CHESAPEAKE ENERGY CORP
Form 10-K
March 01, 2011
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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, 2010

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

For the transition period from ______ to ______

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact name of registrant as specified in its charter)

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

(405) 848-8000

(Registrant s telephone number, including area code)

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

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, par value $0.01	New York Stock Exchange
7.625% Senior Notes due 2013	New York Stock Exchange
9.5% Senior Notes due 2015	New York Stock Exchange
6.25% Senior Notes due 2017	New York Stock Exchange
6.5% Senior Notes due 2017	New York Stock Exchange
6.875% Senior Notes due 2018	New York Stock Exchange
7.25% Senior Notes due 2018	New York Stock Exchange
6.625% Senior Notes due 2020	New York Stock Exchange

6.875% Senior Notes due 2020	New York Stock Exchange
6.125% Senior Notes due 2021	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

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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, 2010 was approximately $13.6 billion. At February 18, 2011, there were 657,634,451 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2011 Annual Meeting of Shareholders are incorporated by reference in Part III.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

2010 ANNUAL REPORT ON FORM 10-K

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Part I

ITEM 1. *Business*
Our Business

We are the second-largest producer of natural gas and a top 20 producer of oil and natural gas liquids in the U.S. We own interests in approximately 46,000 producing natural gas and oil wells that are currently producing approximately 3.0 billion cubic feet of natural gas equivalent (bcfe) per day, 87% of which is natural gas. Our strategy is focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S., primarily in the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville and Bossier Shales in 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 and Pennsylvania. We also have substantial operations in the liquids-rich plays of the Eagle Ford Shale in South Texas, the Granite Wash, Cleveland, Tonkawa and Mississippian plays in the Anadarko Basin in western Oklahoma and the Texas Panhandle, the Niobrara Shale, Frontier and Codell plays in the Powder River and Denver Julesburg (DJ) Basins of Wyoming and Colorado and the Avalon, Bone Spring, Wolfcamp and Wolfberry plays in the Permian and Delaware Basins of West Texas and southern New Mexico, as well as various other plays, both conventional and unconventional, in the Mid-Continent, Williston Basin, Appalachian Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the U.S. We have also vertically integrated our operations and own substantial midstream, compression, drilling and oilfield service assets.

We have been developing expertise in horizontal drilling technology since shortly after our inception in 1989 and focused almost exclusively on developing natural gas properties in the U.S. from 2000 to 2008. We were one of the first companies to recognize the potential of horizontal drilling in unconventional natural gas reservoirs, especially shales, in the U.S. during the early part of the prior decade. During the past five years, we have grown from the sixth-largest natural gas producer in the U.S. to the second-largest natural gas producer, in large part as a result of our success in finding and developing unconventional natural gas assets.

In 2010, we announced that we were extending our strategy to apply the geoscientific and horizontal drilling expertise we had developed in our unconventional natural gas plays to unconventional liquids-rich reservoirs. Our goal is to reach a balanced mix of natural gas and liquids revenue as quickly as possible through organic drilling. In 2010, we invested approximately $4.7 billion, net of divestitures, primarily in liquids-rich acreage to provide the foundation for this shift towards more profitable plays. This transition is already apparent in the mix of wells we are drilling. In 2010, approximately 30% of our drilling and completion capital expenditures were allocated to liquids-rich plays, compared to 10% in 2009 and a projected 50% in 2011 and 75% in 2012. Our production of oil and natural gas liquids was 50,397 barrels (bbls) per day during 2010, a 56% increase over the average for 2009, as a result of the increased development of our unconventional liquids-rich plays. As of December 31, 2010, the company held approximately 4.3 million net leasehold acres in unconventional liquids-rich plays.

During 2010, our estimated proved reserves grew from 14.254 trillion cubic feet of natural gas equivalent (tcfe) to 17.096 tcfe, of which 90% was natural gas, 53% was proved developed and 100% was onshore in the U.S. We replaced our 1.035 tcfe of 2010 production with an estimated 3.877 tcfe of new proved reserves for a reserve replacement rate of 375%. The 2010 proved reserve movement included 5.098 tcfe of extensions, 0.006 tcfe of downward performance revisions and 0.189 tcfe of positive revisions resulting from an increase in the twelve-month trailing average natural gas and oil prices between December 31, 2009 and December 31, 2010. During 2010, we acquired 0.089 tcfe of estimated proved reserves and divested 1.493 tcfe of estimated proved reserves.

Chesapeake continued the industry s most active drilling program in 2010 and drilled 1,445 gross (938 net) operated wells and participated in another 1,586 gross (211 net) wells operated by other companies. The company s drilling success rate was 98% for both company-operated and non-operated wells. Also during 2010, we invested $4.6 billion in operated wells (using an average of 131 operated rigs) and $815 million in non-operated wells (using an average of 123 non-operated rigs) for total drilling and completion costs of $5.4 billion, net of drilling and completion carries of $1.2 billion.

Daily production for 2010 averaged 2.836 bcfe, an increase of 355 million cubic feet of natural gas equivalent (mmcfe) or 14%, over the 2.481 bcfe of daily production for 2009 and consisted of 2.534 billion cubic feet of natural gas (bcf) (89% on a natural gas equivalent basis) and 50,397 bbls (11% on a natural gas equivalent basis). This was our 21st consecutive year of sequential production growth.

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Industry Participation Agreements

During the past few years, we have entered into five significant industry participation agreements (popularly referred to as joint ventures or JVs) that monetized a portion of our investment in five of our unconventional natural gas and oil plays and provided drilling and completion carries for our retained interests. The following table provides information about our industry participation agreements as of December 31, 2010:

Shale Play	Industry Participation Agreement Partner[(a)]	Industry Participation Agreement Date	Cash Proceeds Received at Closing	Total Drilling Carries	Drilling Carries Remaining
				($ in millions)	
Haynesville and Bossier	PXP	July 2008	$ 1,650	$ 1,508[(b)]	$
Fayetteville	BP	September 2008	1,100	800	
Marcellus	STO	November 2008	1,250	2,125	1,362
Barnett	TOT	January 2010	800	1,450	889
Eagle Ford	CNOOC	November 2010	1,120	1,080	1,030
			$ 5,920	$ 6,963	$ 3,281

(a) Industry participation agreement partners include Plains Exploration & Production Company (PXP), BP America (BP), Statoil (STO), Total S.A. (TOT) and CNOOC Limited (CNOOC).

(b) In September 2009, PXP accelerated the payment of its remaining carries in exchange for an approximate 12% reduction to the remaining drilling carry obligations due to Chesapeake at that time.

In these five industry participation agreements, we received upfront cash payments of approximately $5.9 billion and future drilling cost carries of almost $7.0 billion for total consideration of $12.9 billion compared to our original cost of approximately $3.1 billion of the assets we sold. Moreover, Chesapeake retained an 80% interest in the Haynesville and Bossier Shale properties, a 75% interest in the Fayetteville Shale properties, a 67.5% interest in the Marcellus Shale properties, a 75% interest in the Barnett Shale properties and a 66.7% interest in the Eagle Ford Shale properties. Each of our industry participation partners has the right to participate proportionately with us in any additional leasehold we acquire in our respective industry participation areas. On February 11, 2011, we closed our sixth significant industry participation agreement, as described under *Recent Developments Niobrara Industry Participation Agreement* below.

Chesapeake Midstream Partners, L.P.

On August 3, 2010, Chesapeake Midstream Partners, L.P. (NYSE: CHKM), which we and Global Infrastructure Partners (GIP), a New York-based private equity fund, formed to own, operate, develop and acquire midstream assets, completed an initial public offering of common units representing limited partner interests and received net proceeds of approximately $475 million. In connection with the closing of the offering and pursuant to the terms of our contribution agreement with GIP, CHKM distributed to GIP the approximate $62 million of net proceeds from the exercise of the offering over-allotment option, and Chesapeake and GIP contributed the interests of their midstream joint venture s operating subsidiary to CHKM. Chesapeake and GIP hold 42.3% and 40.0%, respectively, of all outstanding limited partner interests, and Chesapeake and GIP each have a 50% interest in the general partner of CHKM. CHKM makes quarterly distributions to its partners, and at the current annual rate of $1.35 per unit, Chesapeake receives quarterly distributions of approximately $20 million in respect of its limited partner and general partner interests. On December 21, 2010, we sold our Springridge natural gas gathering system and related facilities in the Haynesville Shale to CHKM for $500 million and entered into ten-year gathering and compression agreements with CHKM.

Information About Us

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. From time to time, we also post announcements, updates, events, investor information and presentations on our website in addition to copies of all recent press releases. References to us , we and our in this report refer to Chesapeake Energy Corporation together with its subsidiaries.

Recent Developments

25/25 Plan

In January 2011, we updated our strategic and financial plan originally announced in May 2010 with our 25/25 Plan . The 25/25 Plan details our intention to reduce our outstanding long-term indebtedness of $13.4 billion by 25% by the end of 2012 and to reduce our planned two-year net production growth rate to 25% from the previous target range of 30% to 40%. The reduction in our projected production growth rate will be achieved by various asset monetizations that we plan to execute during the next two years, including our Fayetteville Shale and Niobrara Shale divestitures described below.

Senior Notes Offering

On February 11, 2011, we issued $1.0 billion of 6.125% Senior Notes due 2021. We used the net proceeds of $977 million from the offering to repay indebtedness outstanding under our revolving bank credit facility. The offering is a part of our 2011 liability management program, which includes extending the maturity profile of our outstanding indebtedness while also retiring approximately $2.0 to $3.0 billion of our shorter-dated senior notes as part of our 25/25 Plan.

Fayetteville Shale, Frac Tech Holdings, LLC and Chaparral Energy, Inc. Asset Monetizations

On February 21, 2011, we entered into an agreement with BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited (NYSE: BHP; ASX: BHP), to sell all of our Fayetteville Shale assets, including approximately 487,000 net acres of leasehold and producing natural gas properties and midstream assets with approximately 420 miles of pipeline, for $4.75 billion in cash before certain deductions and standard closing adjustments. In the Fayetteville Shale, we are the second-largest producer of natural gas with current net production of approximately 415 mmcfe per day. Estimated proved reserves attributable to the Fayetteville Shale as of December 31, 2010 were 2.4 tcfe, or approximately 14% of our total proved reserves. As part of the transaction, we have agreed to provide essential services for up to one year for BHP Billiton for an agreed-upon fee. Closing of the transaction is subject to customary conditions, including filings under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and with the Committee on Foreign Investment in the United States. Closing is expected to occur in the first half of 2011. In addition, we have commenced efforts to monetize our equity investments in Frac Tech Holdings, LLC and Chaparral Energy, Inc. We own a 25.8% equity interest in Frac Tech and a 20.0% equity interest in Chaparral. These sales are subject to changes in market conditions and other factors, and there can be no assurance that we will complete either or both of these transactions on a timely basis or at all.

Niobrara Industry Participation Agreement

On February 16, 2011, we entered into an industry participation agreement with a wholly owned U.S. subsidiary of CNOOC Limited (CNOOC) to develop our Niobrara Shale play in the DJ and Powder River Basins in northeast Colorado and southeast Wyoming. Under the terms of the industry participation agreement, CNOOC acquired a 33.3% undivided interest in approximately 800,000 net acres of our leasehold. We received $570 million in cash at closing, and CNOOC has agreed to fund 66.7% of our share of drilling and completion costs until an additional $697 million has been paid, which we expect to occur by year-end 2014. In addition, CNOOC has the right to a 33.3% participation in any additional leasehold we acquire in the area at cost plus a fee.

Business Strategy

Since our inception in 1989, Chesapeake s goal has been to create value for investors by building one of the largest onshore resource bases in the U.S. by focusing our technical and land acquisition skills on developing unconventional resource plays onshore in the U.S. From 2000 through 2008, our focus was on finding and developing natural gas resource plays. In the past two years, our focus has shifted to finding and developing plays with oil and natural gas liquids (NGL) since oil and NGLs are more highly valued in the U.S. than natural gas and technological and knowledge advances have enabled us to pursue these new plays more economically. 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 in areas with large unconventional accumulations of natural gas, oil and NGLs. We are currently utilizing 157 operated drilling rigs and 106 non-operated drilling rigs to conduct the most active drilling program in the U.S. We are active in most of the nation s major unconventional plays, where we drill more

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horizontal wells than any other company in the industry. For many years, we have been actively investing large amounts of capital in leasehold, 3-D seismic information and human resources 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 21 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 new horizontal drilling and completion techniques would enable development of previously uneconomic natural gas and oil reservoirs and that, as a consequence, various shale and other unconventional formations could be recognized and developed as potentially prolific reservoirs rather than just as source rocks for conventional reservoirs. In response to our early recognition of these trends, we have proactively hired thousands of new employees and have built what we believe is the largest combined inventory of onshore leasehold and 3-D seismic in the U.S. These are 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. Recognizing that better horizontal drilling and completion technologies, when applied to various new unconventional plays, would likely create a unique opportunity to capture decades worth of drilling opportunities, we embarked on an aggressive lease acquisition program, which we have referred to as the gas shale land grab of 2006 through 2008 and the unconventional oil land grab of 2009 and 2010. We believed that the winner of these land grabs would enjoy competitive advantages for decades to come as other companies would be locked out of the best new unconventional resource plays in the U.S. We believe that we have executed our land acquisition strategy with particular distinction. At December 31, 2010, we held approximately 13.2 million net acres of onshore leasehold in the U.S. and have identified approximately 38,000 drilling opportunities on this leasehold. We believe this extensive backlog of drilling, more than ten years worth at current drilling levels, provides unmistakable evidence of our future growth capabilities. We further believe that the majority of the U.S.-based land acquisition phase is now complete and are forecasting to spend significantly less on new leasehold in the coming periods as compared to recent years.

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 and oil that might otherwise remain undiscovered and to drill our horizontal wells more accurately inside the targeted 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 5% of the nation s natural gas and oil, drill approximately 9% 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 wells drilled through unconventional formations on a proprietary basis, then identify new plays and leasing opportunities ahead of our competition and reduce the likelihood of investing in plays that ultimately are not commercial. It also allows us to design fracture stimulation procedures that might work most productively in the unconventional formations that we target.

