31, 2008, we had $460 million in outstanding borrowings under the midstream credit facility.

The midstream credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMP and its subsidiaries to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 2.50 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 2.59 to 1 and our EBITDA to interest expense coverage ratio was 9.36 to 1 at December 31, 2008. If CMP or its subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMP and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Contingencies and Commitments

Litigation

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

On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of $404 million, consisting of $134 million in compensatory damages and $270 million in punitive damages. The jury found fraudulent conduct by the defendants with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions. The defendants appealed the judgment and on May 22, 2008, the West Virginia Supreme Court of Appeals refused to hear the appeal. On October 22, 2008, the parties in the *Tawney* matter entered into a settlement agreement providing for the establishment of a settlement fund of $380 million. The Circuit Court for Roane County, West Virginia approved the settlement following a fairness hearing on November 22, 2008, and entered an order to discharge the judgment on January 21, 2009. Chesapeake s share of the settlement fund was approximately $41 million, which amount had previously been fully reserved. The Circuit Court retains continuing jurisdiction over the case during the claims administration process in which the settlement amount is distributed to the members of the plaintiff class.

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

Employment Agreements with Officers

Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and other executive officers, which provide for annual base salaries, various benefits and eligibility for bonus compensation. The agreement with the chief executive officer has a term of five years commencing December 31, 2008 and contains a cap on cash salary and bonus compensation for the next five years at 2008 levels. The term of the agreement is automatically extended for one additional year on each December 31 unless the company provides 30 days notice of non-extension. In the event of termination of employment without cause, the chief executive officer s base compensation (defined as base salary plus bonus compensation received during the preceding 12 months) and benefits would continue during the remaining term of the agreement. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation upon the happening of certain events following a change of control. The agreement further provides that any stock-based awards held by the chief executive officer and deferred compensation will immediately become 100% vested upon termination of employment without cause, incapacity, death or retirement at or after age 55. The agreement also provides for a one-time $75 million well cost incentive award with a five-year clawback (see Note 6 for discussion of related party transactions). The agreements with the chief

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operating officer, chief financial officer and other executive officers expire on September 30, 2009. These agreements provide for the continuation of salary for one year in the event of termination of employment without cause or death and, in the event of a change of control, a payment in the amount of two times the executive officer s base compensation. These executive officers are entitled to continue to receive compensation and benefits for 180 days following termination of employment as a result of incapacity. Any stock-based awards held by such executive officers will immediately become 100% vested upon termination of employment without cause, a change of control, death, or retirement at or after age 55.

Environmental Risk

Due to the nature of the natural gas and oil business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a contingent liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at December 31, 2008.

Rig Leases

In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 83 drilling rigs and related equipment for $677 million and entered into a master lease agreement under which we agreed to lease the rigs from the buyer for initial terms of seven to ten years for lease payments of approximately $95 million annually. The lease obligations are guaranteed by Chesapeake and its other material restricted subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss will be amortized to service operations expense over the lease term. Under the rig leases, we can exercise an early purchase option after six or seven years or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic lease equal to the fair market rental value of the rigs as determined at the time of renewal. As of December 31, 2008, Chesapeake s drilling subsidiaries had committed to acquire 23 rigs and had incurred costs of $64 million as of that date. The total remaining cost of the rigs is estimated to be approximately $267 million. Our intent is to sell and lease back those rigs as they are delivered if acceptable leasing arrangements are available to us.

Compressor Leases

In 2007 and 2008, our compression subsidiary sold a significant portion of its existing compressor fleet, consisting of 1,443 compressors, for $303 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from seven to ten years for aggregate lease payments of approximately $37 million annually. The lease obligations are guaranteed by Chesapeake and its other material restricted subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss will be amortized to natural gas and oil marketing expenses over the lease term. Under the leases, we can exercise an early purchase option after six to nine years or we can purchase the compressors at expiration of the lease for the

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

fair market value at the time. In addition, we have the option to renew the lease for negotiated new terms at the expiration of the lease. As of December 31, 2008, approximately 625 new compressors are on order for approximately $240 million and our intent is to sell and lease back those compressors as they are delivered if acceptable leasing arrangements are available to us.

Future operating lease obligations related to rigs, compressors and other equipment or property are not recorded in the accompanying consolidated balance sheets. As of December 31, 2008, minimum future lease payments were as follows ($ in millions):

	Rigs	Compressors	Other	Total
2009	$ 94	$ 40	$ 8	$ 142
2010	95	34	5	134
2011	95	34	3	132
2012	96	36	2	134
2013	97	39	1	137
After 2013	143	125		268
Total	$ 620	$ 308	$ 19	$ 947

Rent expense, including short-term rentals, for the years ended December 31, 2008, 2007 and 2006 was $133 million, $81 million and $47 million, respectively.

Transportation Contracts

Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from 2009 to 2099. These commitments are not recorded in the accompanying condensed consolidated balance sheets. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter s Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company receives rights to flow natural gas production through pipelines located in highly competitive markets. Excluded from this summary are demand charges for pipeline projects that are currently seeking regulatory approval. The aggregate amounts of such required demand payments as of December 31, 2008 are as follows ($ in millions):

2009	$ 162
2010	183
2011	172
2012	164
2013	150
After 2013	735
Total	$ 1,566

Drilling Contracts

We have contracts with various drilling contractors to use 40 drilling rigs with terms of one to three years. These commitments are not recorded in the accompanying consolidated balance sheets. Minimum future commitments as of December 31, 2008 are as follows ($ in millions):

2009	$ 146
2010	79
2011	44
2012	7
After 2012	
Total	$ 276

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Natural Gas and Oil Purchase Obligations

Our marketing segment regularly commits to purchase natural gas from other owners in our properties and such commitments typically are short term in nature. We have also committed to purchase natural gas and oil associated with volumetric production payment transactions. The purchase commitments extend over 11 to 15 year terms based on market prices at the time of production, and the purchased natural gas and oil will be resold. The obligations are as follows:

	Mmcfe
2009	68,238
2010	60,723
2011	53,694
2012	48,069
2013	43,477
After 2013	181,574
Total	455,775

Other Commitments

We own a 49% interest in Mountain Drilling Company, a company that specializes in hydraulic drilling rigs which are designed for drilling in urban areas. Chesapeake has an agreement to lend Mountain Drilling Company up to $32 million through December 31, 2009. At December 31, 2008, Mountain Drilling owed Chesapeake $19 million under this agreement.

We invested in Ventura Refining and Transmission LLC in early 2007 and today own a 25% interest. There were no refineries in western Oklahoma until Ventura opened its refinery in 2006. We have agreed to guarantee various commitments for Ventura, up to $70 million, to support their operating activities. As of December 31, 2008, we had $7 million of outstanding performance guarantees.

5. Income Taxes

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

	Years Ended December 31,		
	2008	2007	2006
	($ in millions)		
Current	$ 423	$ 29	$ 5
Deferred	40	861	1,247
Total	$ 463	$ 890	$ 1,252

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

	Years Ended December 31,		
	2008	2007	2006
	($ in millions)		
Computed expected federal income tax provision	$ 415	$ 819	$ 1,139
State income taxes	32	56	90
Other	16	15	23
	$ 463	$ 890	$ 1,252

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Years Ended December 31, 2008	2007
	($ in millions)	
Deferred tax liabilities:		
Natural gas and oil properties	$ (2,694)	$ (3,760)
Other property and equipment	(281)	(152)
Derivative instruments	(550)	(20)
Volumetric production payments	(943)	(442)
Deferred tax liabilities	(4,468)	(4,374)
Deferred tax assets:		
Net operating loss carryforwards	$ 5	$ 170
Asset retirement obligation	102	91
Investments	117	33
Deferred stock compensation	85	42
Accrued liabilities	22	6
Percentage depletion carryforwards		11
Alternative minimum tax credits		61
Other	16	(5)
Deferred tax assets	347	409
Total deferred tax asset (liability)	$ (4,121)(a)	$ (3,965)
Reflected in accompanying balance sheets as:		
Other current assets	$	$ 1
Current deferred income tax liability	(358)	
Non-current deferred income tax liability	(3,763)	(3,966)
	$ (4,121)	$ (3,965)

(a) In addition to the income tax expense of $463 million, activity during 2008 includes net liabilities of $13 million related to acquisitions and $181 million related to derivative instruments, deferred tax assets for $12 million related to investments and $43 million related to stock-based compensation. These items were not recorded as part of the provision for income taxes. In addition, the activity includes a reduction to deferred tax liabilities of $398 million related to current federal and state income tax liabilities and payments and $48 million related to FIN 48 items.

As of December 31, 2008, we classified $358 million of deferred tax liabilities as current that were attributable to the current portion of derivative assets and other current temporary differences. As of December 31, 2007, we classified $1 million of deferred tax assets as current that were attributable to the current portion of derivative liabilities and other current temporary differences.

At December 31, 2008, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $12 million. Additionally, we had $3 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income. The NOL carryforwards expire from 2019 through 2026. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

The following table summarizes our net operating losses as of December 31, 2008 and any related limitations:

	Total	Limited	Annual Limitation
		($ in millions)	
Net operating loss	$ 12	$ 12	$ 7
AMT net operating loss	$ 3	$ 3	$ 1

As of December 31, 2008, we do not believe that an ownership change has occurred. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109.* FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes.* FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 was effective for fiscal years beginning after December 15, 2006.

Chesapeake adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, Chesapeake recognized a $7 million liability for accrued interest associated with uncertain tax positions which was accounted for as a reduction in the January 1, 2007 balance of retained earnings, net of tax. At the date of adoption and at December 31, 2007, we had approximately $142 million and $133 million, respectively, of unrecognized tax benefits related to alternative minimum tax (AMT) associated with uncertain tax positions. As of December 31, 2008, the amount of unrecognized tax benefits related to regular tax liabilities and AMT associated with uncertain tax positions was $60 million. Of this amount, $48 million is related to regular tax liabilities and $12 million is related to AMT. These unrecognized tax benefits are associated with temporary differences. If these unrecognized tax benefits are disallowed and we are required to pay additional taxes, the reversal of the temporary differences associated with the regular tax liabilities will increase our tax basis which will increase our future tax deductions. Any AMT payments can be utilized as credits against future regular tax

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

liabilities. The uncertain tax positions identified would not have a material effect on the effective tax rate. At December 31, 2008, we had an accrued liability of $3 million for interest related to these uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

	2008	2007
	($ in millions)	
Unrecognized tax benefits at beginning of period	$ 133	$ 142
Additions based on tax positions related to the current year	48	64
Reductions for tax positions of prior years	(120)	(52)
Settlements	(1)	(21)
Unrecognized tax benefits at end of period	$ 60	$ 133

Chesapeake files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. With few exceptions, Chesapeake is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years prior to 2005. The Internal Revenue Service (IRS) completed an examination of Chesapeake s 2005 and 2006 U.S. income tax returns in December 2008. This examination resulted in an additional AMT liability of $1 million. This AMT liability will be utilized as a credit against current regular tax liabilities. The adjustments in the examination did not result in a material change to our financial position, results of operations or cash flows.