Build Operating Focus and Scale. We believe one of the keys to success in the U.S. exploration and production industry is to build significant operating scale in 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 virtually all of the nation s major unconventional resource plays and avoiding investing offshore and internationally, we will continue to achieve the significant benefits of focus and scale.

Focus on Low Costs and Vertical Integration. By minimizing lease operating costs and general and administrative expenses through focused activities, vertical integration and increasing 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 and extensive access to oilfield services and to 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, compression and trucking service operations and in our midstream gathering operations that create substantial benefits from vertical integration. In 2011 and 2012, we also intend to make significant investments in building our capability to hydraulically fracture our wells. As of December 31, 2010, we operated approximately 26,000 of our 46,000 wells, which delivered approximately 80% of our daily production volume. This large percentage of operated properties provides us with a high degree of operational 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 often subject to significant price volatility. We intend to 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. Assuming future NYMEX natural gas settlement prices average $4.50 per mcf for 2011, and including the effect of the company s open derivatives as of February 22, 2011, closed contracts and previously collected call premiums, the company estimates its average natural gas price will be $5.98 per mcf for 2011. This estimate does not include the effect of basis differentials and gathering costs.

Form Value-Creating Industry Participation Agreements. Since 2008, the company has entered into six significant industry participation agreements. Through these agreements, the company has collaborated with other leading energy companies to accelerate the development of the company s properties in the Haynesville and Bossier Shales, the Fayetteville Shale, the Marcellus Shale, the Barnett Shale, the Eagle Ford Shale and the Niobrara Shale. Including the Niobrara agreement, which we entered into on February 16, 2011, we have sold leasehold and producing property assets with an original cost to us of approximately $3.4 billion to our partners for $6.5 billion of total cash consideration and $7.7 billion of drilling cost carries while retaining a majority interest in each play. The remaining drilling cost carries of approximately $4.0 billion (including the Niobrara industry participation agreement), as of December 31, 2010, will be extremely valuable in the years ahead by enabling the company to develop reserves in these unconventional plays at greatly reduced costs. We are also considering opportunities for additional industry participation agreements to develop certain of our other properties. Additionally, in 2009 we formed a joint venture with GIP for certain of our midstream assets in the Barnett Shale and Mid Continent. We and GIP have since sold a portion of the equity in this venture to the public through a master limited partnership, Chesapeake Midstream Partners, L.P.

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 opportunities and extremes of natural gas and oil prices to create the nation s second-largest producer of natural gas, a top 20 producer of oil and natural gas liquids, the most active driller of new wells and an employer of approximately 10,000 people and an indirect employer of tens of thousands more. 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. Our 2011 strategic and financial plan calls for a 25% reduction in our long-term debt while growing net natural gas and oil production by 25% by the end of 2012. We believe this reduction of our debt and continued growth in our asset base will lead to our long-term debt to reserves ratio (long-term debt net of cash divided by our estimated proved reserves) decreasing to less than $0.50 per mcfe at year-end 2012 compared to $0.73 per mcfe at year-end 2010. We believe the reduction in our debt will lower our borrowing costs, increase our financial flexibility and increase our stock market valuation. Additionally, we believe our improved credit metrics described above will lead to a more favorable debt rating by the major ratings agencies.

Operating Areas

Chesapeake focuses its exploration, development, acquisition and production efforts in the nine operating areas described below.

Mid-Continent (principally the Anadarko Basin). Chesapeake s Mid-Continent proved reserves of 4.867 tcfe represented 28% of our total proved reserves as of December 31, 2010. During 2010, this area produced 316 bcfe, or 31%, of our 2010 production, and we invested approximately $1.1 billion to drill 596 (212 net) wells in the Mid-Continent. For 2011, we anticipate spending approximately $1.7 billion, or 33% of our total budget, for exploration and development activities in the Mid-Continent region, with a continuing focus on the Granite Wash and an increasing focus on the Tonkawa, Cleveland and Mississippian liquids-rich unconventional plays.

Haynesville Shale (including the Bossier Shale). Chesapeake s Haynesville Shale proved reserves represented 3.583 tcfe, or 21%, of our total proved reserves as of December 31, 2010. During 2010, the Haynesville Shale assets produced 239 bcfe, or 23%, of our total production, and we invested approximately $2.0 billion to drill 500 (202 net) wells in the Haynesville Shale. For 2011, we anticipate spending approximately $1.65 billion, or 32% of our total budget, for exploration and development activities in the Haynesville Shale.

Barnett Shale. Chesapeake s Barnett Shale proved reserves represented 3.063 tcfe, or 18%, of our total proved reserves as of December 31, 2010. During 2010, the Barnett Shale assets produced 175 bcfe, or 17%, of our total production, and we invested approximately $570 million to drill 503 (287 net) wells in the Barnett Shale, net of $483 million in drilling and completion cost carries paid by our industry participation partner, Total, in 2010. For 2011, we anticipate spending approximately $350 million, or 7% of our total budget, for exploration and development activities, net of carries, in the Barnett Shale. Total is obligated to fund 60% of our share of future drilling and completion costs until $1.45 billion has been paid, which we expect to occur by year-end 2013. Of the $889 million drilling cost carry remaining at December 31, 2010, we expect approximately $375 million will be utilized in 2011.

Fayetteville Shale. Chesapeake s Fayetteville Shale proved reserves represented 2.396 tcfe, or 14%, of our total proved reserves as of December 31, 2010. During 2010, the Fayetteville Shale assets produced 137 bcfe, or 13%, of our total production, and we invested approximately $725 million to drill 775 (157 net) wells in the Fayetteville Shale. On February 21, 2011, we entered into an agreement with a wholly owned subsidiary of BHP Billiton Limited to sell the assets for $4.75 billion, before certain deductions and standard closing adjustments.

Permian and Delaware Basins. Chesapeake s Permian and Delaware Basin proved reserves represented 774 bcfe, or 4%, of our total proved reserves as of December 31, 2010. During 2010, the Permian assets produced 61 bcfe, or 6%, of our total production, and we invested approximately $396 million to drill 156 (84 net) wells in the Permian and Delaware Basins. For 2011, we anticipate spending approximately $425 million, or 8% of our total budget, for exploration and development activities in the Permian and Delaware Basins, with an increased focus on the Bone Spring, Avalon, Wolfcamp and Wolfberry liquids-rich unconventional plays.

Marcellus Shale. Chesapeake s Marcellus Shale proved reserves represented 860 bcfe, or 5%, of our total proved reserves as of December 31, 2010. During 2010, the Marcellus Shale assets produced 53 bcfe, or 5%, of our total production, and we invested approximately $380 million to drill 329 (135 net) wells in the Marcellus Shale, net of $601 million in drilling and completion cost carries paid by our industry participation partner, Statoil, in 2010. For 2011, we anticipate spending approximately $325 million, or 6% of our total budget, for exploration and development activities, net of carries, in the Marcellus Shale. Statoil will pay 75% of our drilling and completion costs in the play until $2.125 billion has been paid, which we expect to occur by year-end 2012. Of the $1.362 billion drilling cost carry remaining at December 31, 2010, we expect approximately $660 million will be utilized in 2011.

Eagle Ford Shale. Chesapeake s Eagle Ford Shale proved reserves represented 108 bcfe, or 1%, of our total proved reserves as of December 31, 2010. During 2010, the Eagle Ford Shale assets produced 2 bcfe, or a nominal amount, of our total production, and we invested approximately $243 million to drill 82 (48 net) wells in the Eagle Ford Shale, net of $67 million in drilling and completion cost carries paid by our industry participation partner, CNOOC, in 2010. For 2011, we anticipate spending approximately $375 million, or 7% of our total budget, for exploration and development activities, net of carries, in the Eagle Ford Shale. CNOOC will pay 75% of our drilling and completion costs in the play until $1.08 billion has been paid, which we expect to occur by year-end 2012. Of the $1.030 billion drilling cost carry remaining at December 31, 2010, we expect approximately $775 million will be utilized in 2011.

Rockies/Williston Basin. Chesapeake s Rocky Mountains/Williston Basin proved reserves of 7 bcfe represented a nominal amount of our total proved reserves as of December 31, 2010. During 2010, this area produced 1 bcfe, or a nominal amount of our 2010 production, and we invested approximately $77 million to drill 32 (13 net) wells in the Rocky Mountains/Williston Basin. For 2011, we anticipate spending approximately $225 million, or 4% of our total budget, for exploration and development activities, net of carries, in the Rocky Mountains/Williston Basin. CNOOC will pay 67% of our drilling and completion costs in the play until $697 million has been paid, which we expect to occur by year-end 2014. Of the $697 million of drilling cost carry remaining, we expect approximately $150 million will be utilized in 2011.

Other. Chesapeake s other proved reserves represented 1.438 tcfe, or 9%, of our total proved reserves as of December 31, 2010. During 2010, assets categorized as other produced 51 bcfe, or 5%, of our total production, and we invested approximately $69 million to drill 58 (11 net) wells in our other assets. For 2011, we anticipate spending approximately $125 million, or 2% of our total budget, for exploration and development activities in this area.

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Well Data

At December 31, 2010, we had interests in approximately 45,800 gross (22,600 net) productive wells, including properties in which we held an overriding royalty interest, of which 38,900 gross (20,600 net) were classified as primarily natural gas productive wells and 6,900 gross (2,000 net) were classified as primarily oil productive wells. Chesapeake operates approximately 25,750 of its 45,800 productive wells. During 2010, we drilled 1,445 gross (938 net) wells and participated in another 1,586 gross (211 net) wells operated by other companies. We operate approximately 80% of our current daily production volumes.

Drilling Activity

The following table sets forth the wells we drilled or participated in 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.

	2010				2009				2008			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	2,721	99	1,031	99	1,971	98	875	99	3,479	99	1,650	99
Dry	30	1	12	1	33	2	8	1	40	1	13	1
Total	2,751	100%	1,043	100%	2,004	100%	883	100%	3,519	100%	1,663	100%
Exploratory:												
Productive	265	95	99	93	196	97	115	96	142	90	63	90
Dry	15	5	7	7	6	3	5	4	15	10	7	10
Total	280	100%	106	100%	202	100%	120	100%	157	100%	70	100%

The following table shows the wells we drilled or participated in by area:

	2010		2009		2008	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Mid-Continent	596	212	386	144	1,515	542
Haynesville/Bossier Shale	500	202	337	163	81	42
Barnett Shale	503	287	417	339	776	600
Fayetteville Shale	775	157	774	209	814	220
Permian and Delaware Basins	156	84	93	42	165	95
Marcellus Shale	329	135	149	74	32	23
Eagle Ford Shale	82	48				
Rockies/Williston Basin	32	13				
Other	58	11	50	32	293	211
Total	3,031	1,149	2,206	1,003	3,676	1,733

At December 31, 2010, we had 221 (86 net) wells in process.

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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,		
	2010	2009	2008
Net Production[(a)]:			
Natural gas (bcf)	924.9	834.8	775.4
Oil (mmbbl)[(b)]	18.4	11.8	11.2
Natural gas equivalent (bcfe)	1,035.2	905.5	842.7
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 3,169	$ 2,635	$ 6,003
Natural gas derivatives realized gains (losses)	1,982	2,313	267
Natural gas derivatives unrealized gains (losses)	425	(492)	521
Total natural gas sales	5,576	4,456	6,791
Oil sales[(b)]	1,079	656	1,066
Oil derivatives realized gains (losses)	74	33	(275)
Oil derivatives unrealized gains (losses)	(1,082)	(96)	276
Total oil sales	71	593	1,067
Total natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858
Average Sales Price (excluding gains (losses) on derivatives)[(a)]:			
Natural gas ($ per mcf)	$ 3.43	$ 3.16	$ 7.74
Oil ($ per bbl)	$ 58.67	$ 55.60	$ 95.04
Natural gas equivalent ($ per mcfe)	$ 4.10	$ 3.63	$ 8.39
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 5.57	$ 5.93	$ 8.09
Oil ($ per bbl)	$ 62.71	$ 58.38	$ 70.48
Natural gas equivalent ($ per mcfe)	$ 6.09	$ 6.22	$ 8.38
Other Operating Income[(c)] ($ per mcfe):			
Marketing, gathering and compression net margin	$ 0.12	$ 0.16	$ 0.11
Service operations net margin	$ 0.03	$ 0.01	$ 0.04
Expenses ($ per mcfe):			
Production expenses[(a)]	$ 0.86	$ 0.97	$ 1.05
Production taxes	$ 0.15	$ 0.12	$ 0.34
General and administrative expenses	$ 0.44	$ 0.38	$ 0.45
Natural gas and oil depreciation, depletion and amortization	$ 1.35	$ 1.51	$ 2.34
Depreciation and amortization of other assets	$ 0.21	$ 0.27	$ 0.21
Interest expense[(d)]	$ 0.08	$ 0.22	$ 0.22

(a) Our production, prices and production expenses are disclosed by region under Results of Operations in Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations*.

(b) Includes NGLs.

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

(d) 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.

Natural Gas and Oil Reserves

The tables below set forth information as of December 31, 2010 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 future income taxes (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. All of our estimated natural gas and oil reserves are located within the United States.

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	December 31, 2010		
	Natural Gas (bcf)	Oil (mmbbl)[a]	Total (bcfe)[b]
Proved developed	8,246	149.3	9,143
Proved undeveloped	7,209	124.1	7,953
Total proved	15,455	273.4	17,096

	Proved Developed	Proved Undeveloped ($ in millions)	Total Proved
Estimated future net revenue[c]	$ 23,322	$ 14,308	$ 37,630
Present value of estimated future net revenue[c]	$ 11,423	$ 3,723	$ 15,146
Standardized measure[c][d]			$ 13,183

	Natural Gas (bcf)	Oil (mmbbl)[a]	Natural Gas Equivalent (bcfe)[b]	Percent of Proved Reserves	Present Value ($ in millions)
Mid-Continent	3,704	193.7	4,867	28%	$ 6,588
Haynesville/Bossier Shale	3,583		3,583	21	2,408
Barnett Shale	2,995	11.2	3,063	18	1,299
Fayetteville Shale	2,396		2,396	14	1,457
Permian and Delaware Basins	515	43.1	774	4	1,058
Marcellus Shale	801	10.0	860	5	1,497
Eagle Ford Shale	58	8.2	108	1	245
Rockies/Williston Basin	3	0.8	7		15
Other	1,400	6.4	1,438	9	579
Total	15,455	273.4	17,096	100%	$ 15,146[c]

(a) Includes NGLs.

(b) Natural gas equivalent based on six mcf of natural gas to one barrel of oil.

(c) 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 under existing economic conditions at December 31, 2010. For the purpose of determining prices , we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2010. The prices used in our reserve reports were $4.38 per mcf of natural gas and $79.42 per barrel of oil, before price differential adjustments. 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, 2010. 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. The present value of estimated future net revenue differs from the standardized measure only because the former does not include the effects of estimated future income tax expenses ($2.0 billion as of December 31, 2010).

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. 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.

(d) 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, 2010, our reserve estimates included 7.953 tcfe of reserves classified as proved undeveloped (PUD), compared to 5.923 tcfe as of December 31, 2009. Presented below is a summary of changes in our proved undeveloped reserves for 2010.

	Total (bcfe)
Proved undeveloped reserves, beginning of period	5,923
Extensions, discoveries and other additions	3,210
Revisions of previous estimates	(365)
Developed	(603)
Sale of reserves-in-place	(233)
Purchase of reserves-in-place	21
Proved undeveloped reserves, end of period	7,953

As of December 31, 2010, there were no PUDs that had remained undeveloped for five years or more. We invested approximately $789 million, net of drilling cost carries, in 2010 to convert 603 bcfe of PUDs to proved developed reserves. In 2011, we estimate that we will invest approximately $1.9 billion, net of drilling cost carries, for PUD conversion.

The future net revenue attributable to our estimated proved undeveloped reserves of $14.308 billion at December 31, 2010, and the $3.723 billion present value thereof, has been calculated assuming that we will expend approximately $10.7 billion to develop these reserves. Net of drilling cost carries, we have projected to incur $1.9 billion in 2011, $1.4 billion in 2012, $2.1 billion in 2013 and $5.3 billion in 2014 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.

The SEC s modernized rules for reporting oil and gas reserves, which became effective December 31, 2009, allow the booking of proved undeveloped reserves at locations greater distances from producing wells than immediate offsets. All proved reserves are required to meet reasonable certainty standards; thus, locations more than direct offsets to producing wells must be shown to be underlain by the productive formation. Reasonable certainty also requires that the formation is continuous between the producing wells and the PUD locations and that the PUDs are economically viable. We booked PUDs more than directly offsetting producing wells in three resource plays, the Barnett Shale, the Fayetteville Shale and the Haynesville Shale. In all other areas we restricted PUD locations to immediate offsets to producing wells. Within the Barnett, Fayetteville and Haynesville Shale plays, we used both public and proprietary geologic data to establish continuity of the formation and its producing properties. This included seismic data and interpretations (2-D, 3-D and micro seismic); open hole log information (both vertical and horizontally collected) and petrophysical analysis of the log data; mud logs; gas sample analysis; drill cutting samples; measurements of total organic content; thermal maturity; sidewall cores; whole cores and data measured from our internal core analysis facility. After the geologic area was shown to be continuous, statistical analysis of existing producing wells was conducted to generate an area of reasonable certainty at distances from established production. Undrilled locations within this proved area could be booked as PUDs. However, due to other factors and requirements of the modernized rules, numerous locations within the proved area of these three statistically evaluated plays have not yet been booked as PUDs.

Our annual net decline rate on producing properties is projected to be 30% from 2011 to 2012, 19% from 2012 to 2013, 14% from 2013 to 2014, 12% from 2014 to 2015 and 10% from 2015 to 2016. Of our 9.143 tcfe of proved developed reserves as of December 31, 2010, 950 bcfe were non-producing.

Chesapeake s ownership interest used in calculating proved reserves and the associated estimated future net revenue was determined after giving effect to the assumed maximum participation by other parties to our farmout and participation agreements. The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for natural gas and oil production sold subsequent to December 31, 2010. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices.

The company s estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2010, 2009 and 2008, and the changes in quantities and standardized measure

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

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.

Reserves Price Sensitivity

An increase or decrease in price of $0.10 per mcf for natural gas and $1.00 per barrel for oil would result in a corresponding change in the December 31, 2010 present value of estimated future net revenue of our proved reserves of approximately $600 million and $90 million, respectively. The estimated future net revenue used in this analysis does not include the effects of future income taxes or hedging.

Chesapeake s management uses forward-looking market-based data in developing its drilling plans, assessing its capital expenditure needs and projecting future cash flows. We believe that using the 10-year average future NYMEX strip prices yields a better indication of the likely economic producibility of proved reserves than the trailing average 12-month price required by the SEC s reserves rules or a period-end spot price, as used under the SEC rules before December 31, 2009. Reserve volumes represent estimated production to be sold in the future. Futures prices, such as the 10-year average NYMEX strip prices, represent an unbiased consensus estimate by market participants about the likely prices to be received for our future production. We hedge substantial amounts of future production based on futures prices. While historical data, such as the trailing 12-month average price required by the SEC s reporting rule, facilitate comparisons of proved reserves from company to company and may be helpful in discerning trends, such as price-related effects on end-user demand, the price at which we can sell our production in the future is by far the major determinant of the likely economic producibility of our reserves. A 12-month average price adjusts slowly to falling or rising prices, further detracting from its usefulness as a predictor of the prices at which future production will actually be sold.

The table below compares our estimated proved reserves and associated present value (discounted at an annual rate of 10%) of estimated future revenue before income tax using the 2010 12-month average prices of $4.38 per mcf and $79.42 per bbl, before price differential adjustments, reflected in our reported reserve estimates and the 10-year average future NYMEX strip prices as of December 31, 2010, which were $5.67 per mcf and $93.53 per barrel, before price differential adjustments. There is no change to our cost or other assumptions between this higher price scenario and those used in the estimation of our reported reserves.

	December 31, 2010			
	Gas (bcf)	Oil (mmbbl)[a]	Total (bcfe)	Present Value ($ in millions)
2010 12-month average prices (SEC)[b]	15,455	273	17,096	$ 15,146
10-year average future NYMEX strip prices as of December 31, 2010[c]	15,946	276	17,605	$ 21,715

(a) Includes NGLs.

(b) Volumes represent proved reserves as defined in Rule 4-10(a)(22) of Regulation S-X.

(c) Volumes do not represent proved reserves as defined in Rule 4-10(a)(22) of Regulation S-X.

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Reserves Estimation

Chesapeake s Reservoir Engineering Department prepared approximately 22% of the proved reserves estimates (by volume) disclosed in this report 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. The department currently has a total of 97 full-time employees, consisting of 58 degreed engineers (10 serving in management capacities), 37 engineering technicians with a minimum of a four-year degree in mathematics, economics, finance or other business/science field, and 2 administrative persons. Twelve of our engineers are registered professional engineers with various state board certifications. The department collectively has approximately 1,400 years of engineering industry experience. Chesapeake maintains a continuous education program for engineers and technicians on new technologies and industry advancements and also offers refresher training on basic skill sets.

Chesapeake maintains internal controls such as the following to ensure the reliability of reserves estimations:

- No employee s compensation is tied to the amount of reserves booked.
- We follow comprehensive SEC-compliant internal policies to determine and report proved reserves. Reserves estimates are made by experienced reservoir engineers or under their direct supervision.
- The Reservoir Engineering Department reviews all the company s reported proved reserves at the close of each quarter.
- Each quarter, Reservoir Engineering Department managers, the Vice President of Reservoir Engineering, the Senior Vice President of Production and the Chief Operating Officer review all significant reserves changes and all new proved undeveloped reserves additions.
- The Reservoir Engineering Department reports independently of any of our operating divisions.

Chesapeake s Vice President of Reservoir Engineering is the technical person primarily responsible for overseeing the preparation of the company s reserve estimates. His qualifications include the following:

- 35 years of practical experience in petroleum engineering with 32 years of this experience being in the estimation and evaluation of reserves
- certified professional engineer in the state of Oklahoma
- Bachelor of Science degree in Petroleum Engineering
- member in good standing of the Society of Petroleum Engineers

We engaged four third-party engineering firms to prepare portions of our reserves estimates comprising approximately 78% of our estimated proved reserves (by volume) at year-end 2010. The portion of our estimated proved reserves prepared by each of our third-party engineering firms as of December 31, 2010 is presented below.

	% Prepared (by Volume)	Principal Properties
Netherland, Sewell & Associates, Inc.	58%	Barnett Shale Fayetteville Shale Haynesville Shale Mid-Continent (portions) Permian and Delaware Basins Ark-La-Tex (portions)
Lee Keeling and Associates, Inc.	7%	Mid-Continent South Texas/ Texas Gulf Coast (portions) Eagle Ford Shale
Data and Consulting Services, Division of Schlumberger Technology Corporation	7%	Marcellus Shale Other Appalachian Basin
Ryder Scott Company, L.P.	6%	Mid-Continent (portions)

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Copies of the reports issued by the engineering firms are filed with this report as Exhibits 99.1 - 99.4. The qualifications of the technical person at each of these firms primarily responsible for overseeing his firm s preparation of the company s reserve estimates are set forth below.

Netherland, Sewell & Associates, Inc.:

- over 28 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves
- a registered professional engineer in the state of Texas
- Bachelor of Science Degree in Petroleum Engineering

Lee Keeling and Associates, Inc.:

- over 45 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves
- a certified professional engineer in the state of Oklahoma
- Bachelor of Science Degree in Petroleum Engineering

Data and Consulting Services, Division of Schlumberger Technology Corporation:

- over 20 years of practical experience in petroleum geology and in the estimation and evaluation of reserves
- registered professional geologist license in the commonwealth of Pennsylvania
- certified petroleum geologist of the American Association of Petroleum Geologists
- Bachelor of Science Degree in Geological Sciences

Ryder Scott Company, L.P.:

- over 30 years of practical experience in the estimation and evaluation of reserves
- registered professional engineer in the state of Texas
- Bachelor of Science Degree in Electrical Engineering

member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers

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:

	December 31, 2010	2009	2008
	($ in millions)		
Development and exploration costs:			
Development drilling[a]	$ 4,739	$ 2,729	$ 5,185
Exploratory drilling	691	651	612
Geological and geophysical costs[b][c]	181	162	314
Asset retirement obligation and other	2	(2)	10
	5,613	3,540	6,121
Acquisition costs:			
Unproved properties[d]	6,953	2,793	8,250
Proved properties	243	61	355
Deferred income taxes			13
	7,196	2,854	8,618
Proceeds from divestitures:			
Unproved properties	(1,524)	(1,265)	(5,302)
Proved properties	(2,876)	(461)	(2,433)
	(4,400)	(1,726)	(7,735)
Total	$ 8,409	$ 4,668	$ 7,004

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(a) Includes capitalized internal costs of $367 million, $337 million and $326 million, respectively.

(b) Includes capitalized internal costs of $16 million, $22 million and $26 million, respectively.

(c) Includes $24 million, $29 million and $25 million of related capitalized interest, respectively.

(d) Includes $687 million, $598 million and $561 million of related capitalized interest, respectively.

Our development costs included $789 million, $621 million and $1.5 billion in 2010, 2009 and 2008, 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 2010 by operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development[(a)]	Acquisition of Unproved Properties[(b)]	Acquisition of Proved Properties	Sales of Unproved Properties	Sales of Proved Properties	Total
				($ in millions)				
Mid-Continent	596	212	$ 1,121	$ 547	$ 90	$	$	$ 1,758
Haynesville/ Bossier Shale	500	202	2,032	411	66	(57)	(4)	2,448
Barnett Shale	503	287	570	216		(38)	(1,938)	(1,190)
Fayetteville Shale	775	157	725	74				799
Permian and Delaware Basins	156	84	396	41	2	(4)	(560)	(125)
Marcellus Shale	329	135	380	1,114	2	(396)		1,100
Eagle Ford Shale	82	48	243	1,863	73	(1,029)	(73)	1,077
Rockies/ Williston Basin	32	13	77	912	8			997
Other	58	11	69	1,775	2		(301)	1,545
Total	3,031	1,149	$ 5,613	$ 6,953	$ 243	$ (1,524)	$ (2,876)	$ 8,409

(a) Includes $383 million of capitalized internal costs and $24 million of related capitalized interest.

(b) Includes $687 million of related capitalized interest.

Acreage

We actively acquire new leases, most of which have a three-to-five year term. Managing lease expirations to ensure that we do not experience unintended material expirations is an important part of our business. Our leasehold management efforts include scheduling our drilling to establish production in paying quantities in order to hold leases by production, timely exercising our contractual rights to pay delay rentals to extend the terms of leases we value, planning leasehold asset sales and industry participation transactions to high-grade our lease inventory or to raise capital for additional development and letting some low-value leases expire. We maintain a very large drilling program that is rigorously scheduled to lock in our acreage with the highest prospective value. The fact that we control a substantial rig fleet and other service operations gives us a high degree of confidence that we will be able to execute our drilling plans. We have determined that the amount of undeveloped leasehold that we reasonably believe will be abandoned or allowed to expire at the end of the lease term is immaterial to our operations.

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The following table sets forth as of December 31, 2010 the gross and net leasehold 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 acreage which have not been exercised.

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
	(in thousands)					
Mid-Continent	4,469	2,252	2,720	1,627	7,189	3,879
Haynesville/Bossier Shale	375	269	405	258	780	527
Barnett Shale	235	132	166	85	401	217
Fayetteville Shale	414	188	955	413	1,369	601
Permian and Delaware Basins	364	212	1,567	992	1,931	1,204
Marcellus Shale	408	211	2,972	1,460	3,380	1,671
Eagle Ford Shale	45	25	852	440	897	465
Rockies/Williston Basin	41	19	1,456	832	1,497	851
Other	2,182	1,736	3,437	2,062	5,619	3,798
Total	8,533	5,044	14,530	8,169	23,063	13,213

Marketing, Gathering and Compression

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, its partners and other producers. We attempt to enhance the value of our natural gas and oil production by aggregating volumes to be sold to various intermediary markets, end markets 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 after transportation and processing of our natural gas. 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 2011, approximately 80% of our natural gas production was sold under short-term contracts at market-sensitive prices. No customer accounted for more than 10% of total revenues (excluding gains (losses) on derivatives) in 2010.