6. Related Party Transactions

Since Chesapeake was founded in 1989, our CEO, Aubrey K. McClendon, has acquired working interests in virtually all of our natural gas and oil properties by participating in our drilling activities under the terms of the Founder Well Participation Program (FWPP) and predecessor participation arrangements provided for in Mr. McClendon s employment agreements. Under the FWPP, approved by our shareholders in June 2005, Mr. McClendon may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake s Board of Directors not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the FWPP, which, among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake s working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation.

On December 31, 2008, we entered into a new five-year employment agreement with Mr. McClendon that contained a one-time well cost incentive award to him. The total cost of the award to Chesapeake was $75 million plus employment taxes in the amount of approximately $1 million. We will recognize the incentive award as general and administrative expense over the five-year vesting period for the clawback described below, resulting in an expense of approximately $15 million per year beginning in 2009. In addition to state and federal income tax withholding, similar employment taxes were imposed on Mr. McClendon and withheld from the award. The net incentive award of approximately $44 million can only be applied against costs attributable to interests in company wells acquired by Mr. McClendon or his affiliates under the FWPP. The incentive award is subject to a clawback if, during the initial five-year term of the employment agreement, Mr. McClendon resigns from the company or is terminated for cause by the company. Upon receipt of the company s monthly invoice for joint interest billings in mid-January 2009, Mr. McClendon elected to apply approximately $19 million of the

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

drilling credit against his December 2008 FWPP joint interest billings, leaving $25 million available as a credit against future billings. Based on our current development plans and Mr. McClendon s election under the FWPP to participate with a 2.5% working interest during 2009, the well costs under the FWPP are expected to exceed the amount of the entire FWPP credit in early 2009. We refer you to the discussion of the FWPP and Mr. McClendon s employment agreement contained in our proxy statement for our 2009 annual meeting of shareholders, which discussion is incorporated by reference in Part III of this report.

As disclosed in Note 15, in 2007 and 2006 Chesapeake had revenues of $1.1 billion and $867 million, respectively, from natural gas and oil sales to Eagle Energy Partners I, L.P., a former affiliated entity. We sold our 33% limited partnership interest in Eagle Energy in June 2007.

7. Employee Benefit Plans

Our qualified 401(k) profit sharing plan is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except certain employees of Chesapeake Appalachia, L.L.C. On January 1, 2007, a plan we maintained for the employees of our subsidiary Nomac Drilling Corporation was merged into the Chesapeake plan. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) plan accounts, subject to plan limits and those set by the Internal Revenue Service. Chesapeake matches employee contributions dollar for dollar (subject to a maximum contribution of 15% of the employees annual salary and bonus compensation) with Chesapeake common stock purchased in the open market. For the Nomac plan, the matching percentage was 8% for 2005 through June 2006, and 15% as of July 1, 2006. The company contributed $40 million, $28 million and $18 million to the Chesapeake plan in 2008, 2007 and 2006, respectively, and $2 million to the Nomac plan in 2006.

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

Prior to 2008, we maintained two nonqualified deferred compensation plans, the 401(k) make-up plan and the deferred compensation plan. Effective on January 1, 2008, the deferred compensation plans were merged into the Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan. Prior to 2009, to be eligible to participate in the amended and restated deferred compensation plan, an employee must have received annual compensation (base salary and bonus combined in the prior 12 months) of at least $100,000, had a minimum of one year of service as a company employee and have made the maximum contribution allowable under the 401(k) plan. For employees with at least five years of service as a company employee, the company matches employee contributions to the plan in Chesapeake common stock. On January 1, 2009, the plan was amended to allow for participation for any employee who received compensation (base salary only) of at least $150,000 and had an employment agreement with the company. In addition, the company begins matching employee contributions once the employee has at least three years of service as a company employee.

Chesapeake matches 100% of employee contributions up to 15% of base salary and bonus in the aggregate for the 401(k) plan and the amended and restated deferred compensation plan. We contributed $6 million, $4 million and $2 million to the 401(k) make-up plan during 2008, 2007 and 2006, respectively. The company s non-employee directors are able to defer up to 100% of director fees into the amended and restated deferred

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

compensation plan. The maximum compensation that can be deferred by employees under all company deferred compensation plans, including the Chesapeake 401(k) plan, is a total of 75% of base salary and 100% of performance bonus. Chesapeake made no matching or other contributions to the deferred compensation plan.

Any assets placed in trust by Chesapeake to fund future obligations of the company s nonqualified deferred compensation plans are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the company as to their deferred compensation in the plans.

Chesapeake maintains no post-employment benefit plans except those sponsored by Chesapeake Appalachia, L.L.C. As of December 31, 2006, a total of 188 employees were eligible for these plans. As of January 1, 2007, participation in these plans was limited to union members (135 employees). The Chesapeake Appalachia, L.L.C. benefit plans provide health care and life insurance benefits to eligible employees upon retirement. We account for these benefits on an accrual basis. As of December 31, 2008, the company had accrued approximately $2 million in accumulated post-employment benefit liability.

8. Stockholders Equity, Restricted Stock and Stock Options

Common Stock

The following is a summary of the changes in our common shares outstanding for 2008, 2007 and 2006:

	2008	2007	2006
		(in thousands)	
Shares issued at January 1	511,648	458,601	375,511
Common stock issuances for cash	51,750		58,750
Convertible note conversions/exchanges	23,913		
Preferred stock conversions/exchanges	12,673	36,652	12,252
Restricted stock issuances (net of forfeitures)	4,708	14,268	3,743
Stock option exercises	1,584	2,127	6,969
Common stock issued for the purchase of leasehold and unproved properties	1,677		
Common stock issued for the purchase of Chaparral Energy, Inc. common stock			1,376
Shares issued at December 31	607,953	511,648	458,601

Contingent Convertible Senior Notes

In 2008, holders of certain of our contingent convertible senior notes exchanged or converted their senior notes for shares of common stock in privately negotiated exchanges as summarized below ($ in millions):

Contingent Convertible Senior Notes	Principal Amount	Number of Common Shares
2.75% due 2035	$239	8,841,526
2.50% due 2037	272	8,416,865
2.25% due 2038	254	6,654,821

	$765	23,913,212

The difference between the face value of the notes that were exchanged and the fair value of the common stock issued resulted in a gain of $268 million on the cancellation of indebtedness.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Preferred Stock

The following is a summary of the changes in our preferred shares outstanding for 2008, 2007 and 2006:

	6.00%	5.00% (2003)	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
				(in thousands)			
Shares outstanding at January 1, 2008			3	5	3,450	5,750	144
Conversion/exchange of preferred for common stock					(891)	(3,654)	
Shares outstanding at December 31, 2008			3	5	2,559	2,096	144
Shares outstanding at January 1, 2007			3	4,600	3,450	5,750	2,300
Conversion/exchange of preferred for common stock				(4,595)			(2,156)
Shares outstanding at December 31, 2007			3	5	3,450	5,750	144
Shares outstanding at January 1, 2006	99	1,026	89	4,600	3,450	5,750	
Preferred stock issuances							2,300
Conversion/exchange of preferred for common stock	(99)	(1,026)	(86)				
Shares outstanding at December 31, 2006			3	4,600	3,450	5,750	2,300

In 2008, 2007 and 2006, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares	Type of Transaction
2008	5.0% (Series 2005B)	3,654,385	10,443,642	Exchange
	4.5%	891,100	2,227,750	Exchange
	4.125%	29	1,743	Conversion
			12,673,135	
2007	5.0% (Series 2005)	4,595,000	19,283,311	Exchange
	6.25%	2,156,184	17,367,823	Exchange
	6.25%	48	344	Conversion
	4.125%	3	180	Conversion
			36,651,658	
2006	5.0% (Series 2003)	987,321	6,113,009	Exchange
	5.0% (Series 2003)	38,625	235,447	Conversion

4.125%	85,995	5,420,720	Exchange
6.0%	99,310	482,694	Conversion
		12,251,870	

In connection with the exchanges and conversions noted above, we recorded losses of $67 million, $128 million and $10 million in 2008, 2007 and 2006, respectively. In general, the loss is equal to the excess of the fair value of all common stock exchanged over the fair value of the common stock issuable pursuant to the original terms of the preferred stock.

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Dividends on our outstanding preferred stock are payable quarterly in cash or, with respect to our 6.25% mandatory convertible preferred stock and our 4.50% cumulative convertible preferred stock, we may pay dividends in cash, common stock or a combination thereof. Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2008:

Preferred Stock Series	Issue Date	Liquidation Preference per Share	Holder s Conversion Right	Conversion Rate	Conversion Price	Company s Conversion Right From	Company s Market Conversion Trigger
6.25% Mandatory Convertible (a)	June/July 2006	$ 250	Any time	7.1745	$ 34.8456	Any time	$ 52.2684(b)
5.00% (Series 2005) Cumulative Convertible	April 2005	$ 100	Any time	3.8887	$ 25.7154	April 15, 2010	$ 33.4300(c)
4.50% Cumulative Convertible	September 2005	$ 100	Any time	2.2648	$ 44.1538	September 15, 2010	$ 57.3999(c)
5.00% (Series 2005B) Cumulative Convertible	November 2005	$ 100	Any time	2.5612	$ 39.0442	November 15, 2010	$ 50.7575(c)
4.125% Cumulative Convertible	March/April 2004	$ 1,000	Market price >$21.61	60.1569	$ 16.6232	March 15, 2009	$ 21.6100(c)

(a) Each share converts automatically on June 15, 2009 into 7.1745 to 8.6095 shares of common stock, depending on the common stock market price at the time.

(b) Convertible at initial conversion rate plus cash equal to present value of future dividends to June 15, 2009.

(c) Convertible at the company s option if the company s common stock equals or exceeds the trigger price for a specified time period or after the conversion date indicated above if the number of shares of preferred stock outstanding are less than minimum levels provided in the certificates of designation.

Stock-Based Compensation Plans

Under Chesapeake s Long Term Incentive Plan, restricted stock, stock options, stock appreciation rights, performance shares and other stock awards may be awarded to employees, directors and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares of common stock available for awards under the plan may not exceed 25,000,000 shares. The maximum period for exercise of an option or stock appreciation right may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option or stock appreciation right on the date of grant. Awards granted under the plan become vested at dates or upon the satisfaction of certain performance or other criteria determined by a committee of the Board of Directors. No awards may be granted under this plan after September 30, 2014. This plan has been approved by our shareholders. There were 87,500, 87,500 and 75,000 shares of restricted stock issued to our directors from this plan in 2008, 2007 and 2006, respectively. Additionally, there were 4.5 million, 14.7 million and 2,610 restricted shares issued, net of forfeitures to employees and consultants during 2008, 2007 and 2006, respectively from this plan. As of December 31, 2008, there were 5,762,679 shares remaining available for issuance under the plan.