Our marketing activities, along with our midstream gathering and compression activities discussed below, constitute a reportable segment under accounting guidance for disclosure about segments of an enterprise and related information. See Note 16 of the notes to our consolidated financial statements in Item 8 of this report.

Midstream Gathering Operations

Chesapeake invests in gathering systems and processing facilities to complement our natural gas operations in regions where we have significant production and additional infrastructure is required. By doing so, we are better able to manage the value received for and the costs of, gathering, treating and processing natural gas. These systems are designed primarily to gather company production for delivery into major intrastate or interstate pipelines. In addition, our midstream business provides services to third-party customers. Chesapeake generates revenues from its gathering, treating and compression activities through fixed-rate fee structures. The company also processes a portion of its natural gas at various third-party plants.

Our midstream assets are held and operated by our wholly owned subsidiary, Chesapeake Midstream Development, L.P. (CMD), and its subsidiaries. In September 2009, we formed a joint venture with GIP to own and operate natural gas midstream assets. As part of the transaction, we contributed certain natural gas gathering systems

that had been held by CMD and its subsidiaries to a new entity, Chesapeake Midstream Partners, L.L.C. (CMP), and

GIP purchased a 50% interest in CMP for $588 million in cash. The assets we contributed to the joint venture were substantially all of our midstream assets in the Barnett Shale and also the majority of our non-shale midstream assets in the Arkoma, Anadarko, Delaware and Permian Basins. Together, these assets constituted approximately 57% of our total midstream assets as of September 30, 2009.

On August 3, 2010, Chesapeake Midstream Partners, L.P. (NYSE: CHKM), which we and GIP formed to own, operate, develop and acquire midstream assets, completed an initial public offering of 24,437,500 common units (including 3,187,500 common units issued pursuant to the exercise of the underwriters over-allotment option on August 3, 2010) representing limited partner interests and received net offering proceeds of approximately $475 million at an initial offering price of $21.00 per unit. In connection with the closing of the offering and pursuant to the terms of our contribution agreement with GIP, CHKM distributed to GIP the approximate $62 million of net proceeds from the exercise of the over-allotment option. In connection with the closing of the offering, Chesapeake and GIP contributed the interests of the midstream joint venture s operating subsidiary to CHKM. CHKM is continuing the business that had been conducted by the joint venture. Common units owned by public security holders represent 17.7% of all outstanding limited partner interests, and Chesapeake and GIP hold 42.3% and 40.0%, respectively, of all outstanding limited partner interests. The limited partners, collectively, have a 98.0% interest in CHKM, and the general partner, which is owned and controlled 50/50 by Chesapeake and GIP, has a 2.0% interest in CHKM.

Subsidiaries of CMD continue to operate our midstream assets outside of CHKM. The CMD systems are located in Oklahoma, Texas, Colorado, New Mexico, New York, Ohio, Louisiana, Arkansas, Pennsylvania, Wyoming and West Virginia and consist of approximately 1,750 miles of gathering pipelines, servicing over 1,150 natural gas wells. These include natural gas gathering assets in the Fayetteville Shale, Marcellus Shale and other areas in Appalachia. Compared to the Barnett Shale and Mid-Continent areas where the CHKM midstream assets are located, these are less developed areas and will require significant build-out capital expenditures. As described in *Recent Developments*, in February 2011, we agreed to sell the CMD midstream assets in the Fayetteville Shale in a transaction expected to close in the first half of 2011. A source of liquidity for CMD s business is the $300 million revolving credit facility described under *Liquidity and Capital Resources* in Item 7 below. On December 21, 2010, CMD sold its Springridge natural gas gathering system and related facilities in the Haynesville Shale to CHKM for $500 million. In connection with this transaction, CHKM and certain Chesapeake subsidiaries entered into ten-year gathering and compression agreements covering upstream assets within an area of dedication around the existing pipeline system. The gathering and compression agreements are similar to the previously existing gathering agreement between Chesapeake and CHKM and include a minimum volume commitment and periodic rate redetermination.

Compression

Since 2003, 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 natural gas primarily produced from Chesapeake-operated wells. In a series of transactions since 2007, MidCon sold a significant portion of its compressor fleet, consisting of 2,234 compressors, for $517 million and entered into a master lease agreement. These transactions were recorded as sales and operating leasebacks.

Service Operations

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 wholly owned drilling subsidiary, now Nomac Drilling, L.L.C., with an investment of $26 million to build and refurbish five drilling rigs. As of December 31, 2010, Chesapeake had invested approximately $1.1 billion to build or acquire 105 drilling rigs, which are utilized primarily to drill Chesapeake-operated wells. In a series of transactions since 2006, our drilling subsidiaries sold 86 rigs for $717 million and subsequently leased back the rigs through 2018. These transactions were recorded as sales and operating leasebacks. The drilling rigs have depth ratings between 3,000 and 25,000 feet and range in drilling horsepower from 450 to 2,000. These drilling rigs are currently operating in Oklahoma, Texas, Arkansas, Louisiana and Appalachia. Nomac Drilling, L.L.C. is the fifth 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, 2010, our fleet included 208 trucks and 22 cranes, which mainly service the Mid-Continent, Barnett Shale and Appalachian regions.

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 liquified natural gas (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. Other activities subject to regulation include, but are not limited to:

- 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

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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 natural gas, oil and natural gas liquids, 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.

Federal, state and local laws may require us 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 releases 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. CERCLA and analogous state laws also authorize the U.S. Environmental Protection Agency (EPA), state environmental agencies and, in some cases, third parties to take action to prevent or respond to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such actions.

Other federal and state laws, in particular the federal Resource Conservation and Recovery Act, regulate hazardous and non-hazardous wastes. Under a longstanding legal framework, certain wastes generated by our natural gas and oil operations are not subject to federal regulations governing hazardous wastes, though they may be regulated under other federal and state laws. These wastes may in the future be designated as hazardous wastes and may thus become subject to more rigorous and costly compliance and disposal requirements.

Vast quantities of natural gas and oil deposits exist in deep shale and other formations. It is customary in our industry to recover natural gas and oil from these deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations underground where water, sand and other additives are pumped under high pressure into a shale formation. These formations are generally geologically separated and isolated from fresh ground water supplies by 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 aquifers. Legislative and regulatory efforts at the federal level and in some states have sought to render permitting and compliance requirements more stringent for hydraulic fracturing. If passed into law, such efforts could have an adverse effect on our operations.

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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 that we are in material compliance with existing environmental, health and safety regulations. We believe that the cost of maintaining compliance with these existing regulations will not have a material adverse effect on our business, financial position and results of operation, but new or more stringent regulations could increase the cost of doing business.

Climate Change. Various state governments and regional organizations comprising state governments are considering enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as our equipment and operations. At the federal level, the EPA has already made findings and issued regulations that require us to establish and report an inventory of greenhouse gas emissions and that could lead to the imposition of restrictions on greenhouse gas emissions from stationary sources such as ours. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the natural gas and oil that we sell. The potential increase in our operating costs could include new or increased costs to obtain permits, operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas and oil.

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 incur legal defense costs and 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 $75 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 $400 million comprehensive general liability umbrella policy and a $130 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. In addition, our insurance does not cover penalties or fines that may be assessed by a governmental authority. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. The insurance coverage that we maintain may not be sufficient to cover every claim made against us in the future.

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Facilities

Chesapeake owns an office complex in Oklahoma City and we continue to construct additional buildings in Oklahoma City and in our operating areas as needed to accommodate our ongoing growth. We also own or lease various field or administrative offices in the areas in which we conduct operations.

Employees

Chesapeake had approximately 10,000 employees as of December 31, 2010.

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.

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.

Drilling Carry Obligation. An obligation of one party to pay certain well costs attributable to another party.

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

Exploratory Well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another 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.

Natural Gas Liquids (NGL). Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing or cycling plants. Natural gas liquids primarily include ethane, propane, butane, isobutene, pentane, hexane and natural gasoline.

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.

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 calculated as the average natural gas and oil price during the preceding 12-month period prior to the end of the current reporting period, (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period) 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%.

Price Differential. The difference in the price of natural gas or oil received at the sales point and the New York Mercantile Exchange (NYMEX).

Productive Well. A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

Proved Developed Reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

Proved Properties. Properties with proved reserves.

Proved Reserves. Proved natural gas and oil reserves are those quantities of natural gas and oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of a reservoir considered as proved includes (a) the area indentified by drilling and limited by fluid contacts, if any, and (b) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil on the basis of available geoscience and engineering data. In the absence of information on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (a) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (b) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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

Proved Undeveloped Reserves. Proved 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 shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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.

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 the prices used in estimating the proved reserves, year-end 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.

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

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

Unproved Properties. Properties with no proved reserves.

VPP. As we use the term, a volumetric production payment represents a limited-term overriding royalty interest in natural gas and oil reserves that (i) entitles the purchaser to receive scheduled production volumes over a period of time from specific lease interests; (ii) is free and clear of all associated future production costs and capital expenditures; (iii) is nonrecourse to the seller (i.e., the purchaser s only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain the remaining reserves, if any, after the scheduled production volumes have been delivered.

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 fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse effect on our business.

Our revenues, operating results, profitability and ability to grow depend primarily upon the prices we receive for the natural gas and oil we sell. We require substantial expenditures to replace reserves, sustain production and fund our business plans. Lower natural gas or oil prices can negatively affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. In addition, lower prices may result in ceiling test write-downs of our natural gas and oil properties. We urge you to read the risk factors below for a more detailed description of each of these risks.

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:

- domestic and worldwide supplies of natural gas, oil and natural gas liquids, including U.S. inventories of natural gas and oil reserves;
- weather conditions;
- changes in the level of consumer demand;
- the price and availability of alternative fuels;
- the availability, proximity and capacity of pipelines, other transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;

- the price and level of foreign imports;
- the nature and extent of 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 and natural gas 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. Further, the prices of natural gas and oil do not necessarily move in tandem. Because approximately 90% of our reserves at December 31, 2010 were natural gas reserves, we are more affected by movements in natural gas prices.

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Our level of indebtedness may limit our financial flexibility.

As of December 31, 2010, we had long-term indebtedness of approximately $12.6 billion, and our net indebtedness represented 45% of our total book capitalization, which we define as the sum of total Chesapeake stockholders equity and total current and long-term debt less cash. We had $3.706 billion of outstanding borrowings drawn under our revolving bank credit facilities at December 31, 2010.

Our level of indebtedness 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 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;
- the midstream revolving bank credit facility restricts the payment of dividends or distributions to Chesapeake;
- 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
- a lowering 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 we pay on our corporate revolving bank credit facility.

The borrowing base of our corporate revolving bank credit facility is subject to periodic redetermination and is based in part on natural gas and oil prices. A lowering of our borrowing base because of lower natural gas and oil prices or for other reasons could require us to repay indebtedness in excess of the borrowing base, or we might need to further secure the lenders with additional collateral. We may incur additional debt, including secured indebtedness, in order to develop our properties and make future acquisitions. A higher level of indebtedness 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 and our performance at the time we need capital. In addition, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

Declines in the prices of natural gas and oil could result in a write-down of our asset carrying values.

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 unweighted arithmetic average of the prices on the first day of each month within the 12-month period ending in the quarter, adjusted for the impact of derivatives accounted for as cash flow hedges. We are required to write down the carrying value of our natural gas and oil assets if capitalized costs exceed the ceiling limit, and such write-downs can be material. For example, our financial statements for the year ended December 31, 2009 reflect an impairment of approximately $6.9 billion, net of income tax, of our natural gas and oil properties. The risk that we will be required to write down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are low or volatile. We may experience ceiling test write-downs or other impairments in the future.

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 corporate revolving bank credit facility, debt and equity issuances and asset monetizations. 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

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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 47% of our total estimated proved reserves (by volume) at December 31, 2010 were undeveloped. By their nature, estimates of proved undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates at December 31, 2010 reflected a decline in the production rate on producing properties of approximately 30% in 2011 and 19% in 2012. 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, 2010, approximately 47% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflect our plans to make significant capital expenditures to convert our proved undeveloped reserves into proved developed reserves, including approximately $10.6 billion during the five years ending in 2015. You should be aware that the estimated development costs may not be accurate, development may not occur as scheduled and results may not be as estimated. If we choose not to develop PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC s reserve reporting rules, because PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to write off any PUDs that are not developed within this five-year time frame.

You should not assume that the present values included 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 price on the date of estimate is calculated as the average natural gas and oil price during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. The December 31, 2010 present value is based on $4.38 per mcf of natural gas and $79.42 per barrel of oil before price differential adjustments. 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 the actual future net cash flows from our production.

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

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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.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We acquire significant amounts of unproved property in order to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Drilling for natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for natural gas and crude oil, costs associated with producing natural gas and oil and our ability to add reserves at an acceptable cost. We rely to a significant extent on seismic data and other advanced technologies in identifying unproved property prospects and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of unproved property or drilling a well, whether natural gas or oil is present or may be produced economically. The use of seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies. Drilling results in our newer natural gas and liquids-rich unconventional plays may be more uncertain than in unconventional plays that are more developed and have longer established production histories, and we can provide no assurance that drilling and completion techniques that have proven to be successful in other unconventional formations to maximize recoveries will be ultimately successful when used in new unconventional formations.

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

Leases on natural gas and oil properties typically have a term of three to five years after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. While we seek to actively manage our leasehold inventory using our drilling rig fleet and service operations to drill sufficient wells to hold the leasehold that we believe is material to our operations, our drilling plans for these areas are subject to change based upon various 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 we receive for our natural gas and oil sales, require us to provide collateral for hedging liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.

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 derivatives 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.

Derivative transactions involve the risk that counterparties, which are generally financial institutions, may be unable to satisfy their obligations to us. Although the counterparties to our multi-counterparty secured hedge facility are required to secure their hedging obligations to us under certain scenarios, if any of our counterparties were to default on its obligations to us under the hedging contracts or seek bankruptcy protection, it could have an adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future production being subject to commodity price changes. The risk of counterparty default is heightened in a poor economic environment.

A substantial portion of our natural gas and oil derivative contracts are with the 12 counterparties in our multi-counterparty hedging facility. Our obligations under the facility are secured by natural gas and oil proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times. Under certain circumstances, such as a spike in volatility measures without a corresponding change in commodity prices, the collateral value could fall below the coverage designated, and we would be required to post additional reserve collateral to our hedge facility. If we did not have sufficient unencumbered natural gas and oil properties available to cover the shortfall, we would be required to post cash or letters of credit with the counterparties. Future collateral requirements are dependent to a great extent on natural gas and oil prices.

Natural gas and oil drilling and producing operations can be hazardous and may expose us to liabilities, including 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 natural gas, oil, 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. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells or otherwise negatively impacting the projected economic performance of our prospects. 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 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.

Potential legislative and regulatory actions could increase our costs, reduce our revenue and cash flow from natural gas and oil sales, reduce our liquidity or otherwise alter the way we conduct our business.

The activities of exploration and production companies operating in the United States are subject to extensive regulation at the federal, state and local levels. Changes to existing laws and regulations or new laws and regulations such as those described below could, if adopted, have an adverse effect on our business.

Federal Taxation of Producers of Natural Gas and Oil

Federal budget proposals would potentially increase and accelerate the payment of federal income taxes of producers of natural gas and oil. Proposals that would significantly affect us would repeal the expensing of intangible drilling costs, the percentage depletion allowance and lengthen the amortization period of geological and geophysical expenses. These changes, if enacted, will make it more costly for us to explore for and develop our natural gas and oil resources.

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OTC Derivatives Regulation

In July 2010, the U.S. Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which contains measures aimed at increasing the transparency and stability of the over-the-counter (OTC) derivative markets and preventing excessive speculation. We maintain an active price and basis protection hedging program related to the natural gas and oil we produce to manage the risk of low commodity prices and to predict with greater certainty the cash flow from our hedged production. We have used the OTC market exclusively for our natural gas and oil derivative contracts. The Dodd-Frank Act and the rules and regulations promulgated thereunder could reduce trading positions in the energy futures markets. Such changes could materially reduce our hedging opportunities and negatively affect our revenues and cash flow during periods of low commodity prices.

Hydraulic Fracturing

Hydraulic fracturing is used in completing greater than 90% of all natural gas and oil wells drilled today in the United States. Certain environmental and other groups have suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. We cannot predict whether any such federal, state or local laws or regulations will be enacted and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed through the adoption of new laws and regulations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

Climate Change

Various state governments and regional organizations comprising state governments are considering enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as our equipment and operations. At the federal level, the EPA has already made findings and issued regulations that require us to establish and report an inventory of greenhouse gas emissions and that could lead to the imposition of restrictions on greenhouse gas emissions from stationary sources such as ours. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the natural gas and oil that we sell. The potential increase in our operating costs could include new or increased costs to obtain permits, operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas and oil.

The decline in general economic, business and industry conditions since 2008 and the current economic uncertainty may have a material adverse effect on our results of operations, liquidity and financial condition.

Since 2008, concerns over sovereign debt levels, energy costs, geopolitical issues, the availability and cost of credit, the U.S. mortgage market and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy.

These factors, combined with volatile natural gas and oil prices, the decline in business and consumer confidence and high unemployment, precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates further, demand for petroleum products could continue to diminish and prices for natural gas and oil could decrease, which could adversely impact our results of operations, liquidity and financial condition.

Our cash flow from operations, our revolving bank credit facilities 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. Poor economic conditions may negatively affect:

- our ability to access the capital markets at a time when we would like, or need, to raise capital;

the number of participants in our proposed asset monetization transactions or the values we are able to realize in those transactions, making them uneconomic or harder or impossible to consummate;

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the collectability of our trade receivables and could cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection; or

the ability of our industry participation partners to meet their obligations to fund a portion of our drilling costs under our industry participation agreements.

Our operations may be adversely affected by oilfield services shortages, pipeline and gathering system capacity constraints and various transportation interruptions.

From time to time, we experience delays in drilling and completing our natural gas and oil wells. Because of the large scale of our operations, there may not be available drilling rigs of the type we require in certain areas of our operations. Additionally, there is currently a shortage of hydraulic fracturing capacity, especially in the unconventional U.S. natural gas and oil plays where hydraulic fracturing is necessary for the successful development of wells. In developing plays, the demand for equipment such as pipe and compressors can exceed the supply, and it is challenging to attract and retain qualified oilfield workers. Delays in developing our natural gas and oil assets for these and other reasons could negatively affect our revenues and cash flow.

In certain natural gas shale plays, the capacity of gathering systems and transportation pipelines is insufficient to accommodate potential production from existing and new wells. Capital constraints could limit the construction of new pipelines and gathering systems by third parties, and we may experience delays in building intrastate gathering systems necessary to transport our natural gas to interstate pipelines. Until this new capacity is available, we may experience delays in producing and selling our natural gas. 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

On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the company and certain of its officers and directors along with certain underwriters of the company s July 2008 common stock offering. Following the appointment of a lead plaintiff and counsel, the plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. The defendants motion to dismiss was denied on September 2, 2010. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against the company s directors and certain of its officers alleging breaches of fiduciary duties relating to the disclosure matters alleged in the securities case. The derivative action is stayed pursuant to stipulation.

On March 26, 2009, a shareholder filed a petition in the District Court of Oklahoma County, Oklahoma seeking to compel inspection of company books and records relating to compensation of the company s CEO. On August 20, 2009, the court denied the inspection demand, dismissed the petition and entered judgment in favor of Chesapeake. The shareholder is appealing the court s ruling in the Oklahoma Court of Civil Appeals.

Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7, and May 20, 2009 against the company s directors alleging breaches of fiduciary duties relating to compensation of the company s CEO and alleged insider trading, among other things, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition was filed on June 23, 2009. Chesapeake is named as a nominal defendant. Chesapeake s motion to dismiss was granted on February 28, 2010, and plaintiffs were given leave to amend. Plaintiffs chose not to amend and on April 9, 2010, at plaintiffs request, the court entered an order certifying that the February 28, 2010 dismissal was a final, appealable order. Plaintiffs are appealing the dismissal in the Oklahoma Court of Civil Appeals.

We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the foregoing cases. It is inherently difficult to predict the outcome of any litigation, and these proceedings are at an early stage.

Chesapeake is also involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, several mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The company believes that it has substantial defenses to the claims made in these purchase and sale cases. The company records an associated liability when a loss is probable and the amount is reasonably estimable. Although the outcome of litigation cannot be predicted with certainty, management is of the opinion that no pending or threatened lawsuit or dispute incidental to its business operations is likely to have a material adverse effect on the company s consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management s estimates.

There are pending against us enforcement actions initiated in the 2010 fourth quarter and 2011 first quarter by the Pennsylvania Department of Environmental Protection related to alleged methane migration into the groundwater and residential water wells and by the U.S. Environmental Protection Agency related to our compliance with Clean Water Act permitting requirements in West Virginia. We have responded to all pending orders and are actively cooperating with the relevant agencies. While we cannot predict with certainty whether these actions will result in fines or penalties, if fines or penalties are imposed, we reasonably believe that each of these actions would result in monetary sanctions exceeding $100,000.

ITEM 4. ***Reserved***

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Part II

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

Price Range of Common Stock and Dividends

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 and the amount of cash dividends declared per share:

	Common Stock		Dividend
	High	Low	Declared
Year ended December 31, 2010:			
Fourth Quarter	$ 26.15	$ 21.12	$ 0.075
Third Quarter	$ 22.65	$ 20.04	$ 0.075
Second Quarter	$ 25.36	$ 20.75	$ 0.075
First Quarter	$ 28.97	$ 22.37	$ 0.075
Year ended December 31, 2009:			
Fourth Quarter	$ 30.00	$ 22.06	$ 0.075
Third Quarter	$ 29.49	$ 16.92	$ 0.075
Second Quarter	$ 24.66	$ 16.43	$ 0.075
First Quarter	$ 20.13	$ 13.27	$ 0.075

At February 24, 2011, there were approximately 2,050 holders of record of our common stock and approximately 398,250 beneficial owners.

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 corporate revolving bank credit facility contains a restriction on our ability to declare and pay cash dividends on our common or preferred stock if an event of default has occurred. The certificates of designation for our 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 the preferred stock.

Purchases of Common Stock

The following table presents information about repurchases of our common stock during the three months ended December 31, 2010:

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, 2010 through October 31, 2010	206,562	$ 21.90		
November 1, 2010 through November 30, 2010	8,331	$ 21.37		
December 1, 2010 through December 31, 2010	12,909	$ 25.92		

Total	227,802	$	23.06

(a) Represents the deemed surrender to the company of 4,389 shares of common stock to pay the exercise price and withholding taxes in connection with the exercise of employee stock options and the surrender to the company of 223,413 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 the 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, 2010, 2009, 2008, 2007 and 2006. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. 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,				
	2010	**2009**	**2008**	**2007**	**2006**
STATEMENT OF OPERATIONS DATA:	($ in millions, except per share data)				
REVENUES:					
Natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858	$ 5,624	$ 5,619
Marketing, gathering and compression sales	3,479	2,463	3,598	2,040	1,577
Service operations revenue	240	190	173	136	130
Total revenues	9,366	7,702	11,629	7,800	7,326
OPERATING COSTS:					
Production expenses	893	876	889	640	490
Production taxes	157	107	284	216	176
General and administrative expenses	453	349	377	243	139
Marketing, gathering and compression expenses	3,352	2,316	3,505	1,969	1,522
Service operations expense	208	182	143	94	68
Natural gas and oil depreciation, depletion and amortization	1,394	1,371	1,970	1,835	1,359
Depreciation and amortization of other assets	220	244	174	153	103
Impairment of natural gas and oil properties		11,000	2,800		
(Gains) losses on sales of other property and equipment	(137)	38			
Other impairments	21	130	30		
Restructuring costs		34			
Employee retirement expense					55
Total Operating Costs	6,561	16,647	10,172	5,150	3,912
INCOME (LOSS) FROM OPERATIONS	2,805	(8,945)	1,457	2,650	3,414
OTHER INCOME (EXPENSE):					
Interest expense	(19)	(113)	(271)	(401)	(316)
Earnings (losses) from equity investees	227	(39)	(38)		10
Losses on redemptions or exchanges of debt	(129)	(40)	(4)		
Impairment of investments	(16)	(162)	(180)		
Gain on sale of investments				83	117
Other income	16	11	27	15	16
Total Other Income (Expense)	79	(343)	(466)	(303)	(173)
INCOME (LOSS) BEFORE INCOME TAXES	2,884	(9,288)	991	2,347	3,241
INCOME TAX EXPENSE (BENEFIT):					
Current income taxes		4	423	29	5
Deferred income taxes	1,110	(3,487)	(36)	863	1,242
Total Income Tax Expense (Benefit)	1,110	(3,483)	387	892	1,247

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	Years Ended December 31,				
	2010	2009	2008	2007	2006
STATEMENT OF OPERATIONS DATA (continued):	($ in millions, except per share data)				
NET INCOME (LOSS)	1,774	(5,805)	604	1,455	1,994
Net (income) loss attributable to noncontrolling interest		(25)			
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,774	(5,830)	604	1,455	1,994
Preferred stock dividends	(111)	(23)	(33)	(94)	(89)
Loss on conversion/exchange of preferred stock			(67)	(128)	(10)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 1,663	$ (5,853)	$ 504	$ 1,233	$ 1,895
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ 2.63	$ (9.57)	$ 0.94	$ 2.70	$ 4.76
Assuming dilution	$ 2.51	$ (9.57)	$ 0.93	$ 2.63	$ 4.33
CASH DIVIDENDS DECLARED PER COMMON SHARE	$ 0.30	$ 0.30	$ 0.2925	$ 0.2625	$ 0.23
CASH FLOW DATA:					
Cash provided by operating activities	$ 5,117	$ 4,356	$ 5,357	$ 4,974	$ 4,843
Cash used in investing activities	$ 8,503	$ 5,462	$ 9,965	$ 7,964	$ 8,942
Cash provided by (used in) financing activities	$ 3,181	$ (336)	$ 6,356	$ 2,988	$ 4,042
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 37,179	$ 29,914	$ 38,593	$ 30,764	$ 24,413
Long-term debt, net of current maturities	$ 12,640	$ 12,295	$ 13,175	$ 10,178	$ 7,187
Total equity	$ 15,264	$ 12,341	$ 17,017	$ 12,624	$ 11,366

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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,		
	2010	**2009**	**2008**
Net Production:			
Natural gas (bcf)	924.9	834.8	775.4
Oil (mmbbl)[(a)]	18.4	11.8	11.2
Natural gas equivalent (bcfe)	1,035.2	905.5	842.7
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 3,169	$ 2,635	$ 6,003
Natural gas derivatives realized gains (losses)	1,982	2,313	267
Natural gas derivatives unrealized gains (losses)	425	(492)	521
Total natural gas sales	5,576	4,456	6,791
Oil sales[(a)]	1,079	656	1,066
Oil derivatives realized gains (losses)	74	33	(275)
Oil derivatives unrealized gains (losses)	(1,082)	(96)	276
Total oil sales	71	593	1,067
Total natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 3.43	$ 3.16	$ 7.74
Oil ($ per bbl)	$ 58.67	$ 55.60	$ 95.04
Natural gas equivalent ($ per mcfe)	$ 4.10	$ 3.63	$ 8.39
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 5.57	$ 5.93	$ 8.09
Oil ($ per bbl)	$ 62.71	$ 58.38	$ 70.48
Natural gas equivalent ($ per mcfe)	$ 6.09	$ 6.22	$ 8.38
Other Operating Income[(b)] ($ in millions):			
Marketing, gathering and compression net margin	$ 127	$ 147	$ 93
Service operations net margin	$ 32	$ 8	$ 30
Other Operating Income[(b)] ($ per mcfe):			
Marketing, gathering and compression net margin	$ 0.12	$ 0.16	$ 0.11
Service operations net margin	$ 0.03	$ 0.01	$ 0.04
Expenses ($ per mcfe):			
Production expenses	$ 0.86	$ 0.97	$ 1.05
Production taxes	$ 0.15	$ 0.12	$ 0.34
General and administrative expenses	$ 0.44	$ 0.38	$ 0.45
Natural gas and oil depreciation, depletion and amortization	$ 1.35	$ 1.51	$ 2.34
Depreciation and amortization of other assets	$ 0.21	$ 0.27	$ 0.21
Interest expense[(c)]	$ 0.08	$ 0.22	$ 0.22
Interest Expense ($ in millions):			
Interest expense[(c)]	$ 99	$ 227	$ 192
Interest rate derivatives realized (gains) losses	(14)	(23)	(6)

Interest rate derivatives unrealized (gains) losses	(66)	(91)	85
Total interest expense	$ 19	$ 113	$ 271
Net Wells Drilled	1,149	1,003	1,733
Net Producing Wells as of the End of Period	22,617	22,919	22,813

(a) Includes NGLs.