Under Chesapeake s 2003 Stock Incentive Plan, restricted stock and incentive and nonqualified stock options to purchase our common stock may be awarded to employees and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares available for awards under the plan may not exceed 10,000,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option on the date of grant. Restricted stock and options granted become vested at dates determined by a committee of the Board of Directors. No awards may be granted under this plan after April 14, 2013. This plan has been approved by our shareholders. There were 0.2 million, 0.2 million and 4.0 million restricted shares, net of forfeitures, issued during 2008, 2007 and 2006, respectively, from this plan. As of December 31, 2008, there were 213,302 shares remaining available for issuance under the plan.

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Under Chesapeake s 2003 Stock Award Plan for Non-Employee Directors, 10,000 shares of Chesapeake s common stock are awarded to each newly appointed non-employee director on his or her first day of service. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued may not exceed 100,000 shares. This plan has been approved by our shareholders. In each of 2008, 2007 and 2006, 10,000 shares of common stock were awarded to new directors from this plan. As of December 31, 2008, there were 50,000 shares remaining available for issuance under this plan.

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

Name of Plan	Eligible Participants	Type of Options	Shares Covered	Shareholder Approved	Outstanding Options at December 31, 2008
2002 and 2001 Stock Option Plans	Employees and consultants	Incentive and nonqualified	3,000,000/ 3,200,000	Yes	879,523
2002 and 2001 Nonqualified Stock Option Plans	Employees and consultants	Nonqualified	4,000,000/ 3,000,000	No	977,732
2000 and 1999 Employee Stock Option Plans	Employees and consultants	Nonqualified	3,000,000 (each plan)	No	335,864
1996 and 1994 Stock Option Plans	Employees and consultants	Incentive and nonqualified	6,000,000/ 4,886,910	Yes	153,052

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is generally four years from the date of grant for employees and three years for non-employee directors. To the extent amortization of compensation cost relates to employees directly involved in acquisition, exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized in general and administrative expense or production expense. Note 1 details the accounting for our stock-based compensation expense in 2008, 2007 and 2006. As of December 31, 2005, the unamortized balance of unearned compensation recorded as a reduction of stockholders equity was $89 million. Upon adoption of SFAS 123(R) in January 2006, we eliminated the unamortized balance of unearned compensation in stockholders equity ($89 million) and reduced additional paid-in capital by the same amount on our consolidated balance sheet.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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A summary of the status of the unvested shares of restricted stock and changes during 2008, 2007 and 2006 is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2008	19,688,759	$ 32.42
Granted	6,800,027	51.14
Vested	(3,942,326)	28.27
Forfeited	(924,258)	37.33
Unvested shares as of December 31, 2008	21,622,202	$ 38.85
Unvested shares as of January 1, 2007	7,074,761	$ 25.85
Granted	15,560,570	34.25
Vested	(2,255,384)	24.34
Forfeited	(691,188)	33.29
Unvested shares as of December 31, 2007	19,688,759	$ 32.42
Unvested shares as of January 1, 2006	5,805,210	$ 18.38
Granted	4,392,270	31.77
Vested	(2,818,249)	19.78
Forfeited	(304,470)	25.04
Unvested shares as of December 31, 2006	7,074,761	$ 25.85

The aggregate intrinsic value of restricted stock vested during 2008 was approximately $211 million based on the stock price at the time of vesting.

As of December 31, 2008, there was $639 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.61 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the years ended December 31, 2008, 2007 and 2006, we recognized excess tax benefits related to restricted stock of $28 million, $5 million and $4 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward s Resignation Agreement provided for the immediate vesting of all of his unvested equity awards, which consisted of options to purchase 724,615 shares of Chesapeake s common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock. As a result of this vesting, we incurred an expense of $55 million in 2006.

Stock Options

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides information related to stock option activity for 2008, 2007 and 2006:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value (a) ($ in millions)
Outstanding at January 1, 2008	4,445,455	$ 7.55		
Exercised	(1,639,401)	6.54		$ 66
Forfeited/ Canceled	(3,633)	15.26		
Outstanding at December 31, 2008	2,802,421	$ 8.13	3.59	$ 23
Exercisable at December 31, 2008	2,801,796	$ 8.13	3.59	$ 23
Shares authorized for future grants	5,762,679			
Fair value of options granted during period	$			
Outstanding at January 1, 2007	6,605,703	$ 7.43		
Exercised	(2,146,640)	7.16		$ 61
Forfeited/ Canceled	(13,608)	9.90		
Outstanding at December 31, 2007	4,445,455	$ 7.55	4.37	$ 141
Exercisable at December 31, 2007	4,422,519	$ 7.51	4.36	$ 140
Shares authorized for future grants	2,460,562			
Fair value of options granted during period	$			
Outstanding at January 1, 2006	20,256,013	$ 6.14		
Exercised	(13,494,835)	5.34		$ 352
Forfeited/ Canceled	(155,475)	20.22		
Outstanding at December 31, 2006	6,605,703	$ 7.43	5.36	$ 143
Exercisable at December 31, 2006	5,337,153	$ 7.02	5.14	$ 118
Shares authorized for future grants	6,719,642			
Fair value of options granted during period	$			

(a)

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

As of December 31, 2008, unrecognized compensation cost related to unvested stock options was not significant.

During the years ended December 31, 2008, 2007 and 2006, we recognized excess tax benefits related to stock options of $15 million, $15 million and $84 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes information about stock options outstanding at December 31, 2008:

Range of		Outstanding Options			Options Exercisable	
Exercise Prices		Number Outstanding	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Number Exercisable	Weighted-Avg. Exercise Price
$ 0.94	$ 4.00	213,689	1.10	$ 3.27	213,689	$ 3.27
5.20	5.20	331,009	3.56	5.20	331,009	5.20
5.35	5.89	140,150	2.25	5.55	140,150	5.55
6.11	6.11	490,114	2.79	6.11	490,114	6.11
6.40	7.74	96,617	2.97	6.90	96,617	6.90
7.80	7.80	480,578	4.00	7.80	480,578	7.80
7.86	10.01	124,987	3.53	8.52	124,987	8.52
10.08	10.08	555,058	4.34	10.08	555,058	10.08
10.10	15.48	282,719	4.89	13.38	282,094	13.37
16.08	22.49	87,500	6.04	19.74	87,500	19.74
$ 0.94	$22.49	2,802,421	3.59	$ 8.13	2,801,796	$ 8.13

9. Financial Instruments and Hedging Activities

Natural Gas and Oil Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2008, our natural gas and oil derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options, put options and collars. These instruments allow us to predict with greater certainty the effective natural gas and oil 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.

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

For knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For put options, Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. If the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall. If the market price settles above the fixed price of the put option, no payment is due from Chesapeake.

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

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

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

Gains or losses from certain derivative transactions are reflected as adjustments to natural gas and oil sales on the consolidated statements of operations. Realized gains (losses) are included in natural gas and oil sales in the month of related production. 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 natural gas and oil sales. 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 natural gas and oil sales as unrealized gains (losses). The components of natural gas and oil sales for the years ended December 31, 2008, 2007 and 2006 are presented below.

	Years Ended December 31,		
	2008	2007	2006
		($ in millions)	
Natural gas and oil sales	$ 7,069	$ 4,795	$ 3,870
Realized gains (losses) on natural gas and oil derivatives	(8)	1,203	1,254
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	887	(252)	184
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(90)	(122)	311
Total natural gas and oil sales	$ 7,858	$ 5,624	$ 5,619

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The estimated fair values of our natural gas and oil derivative instruments as of December 31, 2008 and 2007 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2008	December 31, 2007
	($ in millions)	
Derivative assets (liabilities) (a):		
Fixed-price natural gas swaps	$ 863	$ (54)
Fixed-price natural gas collars	402	4
Natural gas basis protection swaps	93	151
Fixed-price natural gas knockout swaps	141	108
Natural gas call options	(178)	(230)
Natural gas put options	(39)	
Fixed-price oil swaps	31	(110)
Fixed-price oil knockout swaps	19	(125)
Fixed-price oil cap-swaps	3	(17)
Oil call options	(35)	(96)
Fixed-price oil collars	5	
Estimated fair value	$ 1,305	$ (369)

(a) After adjusting for $736 million and $276 million of unrealized premiums, the cumulative unrealized gain (loss) related to these derivatives as of December 31, 2008 and 2007 was $2.041 billion and ($93) million, respectively.

Based upon the market prices at December 31, 2008, we expect to transfer approximately $345 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of December 31, 2008 are expected to mature by December 31, 2022.

We have six 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 a stated maximum value. Outstanding transactions under each facility are collateralized by certain of our natural gas and oil properties that do not secure any of our other obligations. The value of reserve collateral pledged to each facility is required to be at least 1.3 or 1.5 times the fair value of transactions outstanding under each facility. In addition, we may pledge collateral from our revolving bank credit facility, from time to time, to these facilities to meet any additional collateral coverage requirements. The hedging facilities are subject to a per annum exposure fee, which is assessed quarterly based on the average of the daily negative fair value amounts of the hedges, if any, during the quarter. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate natural gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time. The fair value of outstanding transactions, per annum exposure fees and the scheduled maturity dates are shown below.

	Secured Hedging Facilities (a)					
	#1	#2	#3	#4	#5	#6
	($ in millions)					
Fair value of outstanding transactions, as of December 31, 2008	$ 116	$ 369	$ 37	$ 9	$ 245	$ 94
Per annum exposure fee	1%	1%	0.8%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2013	2020	2012	2012	2012

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(a) Chesapeake Exploration, L.L.C. is the named party to the facilities numbered 1 3 and Chesapeake Energy Corporation is the named party to the facilities numbered 4 6.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within interest expense.

Gains or losses from certain interest rate derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. Realized gains (losses) included in interest expense were $6 million, ($1) million and ($2) million in 2008, 2007 and 2006, respectively. Unrealized gains (losses) included in interest expense were ($85) million, ($40) million and $2 million in 2008, 2007 and 2006, respectively.

As of December 31, 2008, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate (b)	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Interest Rate:						
Swaps						
January 2008 November 2020	$ 750	6.75%	6 mL plus 224 bp	Yes	$	$ 115
Call Options						
February 2009 May 2009	$ 750	6.75%	6 mL plus 224 bp	No	11	(105)
Swaption						
January 2009	$ 250	6.50%	6 mL plus 200 bp	No	3	
Floating to Fixed Interest Rate:						
Swaps						
August 2007 August 2010	$ 825	4.74%	1 3 mL	No		(27)
Collars (a)						
August 2007 August 2010	$ 800	4.52%	6 mL	No		(35)
Swaption						
August 2009	$ 500	2.56%	1 mL	No	5	(10)
					$ 19	$ (62)

(a) The collars have ceiling and floor fixed interest rates of 5.37% and 4.52%, respectively.

(b) Month LIBOR has been abbreviated mL and basis points has been abbreviated bp .

In 2008, we closed interest rate derivatives for gains totaling $110 million of which $30 million was recognized in interest expense. The remaining $80 million was from interest rate derivatives designated as fair value hedges and the settlement amounts received will be amortized as a reduction to interest expense over the remaining term of the related senior notes ranging from five to twelve years.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties will pay Chesapeake 19 million and Chesapeake will pay the counterparties $30 million, which will yield an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($835 million at December 31, 2008) using an exchange rate of $1.3919 to 1.00. The fair value of the cross currency swap is recorded on the consolidated balance sheet as a liability of $77 million at December 31, 2008.