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

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

We manage our business as three separate operational segments: exploration and production; marketing, gathering and compression; and service operations, which is comprised of our wholly owned drilling and trucking operations. We refer you to Note 16 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 2010, 2009 and 2008 and our assets as of December 31, 2010, 2009 and 2008.

Executive Summary

We are the second-largest producer of natural gas and a top 20 producer of oil and natural gas liquids in the U.S. We own interests in approximately 46,000 producing natural gas and oil wells that are currently producing approximately 3.0 bcfe per day, 87% of which is natural gas. Our strategy is focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S., primarily in the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville and Bossier Shales in 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 and Pennsylvania. We also have substantial operations in the liquids-rich plays of the Eagle Ford Shale in South Texas, the Granite Wash, Cleveland, Tonkawa and Mississippian plays in the Anadarko Basin in western Oklahoma and the Texas Panhandle, the Niobrara Shale, Frontier and Codell plays in the Powder River and DJ Basins of Wyoming and Colorado and the Avalon, Bone Spring, Wolfcamp and Wolfberry plays in the Permian and Delaware Basins of West Texas and southern New Mexico, as well as various other plays, both conventional and unconventional, in the Mid-Continent, Williston Basin, Appalachian Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the U.S. We have also vertically integrated our operations and own substantial midstream, compression, drilling and oilfield service assets. As described below, we have agreed to sell our Fayetteville Shale assets in a transaction expected to close in the first half of 2011.

Chesapeake began 2010 with estimated proved reserves of 14.254 tcfe and ended the year with 17.096 tcfe, an increase of 2.842 tcfe, or 20%. During 2010, we replaced 1.035 tcfe of production with an estimated 3.877 tcfe of new proved reserves, for a reserve replacement rate of 375%. The 2010 proved reserve movement included 5.098 tcfe of extensions, 0.006 tcfe of downward performance revisions and 0.189 tcfe of positive revisions resulting from an increase in the twelve-month trailing average natural gas and oil prices between December 31, 2009 and December 31, 2010. During 2010, we acquired 0.089 tcfe of estimated proved reserves and divested 1.493 tcfe of estimated proved reserves.

Chesapeake continued the industry s most active drilling program in 2010 and drilled 1,445 gross (938 net) operated wells and participated in another 1,586 gross (211 net) wells operated by other companies. The company s drilling success rate was 98% for both company-operated and non-operated wells. Also during 2010, we invested $4.6 billion in operated wells (using an average of 131 operated rigs) and $815 million in non-operated wells (using an average of 123 non-operated rigs) for total drilling and completion costs of $5.4 billion, net of drilling and completion cost carries of $1.2 billion.

Our average daily production for 2010 of 2.836 bcfe consisted of 2.534 bcf (89% on a natural gas equivalent basis) and 50,397 bbls (11% on a natural gas equivalent basis) and was an increase of 355 mmcfe, or 14%, over the 2.481 bcfe of daily production for 2009. Total production for 2010 was 1,035 tcfe, an increase of 129.7 bcfe, or 14%, over 2009 total production of 905.5 bcfe. This was our 21st consecutive year of sequential production growth.

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (13.3 million net acres) and 3-D seismic (27.9 million acres) in the U.S. This position includes the largest inventory of U.S. natural gas shale play leasehold (2.5 million net acres) as well as the largest combined leasehold position in two of the three largest new unconventional liquids-rich plays in the U.S. the Eagle Ford Shale and the Niobrara Shale. We are currently using 157 operated rigs to further develop our inventory of approximately 37,800 net drillsites.

Implementing Our Strategy

In recognition of the value gap between oil and natural gas prices, during the past two years Chesapeake has directed a significant portion of its technological, geo-scientific, leasehold acquisition and drilling expertise to identifying, securing and commercializing new unconventional liquids-rich plays. This planned transition will result in a more balanced portfolio between natural gas and liquids. To date, we have built leasehold positions and established production in multiple unconventional liquids-rich plays on approximately 4.1 million net leasehold acres. In 2010, we invested approximately $4.7 billion, net of divestitures, primarily in liquids-rich acreage, and we allocated approximately 30% of our $5.4 billion drilling and completion capital expenditures to these plays, compared to 10% in 2009. Our production of oil and natural gas liquids was 50,397 bbls per day during 2010, a 56% increase over the average for 2009 as a result of the increased development of our unconventional liquids-rich plays. We are projecting that the portion of drilling and completion capital expenditures allocated to liquids development will reach 50% in 2011 and 75% in 2012, and we expect to increase our oil and natural gas liquids production through our drilling activities to more than 150,000 bbls per day, or 20%-25% of total production, by year-end 2012.

This shift to a greater emphasis on liquids production is a continuation of our general business strategy outlined in Item 1. *Business*. Our goal is to create value for investors by focusing on developing unconventional resource plays onshore in the U.S. We do so by:

- Growing through the drillbit We are the most active driller in the U.S., have our own fleet of 105 drilling rigs and are currently using 157 operated rigs. Our integrated marketing, gathering, compression and trucking services operations support our drilling activities so that we are able to manage the development of our leasehold efficiently and strategically.

- Controlling substantial land and drilling location inventories and building regional scale We have been first movers in capturing both natural gas and liquids-rich unconventional leasehold and resources. During 2010, we invested heavily in a large number of highly competitive liquids-rich unconventional plays in order to accelerate our transition to increased liquids production. We now have achieved many of our leasehold acquisition goals and are becoming a significant seller of leasehold through new industry participation agreements and the pending sale of our Fayetteville Shale assets.

- Developing proprietary technological advantages We support the scale of our operations with what we believe is the nation s largest inventory of 3-D seismic information and our state-of-the-art Reservoir Technology Center, or RTC. The RTC provides us a substantial competitive advantage, enabling us among other things to more quickly, accurately and confidentially analyze core data from wells drilled through unconventional formations on a proprietary basis and then identify new plays and leasing opportunities ahead of our competition and reduce the likelihood of investing in plays that ultimately are not commercial. Our 3-D seismic data permits us to image reservoirs of natural gas and oil that might otherwise remain undiscovered and to drill our horizontal wells more accurately inside the targeted formation.

- Focusing on low costs We minimize lease operating costs and general and administrative expenses through focused activities, vertical integration and increasing scale. As of December 31, 2010, our operated wells accounted for approximately 80% of our daily production volume, providing us with a high degree of operational flexibility and cost control.

- Mitigating natural gas and oil price risk We actively seek to manage our exposure to adverse market prices for natural gas and oil through our hedging program. Hedging allows us to predict with greater certainty the effective prices we will receive for our hedged natural gas and oil production. Our realized cash hedging gains for 2010 were $2.056 billion and since January 1, 2001 have been $6.478 billion.

- Using industry participation agreements Through industry participation property sales, we have recouped substantially all of our lease acquisition costs in six of our significant unconventional operating areas, and we hold leasehold in new plays which we believe will be best developed through future industry participation agreements. In addition, drilling cost carries allow us to accelerate the development of new plays at a reduced cost to us. We pioneered the industry participation model of unconventional natural gas and oil development, and many other E&P companies have followed with their own industry participation agreements in the past two years.

Our strategic and financial plan for 2011-2012, announced on January 6, 2011 as our 25/25 Plan , calls for a 25% reduction in our outstanding long-term debt while growing net natural gas and oil production by 25% by the end of 2012. We expect to achieve the reduction in debt through asset monetizations. Among the several benefits of lower debt are lower borrowing costs, and we believe improved credit metrics will lead to a more favorable debt rating by the major ratings agencies.

Our goal of a 25% reduction in debt by year-end 2012 is part of our liability management plan begun in 2010. During 2010, we issued in private placements 2.6 million shares of two series of our 5.75% Cumulative Non-Voting Convertible Preferred Stock resulting in net proceeds to us of approximately $2.562 billion. We used the net proceeds of these preferred stock offerings to redeem in whole $1.934 billion in principal amount of four series of our outstanding senior notes. Additionally, through tender offers followed by redemptions, we purchased $1.5 billion aggregate principal amount of three additional series of senior notes. We funded the purchase of the notes tendered and redeemed with proceeds from a $2.0 billion public offering of two series of senior notes. We retired all series of our outstanding senior notes that were issued under our more restrictive indentures. Excess funds from our offerings were used to repay borrowings outstanding under our corporate revolving bank credit facility.

During 2011, we plan to take steps to extend the maturity profile of our outstanding indebtedness at advantageous rates. On February 11, 2011, the company issued $1.0 billion principal amount of 6.125% Senior Notes due 2021 in a registered public offering. We applied the net proceeds of $977 million from the offering to our revolving bank credit facility balance and plan to use proceeds from asset sales to retire at least $2.0 - $3.0 billion of our shorter-dated senior notes and also to reduce borrowings under our revolving bank credit facility.

Asset monetizations were also key elements of our strategic and financial plan in 2010 and early 2011, as described below.

Industry Participation Agreements

In 2010, Chesapeake completed its fourth and fifth significant industry participation agreements in unconventional natural gas and oil plays. In January 2010, Total E&P USA, Inc., a wholly owned subsidiary of Total S.A. (Total), purchased a 25% undivided interest in 270,000 net acres of our Barnett Shale leasehold, along with 840 bcfe of estimated proved reserves, for approximately $800 million in cash (plus $78 million of drilling and completion carries due from the effective date of the transaction to the closing date). Total agreed to fund 60% of our share of future drilling and completion expenditures in the Barnett Shale until it has paid a total of $1.45 billion in drilling and completion carries, which we expect to occur by year-end 2013. In November 2010, a wholly owned subsidiary of CNOOC Limited (CNOOC) purchased a 33.3% undivided interest in 600,000 net acres of our Eagle Ford Shale leasehold, along with 18.2 bcfe of estimated proved reserves, for approximately $1.12 billion in cash. In addition, CNOOC agreed to fund 75% of our share of drilling and completion costs in the Eagle Ford Shale until an additional $1.08 billion has been paid, which we expect to occur by year-end 2012. All proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized. Both Total and CNOOC have the right to participate proportionately with us in any additional leasehold we acquire in the Barnett Shale and the Eagle Ford Shale, respectively, at cost plus a fee.

The following table provides information about our remaining industry participation agreement drilling and completion carries as of December 31, 2010:

Shale Play	**Industry Participation Agreement Partner**	**Date**	**Carries Remaining ($ in millions)**
Marcellus	Statoil	November 2008	$ 1,362
Barnett	Total	January 2010	889
Eagle Ford	CNOOC	November 2010	1,030
			$ 3,281

On February 16, 2011, we entered into an industry participation agreement with a wholly owned U.S. subsidiary of CNOOC Limited (CNOOC) to develop our Niobrara Shale play in the DJ and Powder River Basins in northeast Colorado and southeast Wyoming. Under the terms of the industry participation agreement, CNOOC acquired a 33.3% undivided interest in approximately 800,000 net acres of our leasehold. We received $570 million in cash at closing, and CNOOC has agreed to fund 66.7% of our share of drilling and completion costs until an additional $697 million has been paid, which we expect to occur by year-end 2014. In addition, CNOOC has the right to a 33.3% participation in any additional leasehold we acquire in the area at cost plus a fee.

The drilling and completion carries in our industry participation agreements create a significant cost advantage that allows us to continue to lower finding costs. During 2010 and 2009, our drilling and completion costs included the benefit of approximately $1.151 billion and $1.154 billion, respectively, of drilling and completion carries. Our drilling and completion costs for 2011 through 2014 will continue to be partially offset by the use of our remaining drilling and completion carries associated with our industry participation agreements.

Volumetric Production Payments

We completed three volumetric production payments (VPPs) in 2010, bringing the total of such transactions to eight. The company s sixth VPP was completed in February 2010 for proceeds of approximately $180 million, or $3.95 per mcfe. In June 2010, we completed our seventh VPP for proceeds of approximately $335 million, or $8.73 per mcfe.

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In September 2010, we completed our eighth VPP for proceeds of approximately $1.15 billion, or $2.93 per mcfe. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Other Asset Sales

In 2010, we sold non-core proved and unproved properties for proceeds of approximately $355 million. During 2010, as part of our industry participation agreements with Total, Statoil and PXP, we sold interests in additional leasehold in the Barnett, Marcellus and Haynesville Shale plays for proceeds of approximately $440 million that had an estimated original cost to us of $220 million. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Chesapeake Midstream Partners, L.P. IPO and Asset Sale

On August 3, 2010, Chesapeake Midstream Partners, L.P. (NYSE: CHKM), which we and GIP formed to own, operate, develop and acquire midstream assets, completed an initial public offering of common units representing limited partner interests and received net proceeds of approximately $475 million. In connection with the closing of the offering and pursuant to the terms of our contribution agreement with GIP, CHKM distributed to GIP the approximate $62 million of net proceeds from the exercise of the offering over-allotment option, and Chesapeake and GIP contributed the interests of their midstream joint venture operating subsidiary to CHKM. Chesapeake and GIP hold 42.3% and 40.0%, respectively, of all outstanding limited partner interests, and Chesapeake and GIP each have a 50% interest in the general partner of CHKM. CHKM makes quarterly distributions to its partners, and at the current annual rate of $1.35 per unit, Chesapeake receives quarterly distributions of approximately $20 million in respect of its limited partner and general partner interests. In 2010, we received cash distributions of $88 million from CHKM and its predecessor joint venture.

We account for our investment in CHKM under the equity method. During 2010, we recorded positive equity method adjustments of $89 million for our share of CHKM s income and recorded accretion adjustments of $14 million for our share of equity in excess of cost. As a result of CHKM s initial public offering, we recognized a $90 million gain on our investment, which represented our proportionate share of the excess of offering proceeds over the carrying value of our investment in CHKM and is reported in earnings (losses) from equity investees on our consolidated statements of operations.