Fair Value of Financial Instruments

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

The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term debt and our convertible preferred stock using primarily quoted market prices. Our carrying amounts for such debt, excluding the impact of interest rate derivatives, at December 31, 2008 and 2007 were $14.0 billion and $10.9 billion, respectively, compared to approximate fair values of $10.5 billion and $11.1 billion, respectively. The carrying amounts for our convertible preferred stock as of December 31, 2008 and 2007 were $505 million and $960 million, respectively, compared to approximate fair values of $294 million and $1.0 billion, respectively.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in both cash and cash equivalents and derivative instruments. On December 31, 2008, our cash and cash equivalents were invested in money market funds with investment grade ratings. A significant portion of these funds was invested at the close of business on September 19, 2008, and is protected under the U.S. Treasury Department s Temporary Guarantee Program. The remaining funds were spread among several counterparties to mitigate risk. The derivative instruments enable us to hedge a portion of our exposure to natural gas and oil price and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers. Recently there have been concerns about the ability of certain counterparties to continue to meet their financial obligations. On December 31, 2008, our commodity and interest rate derivative instruments were spread among 16 counterparties and no single counterparty represented a material credit risk to the company.

On September 15, 2008, Lehman Brothers Holdings Inc. (Lehman) filed for protection under Chapter 11 of the federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Chesapeake and its subsidiaries had certain business relationships with Lehman and its subsidiaries. We believe the Lehman bankruptcy and its potential impact on subsidiaries of Lehman will not have a material adverse effect on Chesapeake or its subsidiaries individually or collectively.

Lehman Brothers Commercial Bank (LBCB), a subsidiary of Lehman, had $75 million of the $3.5 billion in commitments under our revolving bank credit facility. Although LBCB, to date, has not filed for bankruptcy (to our knowledge), LBCB had not funded approximately $11 million of its share of our borrowings under the credit facility as of December 31, 2008 and we have no reason to expect that LBCB will fund borrowings in the future. The loss of up to $75 million in borrowing capacity is not material to us.

Chesapeake was a counterparty with Lehman Brothers Commodity Services Inc. (LBCS), a subsidiary of Lehman, in financial transactions. Specifically, we utilized LBCS as a counterparty to hedge a portion of our natural gas and oil production. The obligations of LBCS are guaranteed by Lehman, and the Lehman bankruptcy filing resulted in an event of default under our ISDA agreement with LBCS allowing us to terminate the ISDA on September 18, 2008, and cancel the outstanding transactions. The potential loss associated with the termination of such transactions is not material to us.

Chesapeake sells natural gas to Eagle Energy Partners 1, LP (Eagle Energy), previously an affiliate of Lehman. Eagle Energy was not included in the Lehman bankruptcy filing. On September 26, 2008, Eagle Energy notified us that EDF Trading Limited (EDFT), a wholly-owned subsidiary of Électricité de France SA (EDF), had entered into an agreement with Lehman to acquire Eagle Energy. The acquisition of Eagle Energy by EDFT was completed on October 31, 2008. We have received cash payment for all natural gas that has been sold to Eagle Energy and are continuing to do business with Eagle.

Chesapeake will continue to closely monitor the Lehman bankruptcy situation and will assert its rights under the various contractual relationships. We monitor the credit worthiness of all our counterparties and do not believe a failure by a counterparty would have a material negative impact on our liquidity.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Supplemental Disclosures About Natural Gas and Oil Producing Activities

Net Capitalized Costs

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

	December 31, 2008	December 31, 2007
	($ in millions)	
Natural gas and oil properties:		
Proved	$ 28,965	$ 27,656
Unproved	11,216	5,641
Total	40,181	33,297
Less accumulated depreciation, depletion and amortization	(11,866)	(7,112)
Net capitalized costs	$ 28,315	$ 26,185

Unproved properties not subject to amortization at December 31, 2008, 2007 and 2006 consisted mainly of leasehold acquired through corporate and significant natural gas and oil property acquisitions and through direct purchases of leasehold. We capitalized approximately $464 million, $269 million and $179 million of interest during 2008, 2007 and 2006, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. We will continue to evaluate our unevaluated properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

Costs Incurred in Natural Gas and Oil Exploration and Development, Acquisitions and Divestitures

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

		December 31,	
	2008	2007	2006
		($ in millions)	
Development and exploration costs:			
Development drilling (a)	$ 5,185	$ 4,402	$ 2,772
Exploratory drilling	612	653	349
Geological and geophysical costs (b)	314	343	154
Asset retirement obligation and other	10	29	23
Total	6,121	5,427	3,298
Acquisition costs:			
Proved properties	355	671	1,175
Unproved properties (c)	8,129	2,465	3,473
Deferred income taxes	13	131	180

Total	8,497	3,267	4,828
Proceeds from divestitures:			
Proved properties	(2,433)	(1,142)	
Unproved properties	(5,302)		
Total	$ 6,883	$ 7,552	$ 8,126

(a) Includes capitalized internal cost of $326 million, $243 million and $147 million, respectively.
(b) Includes capitalized internal cost of $26 million, $19 million and $13 million, respectively.
(c) Includes costs to acquire new leasehold and related capitalized interest.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Chesapeake s results of operations from natural gas and oil producing activities are presented below for 2008, 2007 and 2006. The following table includes revenues and expenses associated directly with our natural gas and oil producing activities. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our natural gas and oil operations.

	Years Ended December 31,		
	2008	2007	2006
		($ in millions)	
Natural gas and oil sales (a)	$ 7,858	$ 5,624	$ 5,619
Production expenses	(889)	(640)	(490)
Production taxes	(284)	(216)	(176)
Impairment of natural gas and oil properties	(2,800)		
Depletion and depreciation	(1,970)	(1,835)	(1,359)
Imputed income tax provision (b)	(747)	(1,115)	(1,383)
Results of operations from natural gas and oil producing activities	$ 1,168	$ 1,818	$ 2,211

(a) Includes $797 million, ($374) million and $495 million of unrealized gains (losses) on natural gas and oil derivatives for the years ended December 31, 2008, 2007 and 2006, respectively.

(b) The imputed income tax provision is hypothetical (at the effective income tax rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision will be payable.

Natural Gas and Oil Reserve Quantities (unaudited)

Chesapeake s petroleum engineers and internal staff estimated all of our proved reserves as of December 31, 2008, and independent petroleum engineering firms audited an aggregate of 76% of our estimated proved reserves (by volume), as set forth below. A reserve audit is not the same as a financial audit and a reserve audit is less rigorous in nature than a reserve report prepared by an independent petroleum engineering firm containing its own estimate of reserves.

	December 31, 2008
Netherland, Sewell & Associates, Inc.	42%
Lee Keeling and Associates, Inc.	13%
Data and Consulting Services, Division of Schlumberger Technology Corporation	8%
Ryder Scott Company L.P.	8%
LaRoche Petroleum Consultants, Ltd.	5%

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Independent petroleum engineers and Chesapeake s petroleum engineers estimated our proved reserves as of December 31, 2007 and 2006. The portion of proved reserves (by volume) estimated by each is presented below.

	December 31,	
	2007	2006
Netherland, Sewell & Associates, Inc.	34%	32%
Lee Keeling and Associates, Inc.	11	14
Data and Consulting Services, Division of Schlumberger Technology Corporation	12	16
Ryder Scott Company L.P.	11	10
LaRoche Petroleum Consultants, Ltd.	11	8
Internal petroleum engineers	21	20
	100%	100%

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

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

Proved developed natural gas and oil reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Additional natural gas and oil 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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Presented below is a summary of changes in estimated reserves of Chesapeake for 2008, 2007 and 2006:

	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
December 31, 2008			
Proved reserves, beginning of period	123,554	10,137,299	10,878,623
Extensions, discoveries and other additions	11,465	1,526,364	1,595,156
Revisions of previous estimates	(1,186)	956,908	949,792
Production	(11,220)	(775,424)	(842,744)
Sale of reserves-in-place	(4,563)	(674,177)	(701,552)
Purchase of reserves-in-place	2,582	156,485	171,974
Proved reserves, end of period	120,632	11,327,455	12,051,249
Proved developed reserves:			
Beginning of period	88,834	6,408,622	6,941,626
End of period	84,913	7,581,523	8,091,002
December 31, 2007			
Proved reserves, beginning of period	106,030	8,319,434	8,955,614
Extensions, discoveries and other additions	11,644	1,053,123	1,122,986
Revisions of previous estimates	7,732	1,298,802	1,345,195
Production	(9,882)	(654,969)	(714,261)
Sale of reserves-in-place		(208,141)	(208,141)
Purchase of reserves-in-place	8,030	329,050	377,230
Proved reserves, end of period	123,554	10,137,299	10,878,623
Proved developed reserves:			
Beginning of period	76,705	5,113,211	5,573,441
End of period	88,834	6,408,622	6,941,626
December 31, 2006			
Proved reserves, beginning of period	103,323	6,900,754	7,520,690
Extensions, discoveries and other additions	8,456	777,858	828,594
Revisions of previous estimates	(3,822)	539,606	516,676
Production	(8,654)	(526,459)	(578,383)
Sale of reserves-in-place	(3)	(123)	(141)
Purchase of reserves-in-place	6,730	627,798	668,178
Proved reserves, end of period	106,030	8,319,434	8,955,614
Proved developed reserves:			
Beginning of period	76,238	4,442,270	4,899,694

End of period	76,705	5,113,211	5,573,441

During 2008, Chesapeake acquired approximately 172 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $355 million (primarily in five separate transactions of greater than $10 million each) and we sold 702 bcfe of our proved reserves for approximately $2.433 billion. During 2008, we recorded positive revisions of 950 bcfe to the December 31, 2007 estimates of our reserves. Included in the revisions were 298 bcfe of negative adjustments caused by lower natural gas prices at December 31, 2008, and

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1.248 tcfe of positive performance related revisions. Lower prices decrease the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves. The weighted average natural gas and oil wellhead prices used in computing our reserves were $5.12 per mcf and $41.60 per bbl at December 31, 2008.

During 2007, Chesapeake acquired approximately 377 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $671 million (primarily in 10 separate transactions of greater than $10 million each). In December 2007, we sold 208 bcfe of our proved reserves in certain Chesapeake-operated producing assets in Kentucky and West Virginia for approximately $1.142 billion. During 2007, we recorded positive revisions of 1.345 tcfe to the December 31, 2006 estimates of our reserves. Included in the revisions were 97 bcfe of positive adjustments caused by higher natural gas prices at December 31, 2007, and 1.248 tcfe of positive performance related revisions of which 1.207 tcfe relate to infill drilling and increased density locations. Higher prices extend the economic lives of the underlying natural gas and oil properties and thereby increase the estimated future reserves. The weighted average natural gas and oil wellhead prices used in computing our reserves were $6.19 per mcf and $90.58 per bbl at December 31, 2007.

During 2006, Chesapeake acquired approximately 668 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $1.175 billion (primarily in 15 separate transactions of greater than $10 million each). During 2006, we recorded upward revisions of 517 bcfe to the December 31, 2005 estimates of our reserves. Included in the revisions were 212 bcfe of downward adjustments caused by lower natural gas prices at December 31, 2006, offset by 729 bcfe of positive performance related revisions of which 710 bcfe relate to infill drilling and increased density locations. Lower prices reduce the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves. The weighted average natural gas and oil wellhead prices used in computing our reserves were $5.41 per mcf and $56.25 per bbl at December 31, 2006.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

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

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

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Years Ended December 31,		
	2008	2007	2006
		($ in millions)	
Future cash inflows	$ 62,995(a)	$ 73,955(b)	$ 50,984(c)
Future production costs	(18,828)	(19,319)	(13,790)
Future development costs	(7,378)	(8,315)	(6,804)
Future income tax provisions	(9,813)	(14,056)	(8,877)
Future net cash flows	26,976	32,265	21,513
Less effect of a 10% discount factor	(15,143)	(17,303)	(11,506)
Standardized measure of discounted future net cash flows	$ 11,833	$ 14,962	$ 10,007

(a) Calculated using weighted average prices of $41.60 per barrel of oil and $5.12 per mcf of natural gas.
(b) Calculated using weighted average prices of $90.58 per barrel of oil and $6.19 per mcf of natural gas.
(c) Calculated using weighted average prices of $56.25 per barrel of oil and $5.41 per mcf of natural gas.

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

	Years Ended December 31,		
	2008	2007	2006
		($ in millions)	
Standardized measure, beginning of period (a)	$ 14,962	$ 10,007	$ 15,968
Sales of natural gas and oil produced, net of production costs (b)	(5,896)	(3,939)	(3,204)
Net changes in prices and production costs	(5,025)	3,277	(10,954)
Extensions and discoveries, net of production and development costs	2,752	2,424	1,184
Changes in future development costs	1,043	(639)	(743)
Development costs incurred during the period that reduced future development costs	1,130	1,410	954
Revisions of previous quantity estimates	1,524	2,960	948
Purchase of reserves-in-place	362	1,166	1,135
Sales of reserves-in-place	(1,696)	(708)	
Accretion of discount	2,057	1,365	2,293
Net change in income taxes	1,843	(1,970)	3,325
Changes in production rates and other	(1,223)	(391)	(899)
Standardized measure, end of period (a)	$ 11,833	$ 14,962	$ 10,007

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

(b) Excluding gains (losses) on derivatives.

11. Divestitures

Joint Ventures

In 2008, we entered into three joint ventures to sell a portion of our leasehold in the joint venture areas, which allowed us to recover much or all of our initial leasehold investments in the plays, reduce our ongoing capital costs and reduce future risks. The transactions are detailed below.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On July 1, 2008, we entered into a joint venture with Plains Exploration & Production Company to develop our Haynesville Shale leasehold in Northwest Louisiana and East Texas. Under the terms of the joint venture, Plains acquired a 20% interest in approximately 550,000 net acres of our Haynesville Shale leasehold for $1.65 billion in cash. Plains also agreed to fund 50% of our remaining 80% share of the costs associated with drilling and completing future Haynesville Shale joint venture wells over a multi-year period, up to an additional $1.65 billion. In addition, Plains has the right to a 20% participation in any additional leasehold we acquire in the Haynesville Shale at our cost plus a fee. Chesapeake and Plains amended the joint venture in February 2009 to provide Plains a one-time option in June 2010 to reduce its obligation to fund our drilling and completion costs by $800 million in exchange for assigning us 50% of its interest in the Haynesville joint venture properties. PXP s commitment to fund 50% of our share of future drilling and completion costs (up to $1.65 billion) is expected to reduce future DD&A expense by reducing the amount of capital we will invest to develop our Haynesville properties.

On September 5, 2008, we entered into a joint venture with BP America Inc. to develop our Fayetteville Shale leasehold in Arkansas. Under the terms of the joint venture, BP acquired a 25% interest in approximately 540,000 net acres of our Fayetteville Shale leasehold for $1.1 billion in cash. BP has also agreed to pay $800 million by funding 100% of Chesapeake s 75% share of drilling and completion expenditures until the $800 million obligation has been funded. In addition, BP has the right to a 25% participation in any additional leasehold we acquire in the Fayetteville Shale at our cost plus a fee. BP s commitment to fund our share of future drilling and completion costs (up to $800 million) is expected to reduce future DD&A expense by reducing the amount of capital we will invest to develop our Fayetteville properties.

On November 25, 2008, we entered into a joint venture with StatoilHydro ASA to develop our Marcellus Shale leasehold in Appalachia. Under the terms of the joint venture, StatoilHydro acquired a 32.5% interest in our Marcellus Shale assets for $3.375 billion. The assets included approximately 1.8 million net acres of leasehold, of which StatoilHydro now owns approximately 0.6 million net acres and Chesapeake owns approximately 1.2 million net acres. Chesapeake received $1.25 billion in cash from StatoilHydro funding 75% of Chesapeake s 67.5% share of drilling and completion expenditures until the $2.125 billion obligation has been funded. In addition, StatoilHydro has the right to a 32.5% participation in any additional leasehold we acquire in the Marcellus Shale. StatoilHydro s commitment to fund 75% of our share of future drilling and completion costs (up to $2.125 billion) is expected to reduce future DD&A expense by reducing the amount of capital we will invest to develop our Marcellus properties.

For accounting purposes, cash proceeds from these transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Volumetric Production Payments

On May 1, 2008, we sold certain long-lived producing assets in Texas, Oklahoma and Kansas in a volumetric production payment transaction for net proceeds of $616 million. These assets had estimated proved reserves of approximately 94 bcfe and current net production (at the time of sale) of approximately 47 mmcfe per day. Chesapeake retained drilling rights on the properties below currently producing intervals.

On August 1, 2008, we completed a volumetric production payment transaction with estimated proved reserves of approximately 93 bcfe and current net production (at the time of sale) of approximately 46 mmcfe per day from wells in the Anadarko Basin of Oklahoma. This transaction resulted in net proceeds to us of $594 million. Chesapeake retained drilling rights on the properties below currently producing intervals and retained all remaining production after approximately 11 years.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On December 31, 2008, we sold certain long-lived producing assets in the Anadarko and Arkoma Basins in a volumetric production payment transaction for net proceeds of $412 million. These assets had estimated proved reserves of approximately 98 bcfe and current net production (at the time of sale) of approximately 60 mmcfe per day. Chesapeake retained drilling rights on the properties below currently producing intervals.

On December 31, 2007, we sold a portion of our proved reserves and production in certain Chesapeake-operated producing assets in Kentucky and West Virginia in a volumetric production payment for net proceeds of approximately $1.1 billion. These assets had estimated proved reserves of approximately 208 bcfe and current net production (at the time of sale) of approximately 55 mmcfe per day. Chesapeake retained drilling rights on the properties below currently producing intervals.

For accounting purposes, cash proceeds from these transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized and our proved reserves were reduced accordingly.

Other Divestitures

On August 8, 2008, BP America Inc. acquired all of our interests in approximately 90,000 net acres of leasehold and producing natural gas properties in the Arkoma Basin Woodford Shale play for $1.7 billion in cash. The properties were producing approximately 50 mmcfe per day (at the time of sale).

Also in 2008, we sold non-core natural gas and oil assets in the Rocky Mountains and in the Mid-Continent for proceeds of approximately $400 million.

12. Investments

At December 31, 2008, investments accounted for under the equity method totaled $426 million and investments accounted for under the cost method totaled $18 million. Following is a summary of our investments:

			December 31, 2008	December 31, 2007
	Approximate % Owned	Accounting Method	Carrying Value	Carrying Value
			($ in millions)	
Frac Tech Services, Ltd (a)	20%	Equity	$ 223	$ 237
Chaparral Energy, Inc. (b) (c)	32%	Equity	152	271
DHS Drilling Company (b)	47%	Equity	19	28
Sierra Mid-Con, L.P.	50%	Equity	12	
Gastar Exploration Ltd (d)	17%	Cost	11	42
Mountain Drilling Company (b)	49%	Equity	9	19
Ventura Refining and Transmission LLC (e)	25%	Equity		
Other			18	15
			$ 444	$ 612

(a) The carrying value of our investment in Frac Tech is in excess of our underlying equity in net assets by approximately $160 million as of December 31, 2008. This excess amount is attributed to certain intangibles associated with the specialty services provided by Frac Tech and is being amortized over the estimated life of the intangibles.

(b) Our investees have been impacted by the dramatic slowing of the worldwide economy and the freezing of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness has resulted in

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

significantly reduced oil and natural gas prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized that an other than temporary impairment had occurred on the following investments: Chaparral Energy of $100 million, DHS Drilling Company of $20 million and Mountain Drilling Company of $10 million. We will continue to monitor the performance of our investments, and it is reasonably possible that we may experience additional impairments, although we do not believe that our exposure to future charges would be material to our consolidated results of operations.

(c) The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $107 million as of December 31, 2008. This excess is attributed to the natural gas and oil reserves held by Chaparral and is being amortized over the estimated life of these reserves based on a unit of production rate.

(d) Our investment in Gastar had an associated cost basis of $89 million as of December 31, 2008 and 2007.

(e) In early 2007, we invested approximately $1 million in Ventura Refining and Transmission LLC to acquire a 25% interest and subsequently entered into certain lending agreements with Ventura for which approximately $54 million was outstanding at December 31, 2008. Due to worsening economic conditions, the lack of third party credit available to Ventura, and poor operating performance in the second half of 2008, management determined that an impairment had occurred and recognized a charge of $50 million at December 31, 2008. See Note 4 for further information regarding our guarantee of Ventura s performance.

In 2007, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $124 million and a gain of $83 million.

In 2006, we sold our investment in publicly-traded Pioneer Drilling Company common stock, realizing proceeds of $159 million and a gain of $117 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

The table below presents summarized financial information for our significant equity method investments, including Chaparral, Frac Tech, Ventura, Mountain Drilling and DHS. The investee financial information reflects the most current financial information available to investors and includes lags in financial reporting of up to one quarter.

	December 31,	
	2008	2007
	($ in millions)	
Current assets	$ 411	$ 274
Noncurrent assets	$ 2,490	$ 2,185
Current liabilities	$ 429	$ 312
Noncurrent liabilities	$ 1,883	$ 1,673
Gross revenue	$ 1,523	$ 972
Operating Expense	$ 1,261	$ 739
Net Income	$ 105	$ 67

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Fair Value Measurements

Effective January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157, Fair Value Measurements for our financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities.

SFAS 157 defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses appropriate valuation techniques based on available inputs, including counterparty quotes, to measure the fair values of its assets and liabilities. Counterparty quotes are generally assessed as a Level 3 input.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2008.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Cash equivalents	$ 1,749	$	$	$ 1,749
Derivatives, net	$	$ 874	$ 292	$ 1,166
Investments	$ 11	$	$	$ 11
Other long-term assets	$ 19	$	$	$ 19
Long-term debt	$	$	$ (1,470)	$ (1,470)
Other long-term liabilities	$ (19)	$	$	$ (19)

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 1 Fair Value Measurements

Cash Equivalents. The fair value of cash equivalents is based on quoted market prices.