On December 21, 2010, we sold our Springridge natural gas gathering system and related facilities in the Haynesville Shale to CHKM for $500 million and entered into ten-year gathering and compression agreements with CHKM. Additional information on the transaction is included in Item 1 under *Marketing, Gathering and Compression - Midstream Gathering Operations.*

Pending and Planned Asset Sales

Fayetteville Shale. On February 21, 2011, we entered into a purchase and sale agreement with a wholly owned subsidiary of BHP Billiton to sell all of our Fayetteville Shale assets, including approximately 487,000 net acres of leasehold and producing natural gas properties and midstream assets with approximately 420 miles of pipeline, for $4.75 billion in cash before certain deductions and standard closing adjustments. In the Fayetteville Shale, our current net production is approximately 415 mmcfe per day. Estimated proved reserves attributable to the Fayetteville Shale as of December 31, 2010 were 2.4 tcfe, or approximately 14% of our total proved reserves. As part of the transaction, we have agreed to provide essential services for up to one year for BHP Billiton s Fayetteville Shale properties for an agreed-upon fee. Closing of the transaction is subject to customary conditions, including filings under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and with the Committee on Foreign Investment in the United States. Closing is expected to occur in the first half of 2011.

Frac Tech Holdings, LLC and Chaparral Energy, Inc. Asset Sales. We plan to sell our 25.8% equity interest in Frac Tech Holdings, LLC and our 20% equity interest in Chaparral Energy, Inc. Each of the foregoing proposed transactions is subject to changes in market conditions and other factors, and there can be no assurance that we will complete any or all of these transactions on a timely basis or at all.

Other. During 2011, the company expects to enter into additional asset monetizations, including industry participation agreements in liquids-rich plays, new VPPs, certain midstream assets sales and various other smaller planned sales.

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Capital Expenditures

Our exploration, development and acquisition activities require us to make substantial capital expenditures. Our current budgeted drilling and completion capital expenditures, net of drilling and completion carries, are $5.0 - $5.4 billion in 2011 and $5.4 - $5.8 billion in 2012. We anticipate funding all or substantially all budgeted drilling and completion capital expenditures using cash flow from operations in 2011 and 2012. We plan to fund our leasehold acquisition capital expenditures, together with other capital expenditure requirements, with a combination of revolving bank credit facility borrowings and proceeds from asset monetizations. As of December 31, 2010, we had made commitments to acquire additional proved and unproved properties in various transactions during the next twelve months for approximately $350 million.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity we use to fund capital expenditures, pay dividends and repay debt. Cash provided by operating activities was $5.117 billion in 2010, compared to $4.356 billion in 2009 and $5.357 billion in 2008. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items such as impairments of assets, depreciation, depletion and amortization, deferred income taxes and changes in our derivative instruments. 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 and oil prices and to provide more predictable future cash flow from operations, we have entered into various derivative instruments. Assuming future NYMEX natural gas settlement prices average $4.50 per mcf for 2011 and including the effect of the company s open derivatives as of February 22, 2011, closed contracts and previously collected call premiums, the company estimates its average natural gas price will be $5.98 per mcf for 2011. This estimate does not include the effect of basis differentials and gathering costs. Our natural gas and oil derivatives as of December 31, 2010 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.

Our $4.0 billion corporate revolving bank credit facility, our $300 million midstream revolving bank credit facility and cash and cash equivalents are other sources of liquidity. We use the credit facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $15.117 billion and repaid $13.303 billion in 2010, we borrowed $7.761 billion and repaid $9.758 billion in 2009, and we borrowed $13.291 billion and repaid $11.307 billion in 2008 from our revolving bank credit facilities. Our corporate facility is secured by natural gas and oil proved reserves. A significant portion of our natural gas and oil reserves are currently unencumbered and therefore available to be pledged as additional collateral if needed to respond to borrowing base and collateral redeterminations our lenders might make in the future. Accordingly, we believe our borrowing capacity under this facility will not be reduced as a result of any such future redeterminations. Our midstream facility is secured by substantially all of our wholly owned midstream assets and is not subject to periodic borrowing base redeterminations. Our revolving bank credit facilities are described below under *Bank Credit Facilities*.

The following table reflects the proceeds from sales of securities we issued in 2010, 2009 and 2008 ($ in millions):

	2010		2009		2008	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Convertible preferred stock	$ 2,600	$ 2,562	$	$	$	$
Senior notes	2,000	1,967	1,425	1,346	800	787
Contingent convertible senior notes					1,380	1,349
Common stock					2,698	2,598
Total	$ 4,600	$ 4,529	$ 1,425	$ 1,346	$ 4,878	$ 4,734

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The following table reflects proceeds we received from our significant natural gas and oil asset monetizations in 2010, 2009 and 2008 ($ in millions):

	2010	2009	2008
Natural gas and oil property monetizations:			
CNOOC (Eagle Ford) industry participation agreement[(a)]	$ 1,170	$	$
TOT (Barnett) industry participation agreement[(b)]	1,361		
STO (Marcellus) industry participation agreement[(c)]	601	162	1,250
PXP (Haynesville) industry participation agreement[(d)]		1,490	1,722
BP (Fayetteville) industry participation agreement[(e)]		601	1,299
BP (Mid-Continent) divestiture			1,688
Volumetric production payments	1,622	408	1,579
Other divestitures	750	418	403
Total	$ 5,504	$ 3,079	$ 7,941

(a) 2010 included $50 million of drilling carries. As of December 31, 2010, $1.030 billion of drilling carry obligations remained outstanding.

(b) 2010 included $561 million of drilling carries. As of December 31, 2010, $889 million of drilling carry obligations remained outstanding.

(c) 2010 and 2009 proceeds were in the form of drilling carries. As of December 31, 2010, $1.362 billion of drilling carry obligations remained outstanding.

(d) 2009 and 2008 included $390 million and $72 million of drilling carries, respectively. 2009 also included a $1.1 billion acceleration of future drilling carries.

(e) 2009 and 2008 included $601 million and $199 million of drilling carries, respectively.

In December 2010, our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., sold its Springridge natural gas gathering system and related facilities in the Haynesville Shale to CHKM for $500 million.

In September 2009, we received $588 million from the sale of a noncontrolling interest in our midstream joint venture agreement with GIP.

In June 2009, we received net proceeds of $54 million from the mortgage financing of our regional Barnett Shale headquarters building in Fort Worth, Texas. The interest-only loan has a five-year term at a floating rate of prime plus 275 basis points. At our option, we may prepay the loan in full without penalty beginning in year four.

In April 2009, we financed 113 real estate surface assets in the Barnett Shale area in and around Fort Worth, Texas for net proceeds of approximately $145 million and entered into a master lease agreement under which we agreed to lease the assets for 40 years for approximately $15 million to $27 million annually. This lease transaction was recorded as a financing lease.

In 2010, 2009 and 2008, we received $621 million and $109 million, and paid $167 million, respectively, for settlements of derivatives which were classified as cash flows from financing activities.

In 2010, we received cash distributions of $88 million from CHKM and its predecessor. In addition, we received cash distributions of $58 million from our equity investee, Frac Tech Holdings, LLC. These cash distributions were accounted for as a return on investment and reflected as cash flows from operating activities.

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 our other investing activities for 2010, 2009 and 2008. 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, changes in 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.

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On June 21, 2010, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in principal amount of our 6.875% Senior Notes due 2016. Associated with these redemptions, we recognized a loss of $69 million in 2010.

On July 22, 2010, we redeemed in whole for a redemption price of approximately $619 million, plus accrued interest, $600 million in principal amount of our 6.375% Senior Notes due 2015. Associated with the redemption, we recognized a loss of $19 million in 2010.

On August 30, 2010, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. On September 16, 2010, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with the August 2010 tender offers and redemptions, we recognized a loss of $40 million in 2010.

We paid dividends on our common stock of $189 million, $181 million and $148 million in 2010, 2009 and 2008, respectively. The Board of Directors increased the quarterly dividend of common stock from $0.0675 to $0.075 per share beginning with the dividend paid in July 2008. We paid dividends on our preferred stock of $92 million, $23 million and $35 million in 2010, 2009 and 2008, respectively. The increase in 2010 was due to the issuance of 2.6 million shares of preferred stock and the decrease from 2008 to 2009 was a result of conversions and exchanges of preferred stock into common stock during 2008 and 2009.

Credit Risk

Derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility 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 we attempt to limit our exposure to non-performance by any single counterparty. During the more than 15 years we have engaged in hedging activities, we have experienced a counterparty default only once (Lehman Brothers in September 2008), and the total loss recorded in that instance was immaterial. On December 31, 2010, our commodity and interest rate derivative instruments were spread among 14 counterparties. Our multi-counterparty secured hedging facility includes 12 of our counterparties which are required to secure their natural gas and oil hedging obligations in excess of defined thresholds. We use this facility for all of our commodity hedging.

Our accounts receivable are primarily from purchasers of natural gas and oil ($821 million at December 31, 2010) and exploration and production companies which own interests in properties we operate ($977 million at December 31, 2010). 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 parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During 2010 and 2008, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables. During 2009, we recognized $13 million of bad debt expense related to potentially uncollectible receivables.

Investing Activities

Cash used in investing activities was $8.503 billion in 2010, compared to $5.462 billion in 2009 and $9.965 billion in 2008. The majority of the increase in investing activities in 2010 was the result of our increased acquisition of unproved properties, primarily in liquids-rich areas, and exploration and development activities. Our investing activities in 2008 reflected our increasing focus on acquiring unproved properties in developing natural gas shale plays, 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. Investing activities in 2009 were at a reduced rate in response to a low natural gas price environment, lower demand and the benefit of our drilling cost carries. Natural gas and oil investing activities increased in 2010 as we pursued our strategy to acquire and develop liquids-rich properties. In each of 2010, 2009 and 2008, we also invested in drilling rigs, gathering systems, compressors, and other property and equipment to support our natural gas and oil exploration, development and

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production activities. The following table details our cash used in (provided by) investing activities during 2010, 2009 and 2008 ($ in millions):

	2010	2009	2008
Natural Gas and Oil Investing Activities:			
Acquisitions of natural gas and oil proved properties	$ 243	$ 5	$ 372
Acquisition of natural gas and oil unproved properties	6,015	1,666	7,660
Exploration and development of natural gas and oil properties	5,061	3,410	5,789
Geological and geophysical costs[a]	181	162	315
Interest capitalized on unproved properties	687	598	561
Deposits for acquisitions of proved and unproved properties	43		12
Proceeds from divestitures of proved and unproved properties	(4,292)	(1,926)	(7,670)
Total natural gas and oil investing activities	7,938	3,915	7,039
Other Investing Activities:			
Additions to other property and equipment	1,326	1,683	3,073
Additions to investments	134	40	74
Proceeds from sales of other assets	(883)	(176)	(219)
Other	(12)		(2)
Total other investing activities	565	1,547	2,926
Total cash used in investing activities	$ 8,503	$ 5,462	$ 9,965

(a) Including related capitalized interest.

Bank Credit Facilities

We utilize two revolving bank credit facilities, described below, as sources of liquidity.

	Corporate Credit Facility[a]	Midstream Credit Facility[b]
	($ in millions)	
Borrowing capacity	$ 4,000	$ 300
Maturity date	December 2015	July 2015
Facility structure	Senior secured revolving	Senior secured revolving
Amount outstanding as of December 31, 2010	$ 3,612	$ 94
Letters of credit outstanding as of December 31, 2010	$ 13	$

(a) Borrower is Chesapeake Exploration, L.L.C.

(b) Borrower is Chesapeake Midstream Operating, L.L.C., a wholly owned subsidiary of Chesapeake Midstream Development, L.P.

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither of our credit facilities contains 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.

Corporate Credit Facility. Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by natural gas and oil proved reserves and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A., or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.50% to 1.25% per annum according to our senior unsecured long-term debt ratings, or (ii) the Eurodollar rate, which is based on the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% 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 of 0.50% 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 and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at December 31, 2010. 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 $50 million or more, 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 Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and certain of our wholly owned subsidiaries.

Midstream Credit Facility. Our $300 million midstream syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems for our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the midstream credit facility are secured by all of the assets of the wholly owned subsidiaries (the restricted subsidiaries) of Chesapeake Midstream Development, L.P. (CMD), itself a wholly owned subsidiary of Chesapeake, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 1.75% to 2.25% per annum according to the most recent leverage ratio described below or (ii) the Eurodollar rate, which is based on the LIBOR plus a margin that varies from 2.75% to 3.25% per annum according to the most recent leverage ratio. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMD and its restricted subsidiaries to incur additional indebtedness, make investments or loans and create liens. The agreement requires maintenance of a leverage ratio based on the ratio of indebtedness to EBITDA and an interest coverage ratio based on the ratio of EBITDA to interest expense, in each case as defined in the agreement. The leverage ratio increases during any three-quarter period, beginning in the quarter in which CMD makes a material disposition of assets to our master limited partnership midstream affiliate, Chesapeake Midstream Partners, L.P. As of December 21, 2010, the leverage ratio increased for a three-fiscal-quarter period beginning October 1, 2010 due to the sale of the Springridge gathering system as it was classified as a material disposition of assets. We were in compliance with all covenants under the agreement at December 31, 2010. If CMD or its restricted 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 facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness of CMD and its restricted subsidiaries may have with an outstanding principal amount in excess of $15 million.

Hedging Facility

We have a multi-counterparty hedge facility with 12 counterparties that have committed to provide approximately 5.6 tcfe of hedging capacity and an aggregate mark-to-market capacity of $15.0 billion under the terms of the facility. In February 2011, we amended the agreement for the hedge facility primarily to allow us to protect our natural gas liquids production from price volatility and to allow for greater flexibility when hedging our anticipated production. As of December 31, 2010, we had hedged a total of 2.9 tcfe of our future production under the facility. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and natural gas liquids price and basis derivatives with the counterparties. Our obligations under the multi-counterparty facility are secured by proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times, and guarantees by our subsidiaries that also guarantee our corporate revolving bank credit facility and indentures. The counterparties obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based hedging capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based hedging limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease entering into hedges with the company on a prospective basis as long as obligations associated with any existing transactions in the facility continue to be satisfied in accordance with the terms of the agreement.