Investments. The fair value of Chesapeake s investment in Gastar Exploration Ltd. common stock is based on a quoted market price.

Other Long-Term Assets and Liabilities. The fair value of other long-term assets and liabilities, consisting of obligations under our Deferred Compensation Plan, is based on quoted market prices.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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Level 2 Fair Value Measurements

Derivatives. The fair values of our natural gas swaps are measured internally using established index prices and other sources. These values are based upon, among other things, futures prices and time to maturity.

Level 3 Fair Value Measurements

Derivatives. The fair value of our derivative instruments, excluding natural gas swaps, have been established utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives.

Debt. The fair value of our long-term debt is based on face value of the debt along with the value of the related interest rate swaps. The interest rate swap values are based on estimates provided by our respective counterparties and reviewed internally for reasonableness using future interest rate curves and time to maturity.

A reconciliation of Chesapeake s assets and liabilities classified as Level 3 measurements is presented below.

	Derivatives	Debt ($ in millions)	Total
Balance of Level 3 as of January 1, 2008	$ (340)	$ (2,404)	$ (2,744)
Total gains or losses (realized/unrealized):			
Included in earnings (a)	744	184	928
Included in other comprehensive income (loss)	(82)		(82)
Purchases, issuances and settlements	(30)	750(b)	720
Transfers in and out of Level 3			
Balance of Level 3 as of December 31, 2008	$ 292	$ (1,470)	$ (1,178)

		Natural Gas and Oil Revenue	Interest
		($ in millions)	
(a)	Total gains and losses related to derivatives included in earnings for the period	$ 876	$ (132)
	Change in unrealized gains or losses relating to assets still held at reporting date	$ 815	$ (126)

(b) Amount represents debt no longer recorded at fair value as a result of the termination of interest rate swaps in 2008.

14. Asset Retirement Obligations

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

	Years Ended December 31, 2008	2007
	($ in millions)	
Asset retirement obligations, beginning of period	$ 236	$ 193
Additions	21	19
Revisions (a)		10
Settlements and disposals	(5)	(1)
Accretion expense	17	15
Asset retirement obligations, end of period	$ 269	$ 236

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(a) Based on increasing service costs, we revised our asset retirement obligation related to natural gas and oil wells in 2007.

15. Major Customers and Segment Information

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

Year Ended December 31,	Customer	Amount ($ in millions)	Percent of Total Revenues
2008	Eagle Energy Partners I, L.P.	$ 1,283	12%
2007	Eagle Energy Partners I, L.P.	$ 1,072	15%
2006	Eagle Energy Partners I, L.P.	$ 867	16%

In September 2003, Chesapeake invested in Eagle Energy Partners I, L.P. and received a 25% limited partnership interest. Through additional investments, Chesapeake increased its limited partner ownership interest to approximately 33% as of December 31, 2006. In 2007, we sold our 33% limited partnership interest for proceeds of $124 million and a gain of $83 million.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Management evaluates the performance of our segments based upon income before income taxes. Revenues from the marketing segment s sale of natural gas and oil related to Chesapeake s ownership interests are reflected as exploration and production revenues. Such amounts totaled $5.5 billion, $3.5 billion and $2.6 billion for 2008, 2007 and 2006, respectively. The following tables present selected financial information for Chesapeake s operating segments. Our drilling and trucking service operations are presented in Other Operations for all periods presented.

	Exploration and Production	Marketing	Other Operations ($ in millions)	Intercompany Eliminations	Consolidated Total
For the Year Ended December 31, 2008:					
Revenues	$ 7,858	$ 9,126	$ 631	$ (5,986)	$ 11,629
Intersegment revenues		(5,528)	(458)	5,986	
Total Revenues	7,858	3,598	173		11,629
Depreciation, depletion and amortization	2,111	28	35	(27)	2,147
Interest and other income	3	6	(14)	(6)	(11)
Interest expense	314	2		(2)	314
Impairment of natural gas and oil properties and other fixed assets	(2,800)	(30)			(2,830)
Impairment of investments	(180)				(180)
Gain on exchanges or repurchases of debt	237				237
INCOME BEFORE INCOME TAXES	$ 1,177	$ 28	$ 68	$ (87)	$ 1,186
TOTAL ASSETS	$ 35,043	$ 3,416	$ 688	$ (703)	$ 38,444
CAPITAL EXPENDITURES	$ 7,658	$ 1,765	$ 229	$	$ 9,652
For the Year Ended December 31, 2007:					
Revenues	$ 5,624	$ 5,508	$ 493	$ (3,825)	$ 7,800
Intersegment revenues		(3,468)	(357)	3,825	
Total Revenues	5,624	2,040	136		7,800
Depreciation, depletion and amortization	1,954	25	26	(16)	1,989
Interest and other income	14	1			15
Interest expense	406				406
Other income/expense	83				83
INCOME BEFORE INCOME TAXES	$ 2,287	$ 41	$ 135	$ (122)	$ 2,341
TOTAL ASSETS	$ 29,317	$ 1,759	$ 487	$ (829)	$ 30,734
CAPITAL EXPENDITURES	$ 7,977	$ 534	$ (163)	$	$ 8,348
For the Year Ended December 31, 2006:					
Revenues	$ 5,619	$ 4,135	$ 325	$ (2,753)	$ 7,326
Intersegment revenues		(2,558)	(195)	2,753	
Total Revenues	5,619	1,577	130		7,326
Depreciation, depletion and amortization	1441	10	28	(16)	1,463
Interest and other income	22	4			26
Interest expense	300		1		301
Other income/expense	117				117
INCOME BEFORE INCOME TAXES	$ 3,192	$ 41	$ 106	$ (84)	$ 3,255

TOTAL ASSETS	$	23,333	$	864	$	786	$	(566)	$	24,417
CAPITAL EXPENDITURES	$	8,423	$	255	$	231	$		$	8,909

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. As of December 31, 2007, our obligations under our outstanding senior notes and contingent convertible notes listed in Note 3 were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis. Since October 2008, following the restructuring of our non-Appalachian midstream operations, as described in Note 3, certain of our wholly-owned subsidiaries having significant assets and operations have not guaranteed our outstanding notes. The midstream revolving credit facility referred to in Note 3 contains a covenant restricting Chesapeake Midstream Partners, L.P., the parent of our midstream subsidiaries, from paying dividends or distributions or making loans to Chesapeake.

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (the parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of and for the year ended December 31, 2008. We have not provided comparative financial statements because the non-guarantor subsidiaries as of December 31, 2007 were minor subsidiaries individually and in the aggregate. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF DECEMBER 31, 2008

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 1,749	$	$	$ 1,749
Other current assets	13	2,372	189	(31)	2,543
Total Current Assets	13	4,121	189	(31)	4,292
PROPERTY AND EQUIPMENT:					
Total natural gas and oil properties, at cost based on full-cost accounting, net		28,300	15		28,315
Other property and equipment, net		1,918	2,912		4,830
Total Property and Equipment		30,218	2,927		33,145
Other assets	155	837	15		1,007
Investments in subsidiaries and intercompany advance	8,455	140		(8,595)	
TOTAL ASSETS	$ 8,623	$ 35,316	$ 3,131	$ (8,626)	$ 38,444
CURRENT LIABILITIES:					
Current liabilities	$ 257	$ 3,322	$ 133	$ (91)	$ 3,621
Intercompany payable (receivable) from parent	(18,172)	15,947	2,165	60	
Total Current Liabilities	(17,915)	19,269	2,298	(31)	3,621
Long-term debt, net	10,250	3,474	460		14,184
Deferred income tax liability	65	3,471	227		3,763
Other liabilities	(74)	647	6		579
Total Long-Term Liabilities	10,241	7,592	693		18,526
Total Stockholders Equity	16,297	8,455	140	(8,595)	16,297
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 8,623	$ 35,316	$ 3,131	$ (8,626)	$ 38,444

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the Year Ended December 31, 2008:					
REVENUES:					
Natural gas and oil sales	$	$ 7,856	$ 2	$	$ 7,858
Natural gas and oil marketing sales		3,420	333	(155)	3,598
Service operations revenue		170	47	(44)	173
Total Revenues		11,446	382	(199)	11,629
OPERATING COSTS:					
Production expenses		889			889
Production taxes		284			284
General and administrative expenses		354	23		377
Natural gas and oil marketing expenses		3,363	142		3,505
Service operations expense		142	21	(20)	143
Impairment of natural gas and oil properties and other fixed assets		2,800	30		2,830
Natural gas and oil depreciation, depletion and amortization		1,970			1,970
Depreciation and amortization of other assets	17	126	65	(31)	177
Total Operating Costs	17	9,928	281	(51)	10,175
INCOME FROM OPERATIONS	(17)	1,518	101	(148)	1,454
OTHER INCOME (EXPENSE):					
Interest and other income (expense)	558	(20)	9	(558)	(11)
Interest expense	(551)	(313)	(8)	558	(314)
Impairment of investments		(130)	(50)		(180)
Gain on exchanges or repurchases of Chesapeake debt	237				237
Equity in net earnings of subsidiary	585	(58)		(527)	
Total Other Income (Expense)	829	(521)	(49)	(527)	(268)
INCOME BEFORE INCOME TAXES	812	997	52	(675)	1,186
INCOME TAX EXPENSE	89	412	20	(58)	463
NET INCOME	$ 723	$ 585	$ 32	$ (617)	$ 723

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the Year Ended December 31, 2008:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 156	$ 5,493	$ 204	$ (617)	$ 5,236
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(14,567)	(9)		(14,576)
Divestitures of proved and unproved natural gas and oil properties		7,652	18		7,670
Additions to other property and equipment		(1,284)	(1,789)		(3,073)
Other investing activities		163	(28)		135
Cash used in investing activities		(8,036)	(1,808)		(9,844)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facility borrowings		12,831	460		13,291
Payments on credit facility borrowings		(11,307)			(11,307)
Proceeds from issuance of senior notes, net of offering costs	2,136				2,136
Proceeds from issuance of common stock, net of offering costs	2,598				2,598
Other financing activities	(514)	162	(10)		(362)
Intercompany advances, net	(4,376)	2,605	1,154	617	
Cash provided by financing activities	(156)	4,291	1,604	617	6,356
Net increase (decrease) in cash and cash equivalents		1,748			1,748
Cash and cash equivalents, beginning of period		1			1
Cash and cash equivalents, end of period	$	$ 1,749	$	$	$ 1,749

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2008 and 2007 are as follows ($ in millions except per share data):

	Quarters Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008 (b)
Total revenues	$ 1,611	$ (455)	$ 7,491	$ 2,982
Gross profit (loss) (a)	(104)	(2,533)	5,478	(1,387)
Net income (loss)	(132)	(1,597)	3,313	(861)
Net income (loss) available to common shareholders	(143)	(1,649)	3,282	(867)
Net earnings (loss)per common share:				
Basic	$ (0.29)	$ (3.17)	$ 5.93	$ (1.51)
Diluted	$ (0.29)	$ (3.17)	$ 5.61	$ (1.51)

	Quarters Ended			
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
Total revenues	$ 1,580	$ 2,105	$ 2,027	$ 2,088
Gross profit (a)	486	836	715	612
Net income	258	518(c)	372	303
Net income available to common shareholders	232	493(c)	346	158
Net earnings per common share:				
Basic	$ 0.51	$ 1.09	$ 0.76	$ 0.34
Diluted	$ 0.50	$ 1.01	$ 0.72	$ 0.33

(a) Total revenue less operating costs.

(b) Includes a non-cash pre-tax impairment charge of $3.010 billion related to the carrying value of natural gas and oil properties and certain investments and a pre-tax gain of $268 million on exchanges of certain of our contingent convertible senior notes.

(c) Includes a pre-tax gain on sale of investment of $83 million.

18. Recently Issued Accounting Standards

The FASB recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51.* This statement requires an entity to separately disclose non-controlling interests as a separate component of equity in the balance sheet and clearly identify on the face of the income statement net income related to non-controlling interests. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. The adoption of this statement will not have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (R), *Business Combinations.* This statement requires assets acquired and liabilities assumed to be measured at fair value as of the acquisition date, acquisition-related costs incurred prior to the acquisition to be expensed and contractual contingencies to be recognized at fair value as of the acquisition date. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We will comply with this statement prospectively in accounting for future business combinations.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133.* This statement changes the disclosure requirements for derivative instruments and hedging activities. The statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. This statement will not have a material impact on our financial disclosures.

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement).* FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon either mandatory or optional conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants.* The accounting prescribed by FSP APB 14-1 increases the amount of interest expense required to be recognized with respect to such instruments and, thus, lowers reported net income and net income per share of issuers of such instruments. Issuers must account for the liability and equity components of the instrument separately and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. We have three debt series that will be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038. This staff position is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008 and must be applied on a retrospective basis. The initial adoption of FSP APB 14-1 is expected to decrease the carrying value of our Contingent Convertible Senior Notes by approximately $1 billion, increase shareholders equity by approximately $600 million and increase deferred tax liabilities by approximately $400 million. In addition, we currently estimate that we will record additional non-cash interest expense, which will reduce our pre-tax income by approximately $80 million and reduce net income by approximately $50 million for the year ended December 31, 2009.

In June 2008, the FASB issued FSP Emerging Issues Task Force (EITF) No. 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.* FSP EITF 03-6-1 addresses whether instruments granted in share-based payments transactions are participating securities prior to vesting and therefore need to be included in the earnings allocation in calculating earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share.* FSP EITF No. 03-6-1 requires companies to treat unvested share-based payment awards that have non-forfeitable rights to dividend or dividend equivalents as a separate class of securities in calculating earnings per share. FSP EITF No. 03-6-1 is effective for fiscal years beginning after December 15, 2008; earlier application is not permitted. FSP EITF No. 03-6-1 could be applicable to us but we have no current transactions that would be affected.

In October 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active.* FSP FAS 157-3 clarifies the application of FASB statement No. 157, *Fair Value Measurements,* in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP could be applicable to us but we currently have no financial assets of this type.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualifications of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

reserves estimates. The new rules also require that oil and gas reserves be reported and the full-cost ceiling value calculated using an average price based upon the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are in the process of assessing the impact of these new requirements on our financial position, results of operations and financial disclosures.

19. Subsequent Events

On February 2, 2009, we completed a public offering of $1 billion aggregate principal amount of senior notes due 2015, which have an interest rate of 9.5% per annum. The senior notes were priced at 95.071% of par to yield 10.625%. On February 17, 2009, we completed an offering of an additional $425 million aggregate principal amount of the 9.5% Senior Notes due 2015. The additional senior notes were priced at 97.75% of par plus accrued interest from February 2 to February 17, 2009 to yield 10.0% per annum. Net proceeds of $1.343 billion from these two offerings were used to repay outstanding indebtedness under our revolving bank credit facility, which we anticipate reborrowing from time to time to fund drilling and leasehold acquisition initiatives and for general corporate purposes.

On February 20, 2009, we amended our Haynesville Shale joint venture agreement with Plains Exploration & Production Company to provide Plains a one-time option in June 2010 to reduce its maximum drilling cost carry obligation by $800 million in exchange for assigning us, effective December 31, 2010, 50% of its interest in the Haynesville joint venture properties. Chesapeake believes Plains cost basis in the properties that would be assigned to us upon exercise of the option could approximate $1.5 billion to $1.6 billion by December 31, 2010. If Plains exercises this option and has funded more than $850 million of its drilling cost carry as of December 31, 2010, we will be required to pay to Plains an amount equal to such excess. We will not be required to refund to Plains any of the $1.65 billion in cash consideration paid in July 2008 or any portion of the first $850 million in drilling cost carries to be paid by Plains.

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Schedule II

CHESAPEAKE ENERGY CORPORATION

VALUATION AND QUALIFYING ACCOUNTS

($ in millions)

Description	Balance at Beginning of Period	Additions: Charged To Expense	Additions: Charged To Other Accounts	Deductions	Balance at End of Period
December 31, 2008:					
Allowance for doubtful accounts	$ 8	$ 4	$	$	$ 12
Valuation allowance for deferred tax assets	$	$	$	$	$
December 31, 2007:					
Allowance for doubtful accounts	$ 6	$ 2	$	$	$ 8
Valuation allowance for deferred tax assets	$	$	$	$	$
December 31, 2006:					
Allowance for doubtful accounts	$ 5	$ 1	$	$	$ 6
Valuation allowance for deferred tax assets	$	$	$	$	$

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

Not applicable.

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

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of December 31, 2008, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake s disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of December 31, 2008, to ensure that information required to be disclosed by Chesapeake is accumulated and communicated to Chesapeake management, including Chesapeake s Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls

No changes in the company s internal control over financial reporting occurred during the quarter ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, the company s internal control over financial reporting.

Management s Report on Internal Control Over Financial Reporting

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

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

Not applicable.

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PART III

ITEM 10. ***Directors, Executive Officers and Corporate Governance***

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2009.

ITEM 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2009.

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

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2009.

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

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2009.

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

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2009.

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PART IV

ITEM 15. *Exhibits and Financial Statement Schedules*

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

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

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

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

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/09/2006	
3.1.2	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.3	08/11/2008	
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B).	10-Q	001-13726	3.1.4	11/10/2008	
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended.	S-8	333-151762	4.1.6	06/18/2008	
3.1.5	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008	
3.1.6	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock, as amended.	10-K	001-13726	3.1.7	02/29/2008	
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008	
4.1*	Indenture dated as of May 27, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.5% senior notes due 2014.	S-4	333-116555	4.1	06/17/2004	
4.2*	Indenture dated as of August 2, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.0% senior notes due 2014.	S-4	333-118378	4.1	08/20/2004	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.4*	Seventh Amended and Restated Credit Agreement, dated as of November 2, 2007, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland, as Syndication Agent, and Bank of America, N.A., SunTrust Bank and BNP Paribas, as Co-Documentation Agents, and the several lenders from time to time parties thereto.	8-K	001-13726	4.1	11/08/2007	
4.4.1*	Consent & Waiver Letter dated December 12, 2007 with respect to the Seventh Amended and Restated Credit Agreement, dated as of November 2, 2007, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland, as Syndication Agent, and Bank of America, N.A., SunTrust Bank and BNP Paribas, as Co-Documentation Agents, and the several lenders from time to time parties thereto.	10-K	001-13726	4.4.1	02/29/2008	
4.5*	Indenture dated as of March 5, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.5% Senior Notes due 2013.	S-4	333-104396	4.7	04/09/2003	
4.6*	Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2016.	S-4/A	333-110668	4.2	12/01/2003	
4.7*	Indenture dated as of December 8, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A. Trust Company, N.A., as Trustee, with respect to 6.375% senior notes due 2015.	8-K	001-13726	4.1	12/14/2004	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.8*	Indenture dated as of April 19, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.625% senior notes due 2016.	10-Q	001-13726	4.12	05/10/2005	
4.9*	Indenture dated as of June 20, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.25% senior notes due 2018.	10-Q	001-13726	4.1	08/08/2005	
4.10*	Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.50% senior notes due 2017.	8-K	001-13726	4.1	08/16/2005	
4.11*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2020.	8-K	001-13726	4.1.1	11/15/2005	
4.12*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.75% contingent convertible senior notes due 2035.	8-K	001-13726	4.1.2	11/15/2005	
4.13*	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.625% senior notes due 2013.	8-K	001-13726	4.1	06/30/2006	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.14*	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% senior notes due 2017.	8-K	001-13726	4.1	12/06/2006	
4.15*	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.50% contingent convertible senior notes due 2037.	8-K	001-13726	4.1	05/15/2007	
4.16*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.25% senior notes due 2018.	8-K	001-13726	4.1	05/29/2008	
4.17*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.25% contingent convertible senior notes due 2038.	8-K	001-13726	4.2	05/29/2008	
4.18*	Indenture dated as of February 2, 2009 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 9.50% contingent convertible senior notes due 2015.	8-K	001-13726	4.1	02/03/2009	
4.18.1*	First Supplemental Indenture dated as of February 10, 2009 to Indenture dated as of February 2, 2009 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to the 9.50% senior notes due 2015.	8-K	001-13726	4.2	02/17/2009	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.1.1	Chesapeake s 2003 Stock Incentive Plan, as amended.	10-Q	001-13726	10.1.1	11/09/2007	
10.1.1.1	Form of Restricted Stock Award Agreement for the 2003 Stock Option Plan.					X
10.1.2	Chesapeake s 1992 Nonstatutory Stock Option Plan, as amended.	10-Q	001-13726	10.1.2	02/14/1997	
10.1.3	Chesapeake s 1994 Stock Option Plan, as amended.	10-Q	001-13726	10.1.3	11/07/2006	
10.1.4	Chesapeake s 1996 Stock Option Plan, as amended.	10-Q	001-13726	10.1.4	11/07/2006	
10.1.5	Chesapeake s 1999 Stock Option Plan, as amended.	10-Q	001-13726	10.1.5	08/11/2008	
10.1.6	Chesapeake s 2000 Employee Stock Option Plan, as amended.	10-Q	001-13726	10.1.6	08/11/2008	
10.1.7	Chesapeake s 2001 Stock Option Plan, as amended.	10-Q	001-13726	10.1.8	08/11/2008	
10.1.8	Chesapeake s 2001 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.10	08/11/2008	
10.1.9	Chesapeake s 2002 Stock Option Plan, as amended.	10-Q	001-13726	10.1.11	08/11/2008	
10.1.10	Chesapeake s 2002 Non-Employee Director Stock Option Plan.	10-Q	001-13726	10.1.12	08/11/2008	
10.1.11	Chesapeake s 2002 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.13	08/11/2008	
10.1.12	Chesapeake s 2003 Stock Award Plan for Non-Employee Directors, as amended.	10-K	001-13726	10.1.14	02/29/2008	
10.1.13	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan.	10-K	001-13726	10.1.16	02/29/2008	
10.1.14	Chesapeake s Amended and Restated Long Term Incentive Plan.	S-8	333-151762	99.1	06/18/2008	
10.1.14.1	Form of Restricted Stock Award Agreement for the Long Term Incentive Plan.	8-K	001-13726	10.1.18.2	06/16/2005	
10.1.14.2	Form of Non-Employee Director Restricted Stock Award Agreement for the Long Term Incentive Plan.	8-K	001-13726	10.1.18.3	06/16/2005	
10.1.15	Founder Well Participation Program.	DEF 14A	001-13726	B	04/29/2005	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.2.1	Employment Agreement dated as of December 31, 2008, between Aubrey K. McClendon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.1	01/07/2009	
10.2.2	Employment Agreement dated as of October 1, 2006 between Marcus C. Rowland and Chesapeake Energy Corporation.	8-K	001-13726	10.2.2	10/06/2006	
10.2.3	Employment Agreement dated as of October 1, 2006 between Steven C. Dixon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.3	10/06/2006	
10.2.4	Employment Agreement dated as of October 1, 2006 between J. Mark Lester and Chesapeake Energy Corporation.	8-K	001-13726	10.2.4	10/06/2006	
10.2.5	Employment Agreement dated as of January 1, 2007 between Douglas J. Jacobson and Chesapeake Energy Corporation.	10-K	001-13726	10.2.5	03/01/2007	
10.2.6	Employment Agreement dated as of January 1, 2007 between Martha A. Burger and Chesapeake Energy Corporation.	10-K	001-13726	10.2.2	12/20/06	
10.2.7	Form of Employment Agreement between Senior Vice President and Chesapeake Energy Corporation.	10-K	001-13726	10.2.6	02/29/2008	
10.3	Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries.	10-K	001-13726	10.3	02/29/2008	
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X
21	Subsidiaries of Chesapeake					X
23.1	Consent of PricewaterhouseCoopers, LLP					X
23.2	Consent of Netherland, Sewell & Associates, Inc.					X
23.3	Consent of Data & Consulting Services, Division of Schlumberger Technology Corporation					X
23.4	Consent of Lee Keeling and Associates, Inc.					X
23.5	Consent of Ryder Scott Company L.P.					X
23.6	Consent of LaRoche Petroleum Consultants, Ltd.					X
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X

* Chesapeake agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities and Exchange Commission upon request.

Management contract or compensatory plan or arrangement.

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SIGNATURES

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

CHESAPEAKE ENERGY CORPORATION

By /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon

Chairman of the Board and

Chief Executive Officer

Date: March 2, 2009

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Aubrey K. McClendon and Marcus C. Rowland, and each of them, either one of whom may act without joinder of the other, his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, and each of them, or the substitute or substitutes of any or all of them, may lawfully do or cause to be done by virtue hereof.

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

Signature	Capacity	Date
/s/ AUBREY K. MCCLENDON **Aubrey K. McClendon**	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	March 2, 2009
/s/ MARCUS C. ROWLAND **Marcus C. Rowland**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 2, 2009
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 2, 2009
/s/ RICHARD K. DAVIDSON **Richard K. Davidson**	Director	March 2, 2009
/s/ V. BURNS HARGIS **V. Burns Hargis**	Director	March 2, 2009

/s/ Frank Keating	Director	March 2, 2009
Frank Keating		

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Signature	Capacity	Date
/s/ Breene M. Kerr	Director	March 2, 2009
Breene M. Kerr		
/s/ Charles T. Maxwell	Director	March 2, 2009
Charles T. Maxwell		
/s/ Merrill A. Miller, Jr	Director	March 2, 2009
Merrill A. Miller, Jr.		
/s/ Don Nickles	Director	March 2, 2009
Don Nickles		
/s/ Frederick B. Whittemore	Director	March 2, 2009
Frederick B. Whittemore		

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EXHIBIT INDEX

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/09/2006	
3.1.2	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.3	08/11/2008	
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B).	10-Q	001-13726	3.1.4	11/10/2008	
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended.	S-8	333-151762	4.1.6	06/18/2008	
3.1.5	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008	
3.1.6	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock, as amended.	10-K	001-13726	3.1.7	02/29/2008	
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008	
4.1*	Indenture dated as of May 27, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.5% senior notes due 2014.	S-4	333-116555	4.1	06/17/2004	
4.2*	Indenture dated as of August 2, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.0% senior notes due 2014.	S-4	333-118378	4.1	08/20/2004	
4.4*	Seventh Amended and Restated Credit Agreement, dated as of November 2, 2007, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland, as Syndication Agent, and Bank of America, N.A., SunTrust Bank and BNP Paribas, as Co-Documentation Agents, and the several lenders from time to time parties thereto.	8-K	001-13726	4.1	11/08/2007	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.4.1*	Consent & Waiver Letter dated December 12, 2007 with respect to the Seventh Amended and Restated Credit Agreement, dated as of November 2, 2007, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland, as Syndication Agent, and Bank of America, N.A., SunTrust Bank and BNP Paribas, as Co-Documentation Agents, and the several lenders from time to time parties thereto.	10-K	001-13726	4.4.1	02/29/2008	
4.5*	Indenture dated as of March 5, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.5% Senior Notes due 2013.	S-4	333-104396	4.7	04/09/2003	
4.6*	Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2016.	S-4/A	333-110668	4.2	12/01/2003	
4.7*	Indenture dated as of December 8, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A. Trust Company, N.A., as Trustee, with respect to 6.375% senior notes due 2015.	8-K	001-13726	4.1	12/14/2004	
4.8*	Indenture dated as of April 19, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.625% senior notes due 2016.	10-Q	001-13726	4.12	05/10/2005	
4.9*	Indenture dated as of June 20, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.25% senior notes due 2018.	10-Q	001-13726	4.1	08/08/2005	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.10*	Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.50% senior notes due 2017.	8-K	001-13726	4.1	08/16/2005	
4.11*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2020.	8-K	001-13726	4.1.1	11/15/2005	
4.12*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.75% contingent convertible senior notes due 2035.	8-K	001-13726	4.1.2	11/15/2005	
4.13*	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.625% senior notes due 2013.	8-K	001-13726	4.1	06/30/2006	
4.14*	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% senior notes due 2017.	8-K	001-13726	4.1	12/06/2006	
4.15*	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.50% contingent convertible senior notes due 2037.	8-K	001-13726	4.1	05/15/2007	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.16*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.25% senior notes due 2018.	8-K	001-13726	4.1	05/29/2008	
4.17*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.25% contingent convertible senior notes due 2038.	8-K	001-13726	4.2	05/29/2008	
4.18*	Indenture dated as of February 2, 2009 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 9.50% contingent convertible senior notes due 2015.	8-K	001-13726	4.1	02/03/2009	
4.18.1*	First Supplemental Indenture dated as of February 10, 2009 to Indenture dated as of February 2, 2009 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to the 9.50% senior notes due 2015.	8-K	001-13726	4.2	02/17/2009	
10.1.1	Chesapeake s 2003 Stock Incentive Plan, as amended.	10-Q	001-13726	10.1.1	11/09/2007	
10.1.1.1	Form of Restricted Stock Award Agreement for the 2003 Stock Option Plan.					
10.1.2	Chesapeake s 1992 Nonstatutory Stock Option Plan, as amended.	10-Q	001-13726	10.1.2	02/14/1997	
10.1.3	Chesapeake s 1994 Stock Option Plan, as amended.	10-Q	001-13726	10.1.3	11/07/2006	
10.1.4	Chesapeake s 1996 Stock Option Plan, as amended.	10-Q	001-13726	10.1.4	11/07/2006	
10.1.5	Chesapeake s 1999 Stock Option Plan, as amended.	10-Q	001-13726	10.1.5	08/11/2008	
10.1.6	Chesapeake s 2000 Employee Stock Option Plan, as amended.	10-Q	001-13726	10.1.6	08/11/2008	
10.1.7	Chesapeake s 2001 Stock Option Plan, as amended.	10-Q	001-13726	10.1.8	08/11/2008	
10.1.8	Chesapeake s 2001 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.10	08/11/2008	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.1.9	Chesapeake s 2002 Stock Option Plan, as amended.	10-Q	001-13726	10.1.11	08/11/2008	
10.1.10	Chesapeake s 2002 Non-Employee Director Stock Option Plan.	10-Q	001-13726	10.1.12	08/11/2008	
10.1.11	Chesapeake s 2002 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.13	08/11/2008	
10.1.12	Chesapeake s 2003 Stock Award Plan for Non-Employee Directors, as amended.	10-K	001-13726	10.1.14	02/29/2008	
10.1.13	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan.	10-K	001-13726	10.1.16	02/29/2008	
10.1.14	Chesapeake s Amended and Restated Long Term Incentive Plan.	S-8	333-151762	99.1	06/18/2008	
10.1.14.1	Form of Restricted Stock Award Agreement for the Long Term Incentive Plan.	8-K	001-13726	10.1.18.2	06/16/2005	
10.1.14.2	Form of Non-Employee Director Restricted Stock Award Agreement for the Long Term Incentive Plan.	8-K	001-13726	10.1.18.3	06/16/2005	
10.1.15	Founder Well Participation Program.	DEF 14A	001-13726	B	04/29/2005	
10.2.1	Employment Agreement dated as of December 31, 2008, between Aubrey K. McClendon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.1	01/07/2009	
10.2.2	Employment Agreement dated as of October 1, 2006 between Marcus C. Rowland and Chesapeake Energy Corporation.	8-K	001-13726	10.2.2	10/06/2006	
10.2.3	Employment Agreement dated as of October 1, 2006 between Steven C. Dixon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.3	10/06/2006	
10.2.4	Employment Agreement dated as of October 1, 2006 between J. Mark Lester and Chesapeake Energy Corporation.	8-K	001-13726	10.2.4	10/06/2006	
10.2.5	Employment Agreement dated as of January 1, 2007 between Douglas J. Jacobson and Chesapeake Energy Corporation.	10-K	001-13726	10.2.5	03/01/2007	
10.2.6	Employment Agreement dated as of January 1, 2007 between Martha A. Burger and Chesapeake Energy Corporation.	10-K	001-13726	10.2.2	12/20/06	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.2.7	Form of Employment Agreement between Senior Vice President and Chesapeake Energy Corporation.	10-K	001-13726	10.2.6	02/29/2008	
10.3	Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries.	10-K	001-13726	10.3	02/29/2008	
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X
21	Subsidiaries of Chesapeake					X
23.1	Consent of PricewaterhouseCoopers, LLP					X
23.2	Consent of Netherland, Sewell & Associates, Inc.					X
23.3	Consent of Data & Consulting Services, Division of Schlumberger Technology Corporation					X
23.4	Consent of Lee Keeling and Associates, Inc.					X
23.5	Consent of Ryder Scott Company L.P.					