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Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities discussed above, as of December 31, 2010, senior notes represented approximately $8.9 billion of our total debt and consisted of the following ($ in millions):

7.625% senior notes due 2013	$	500
9.5% senior notes due 2015		1,425
6.25% euro-denominated senior notes due 2017[(a)]		796
6.5% senior notes due 2017		1,100
6.875% senior notes due 2018		600
7.25% senior notes due 2018		800
6.625% senior notes due 2020		1,400
6.875% senior notes due 2020		500
2.75% contingent convertible senior notes due 2035[(b)]		451
2.5% contingent convertible senior notes due 2037[(b)]		1,378
2.25% contingent convertible senior notes due 2038[(b)]		752
Discount on senior notes[(c)]		(777)
Interest rate derivatives[(d)]		9
	$	8,934

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3269 to 1.00 as of December 31, 2010. See Note 9 of our consolidated financial statements included in Item 8 of this report for information on our related foreign currency derivatives.

(b) 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 2010, 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 2011 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	$	48.62	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$	64.26	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$	107.36	June 14, 2019

(c) Included in this discount is $711 million at December 31, 2010 associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(d) See Note 9 of our consolidated financial statements included in Item 8 of this report for discussion related to these instruments.

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. Our senior note obligations are guaranteed by certain of our wholly owned subsidiaries, excluding CMD and its subsidiaries. See Note 17 of the consolidated financial statements included in Item 8 of this report for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries. We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole or redemption prices. Our senior notes are governed by indentures containing covenants that may limit our ability and our subsidiaries ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets.

Conversions and Exchanges of Contingent Convertible Senior Notes and Preferred Stock

In 2010, 2009 and 2008, holders of certain of our contingent convertible senior notes exchanged their notes for shares of common stock in privately negotiated exchanges as summarized below:

Year	Contingent Convertible Senior Notes	Principal Amount ($ in millions)	Number of Common Shares (in thousands)
2010	2.25% due 2038	$ 11	299
2009	2.25% due 2038	$ 364	10,210
2008	2.75% due 2035	$ 239	8,841
	2.50% due 2037	272	8,417
	2.25% due 2038	254	6,655
		$ 765	23,913

In 2010, 2009 and 2008, 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 (in thousands)	Number of Common Shares (in thousands)	Type of Transaction
2010	5.0% (series 2005)	5	21	Conversion
2009	6.25%	144	1,239	Conversion
	4.125%	3	183	Conversion
			1,422	
2008	5.0% (series 2005B)	3,654	10,443	Exchange
	4.5%	891	2,228	Exchange
	4.125%	[a]	2	Conversion
			12,673	

(a) Nominal amount.

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Contractual Obligations

The table below summarizes our cash contractual obligations as of December 31, 2010 ($ 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	$ 13,408	$	$ 500	$ 5,131	$ 7,777
Interest	5,193	595	1,173	996	2,429
Financing lease obligations and other	894	18	37	90	749
Operating lease obligations	916	170	345	287	114
Asset retirement obligations[(a)]	301		61	7	233
Purchase obligations[(b)]	5,054	930	874	797	2,453
Unrecognized tax benefits[(c)]	34	34			
Standby letters of credit	13	13			
Total contractual cash obligations	$ 25,813	$ 1,760	$ 2,990	$ 7,308	$ 13,755

(a) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2010 balance sheet.

(b) See Note 4 of the notes to our consolidated financial statements in Item 8 of this report for a description of transportation and drilling contract commitments.

(c) See Note 5 of the notes to our consolidated financial statements in Item 8 of this report for a description of unrecognized tax benefits.

Chesapeake has commitments to purchase any natural gas and oil associated with certain volumetric production payment transactions based on market prices at the time of production and the purchased gas will be resold.

Under minimum volume throughput agreements, Chesapeake has agreed to move fixed volumes of natural gas over certain time periods, usually multiple years, through certain midstream systems. At the end of the term or annually, Chesapeake will be invoiced for any shortfalls in such volume commitments.

Hedging Activities

Natural Gas and Oil Hedging Activities

Our results of operations and 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, 2010, our natural gas and oil derivative instruments were comprised of swaps, call options, put options, knockout swaps and basis protection swaps. 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 our risk management objectives.

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

Mark-to-market positions under natural gas and oil derivative contracts fluctuate with commodity prices. As described above under *Hedging Facility*, our secured multi-counterparty hedging facility allows us to minimize the potential liquidity impact of significant mark-to-market fluctuations in the value of our natural gas and oil derivatives by pledging natural gas and oil proved reserves.

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The estimated fair values of our natural gas and oil derivative contracts as of December 31, 2010 and 2009 are provided below.

	December 31, 2010	December 31, 2009
	($ in millions)	
Derivative assets (liabilities)[a]:		
Fixed-price natural gas swaps	$ 1,307	$ 662
Natural gas call options	(701)	(541)
Natural gas put options	(59)	(50)
Fixed-price natural gas knockout swaps		17
Fixed-price natural gas collars		92
Natural gas basis protection swaps	(55)	(50)
Fixed-price oil swaps	(31)	3
Oil call options[b]	(1,129)	(144)
Fixed-price oil knockout swaps	19	32
Estimated fair value	$ (649)	$ 21

(a) See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* of this report for additional information concerning derivative transactions.

(b) During 2010 and 2009, we sold natural gas and oil call options on a portion of our projected production from 2011 to 2017 and received above-market fixed price natural gas swaps in 2010, 2011 and 2012.

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

	2010	2009	2008
		($ in millions)	
Fair value of contracts outstanding, as of January 1	$ 21	$ 1,305	$ (369)
Change in fair value of contracts	995	1,266	1,880
Fair value of new contracts when entered into	(581)	(21)	(569)
Contracts realized or otherwise settled	(1,691)	(2,102)	9
Fair value of contracts when closed	607	(427)	354
Fair value of contracts outstanding, as of December 31	$ (649)	$ 21	$ 1,305

Our realized and unrealized gains and losses on natural gas and oil derivatives during 2010, 2009 and 2008 were as follows:

	Years Ended December 31, 2010	2009	2008
		($ in millions)	
Natural gas and oil sales	$ 4,248	$ 3,291	$ 7,069
Realized gains (losses) on natural gas and oil derivatives[a]	2,056	2,346	(8)
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives[b]	(634)	(624)	887
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(23)	36	(90)

Total natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858

(a) Consists of settled trades related to the production periods being reported.

(b) Consists of both temporary fluctuations in the mark-to-market values of non-qualifying trades and settled values of non-qualifying trades related to future production periods.

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 settled 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 ($156) million, $94 million and $386 million as of December 31, 2010, 2009 and 2008, respectively. Based upon the market prices at

December 31, 2010, we expect to transfer to earnings approximately $15 million of net gain included in accumulated other comprehensive income during the next 12 months. A detailed explanation of accounting for natural gas and oil derivatives appears under *Application of Critical Accounting Policies Hedging* elsewhere in this Item 7.

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives.

For interest rate derivative contracts designated as fair value hedges, changes in fair values of the derivatives are recorded on the consolidated balance sheets as assets or (liabilities), with corresponding offsetting adjustments to the debt s carrying value. 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 interest expense and characterized as unrealized gains (losses).

Gains or losses from interest rate derivative contracts are reflected as adjustments to interest expense on the consolidated statements of operations. The components of interest expense for the years ended December 31, 2010, 2009 and 2008 are presented below.

	Years Ended December 31,		
	2010	2009	2008
	($ in millions)		
Interest expense on senior notes	$ 718	$ 765	$ 637
Interest expense on credit facilities	61	60	117
Capitalized interest	(716)	(633)	(585)
Realized (gains) losses on interest rate derivatives	(14)	(23)	(6)
Unrealized (gains) losses on interest rate derivatives	(66)	(91)	85
Amortization of loan discount and other	36	35	23
Total interest expense	$ 19	$ 113	$ 271

A detailed explanation of accounting for interest rate derivatives 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 appears under *Application of Critical Accounting Policies Hedging* elsewhere in this Item 7.

Results of Operations

General. For the year ended December 31, 2010, Chesapeake had net income of $1.774 billion, or $2.51 per diluted common share, on total revenues of $9.366 billion. This compares to a net loss of $5.830 billion, or $9.57 per diluted common share, on total revenues of $7.702 billion during the year ended December 31, 2009, and net income of $604 million, or $0.93 per diluted common share, on total revenues of $11.629 billion during the year ended December 31, 2008.

Natural Gas and Oil Sales. During 2010, natural gas and oil sales were $5.647 billion compared to $5.049 billion in 2009 and $7.858 billion in 2008. In 2010, Chesapeake produced and sold 1.035 tcfe of natural gas and oil at a weighted average price of $6.09 per mcfe, compared to 905.5 bcfe in 2009 at a weighted average price of $6.22 per mcfe, and 842.7 bcfe in 2008 at a weighted average price of $8.38 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of ($657) million, ($588) million and $797 million in 2010, 2009 and 2008, respectively). The decrease in prices in 2010 resulted in a decrease in revenue of $138 million and increased production resulted in a $807 million increase, for a total increase in revenues of $669 million (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.

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For 2010, we realized an average price per mcf of natural gas of $5.57, compared to $5.93 in 2009 and $8.09 in 2008 (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). Included in the 2010 realized price of natural gas are gains related to swaps that had an above-market fixed price on the origination date. We obtained these above-market swaps by selling out-year call options on a portion of our projected natural gas and oil production. See *Item 7A* for a complete listing of all of our derivative instruments. Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $62.71, $58.38 and $70.48 in 2010, 2009 and 2008, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $2.056 billion, or $1.99 per mcfe, in 2010, a net increase of $2.346 billion, or $2.59 per mcfe, in 2009 and a net decrease of $8 million, or $0.01 per mcfe, in 2008.

A change in natural gas and oil prices has a significant impact on our natural gas and oil revenues and cash flows. Assuming 2010 production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2010 revenues and cash flows of approximately $92 million and $89 million, respectively, and an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in 2010 revenues and cash flows of approximately $18 million and $17 million, respectively, without considering the effect of hedging activities.

The following tables show our production and prices by region for 2010, 2009 and 2008:

	2010						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Mid-Continent	233.2	4.09	13.8	56.60	315.9	31%	5.49
Haynesville/Bossier Shale	239.2	3.58			239.2	23	3.58
Barnett Shale	170.3	2.13	0.8	29.60	175.1	17	2.20
Fayetteville Shale	136.8	3.15			136.8	13	3.15
Permian and Delaware Basins	44.3	4.12	2.8	74.75	61.1	6	6.42
Marcellus Shale	51.2	3.91	0.3	42.09	53.0	5	4.01
Eagle Ford Shale	0.8	4.97	0.2	74.40	2.0		9.67
Rockies/Williston Basin	0.6	3.17	0.1	71.17	1.2		7.50
Other	48.5	3.68	0.4	69.69	50.9	5	4.08
Total[c]	924.9	3.43	18.4	58.67	1,035.2	100%	4.10

	2009						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Mid-Continent	258.7	3.78	7.7	55.25	304.8	34%	4.60
Haynesville/Bossier Shale	85.1	3.33	0.1	48.22	85.7	10	3.36
Barnett Shale	237.8	2.11	0.1	69.85	238.4	25	2.12
Fayetteville Shale	90.7	3.03			90.7	10	3.03
Permian and Delaware Basins	56.2	3.51	3.0	57.26	74.2	8	4.98
Marcellus Shale	21.9	4.30			21.9	2	4.30
Eagle Ford Shale							
Rockies/Williston Basin	0.6	1.46			0.6	1	1.46
Other	83.8	3.64	0.9	53.41	89.2	10	3.95
Total[c]	834.8	3.16	11.8	55.60	905.5	100%	3.63

	2008						
	Natural Gas		Oil[a]			Total	
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Mid-Continent	315.5	7.92	6.9	94.12	357.0	42%	8.82
Haynesville/Bossier Shale	30.4	8.35	0.2	95.12	31.6	4	8.64
Barnett Shale	181.2	6.74			181.2	21	6.74
Fayetteville Shale	54.9	7.24			54.9	7	7.24
Permian and Delaware Basins	62.2	7.84	2.7	97.66	78.4	9	9.59
Marcellus Shale	1.0	9.42			1.0		9.42
Eagle Ford Shale							
Rockies/Williston Basin	1.0	5.40	0.1	90.22	1.6	1	7.81
Other	129.2	8.75	1.3	94.83	137.0	16	9.16
Total[c]	775.4	7.74	11.2	95.04	842.7	100%	8.39

(a) Includes NGLs

(b) The average sales price excludes gains (losses) on derivatives.

(c) 2010 production reflects the sale of a 25% industry participation interest in the company s Barnett Shale assets in January 2010 and various other asset sales, including VPP 6, VPP 7 and VPP 8.

Our average daily production of 2.836 bcfe for 2010 consisted of 2.534 bcf of natural gas and 50,397 bbls of oil. Our 2010 production of 1.035 tcfe was comprised of 924.9 bcf (89% on a natural gas equivalent basis) and 18.4 mmbbls (11% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 11% and our year-over-year growth rate of oil production was 56%. Our percentage of revenue from oil in 2010 was 18% of realized natural gas and oil revenue compared to 12% in 2009.

Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression sales and operating expenses consist of third-party revenue and operating expenses related to our midstream operations. Marketing, gathering and compression activities are performed by Chesapeake substantially for owners in Chesapeake-operated wells. Chesapeake realized $3.479 billion in marketing, gathering and compression sales in 2010, with corresponding marketing, gathering and compression expenses of $3.352 billion, for a net margin before depreciation of $127 million. This compares to sales of $2.463 billion and $3.598 billion, expenses of $2.316 billion and $3.505 billion, and margins before depreciation of $147 million and $93 million in 2009 and 2008, respectively. In 2010, Chesapeake realized an increase in marketing, gathering and compression sales and operating expenses primarily due to an increase in third-party marketing, gathering and compression volumes. This increase was offset by a decrease in revenues, expenses and margin related to certain of our midstream assets that were contributed to our midstream joint venture on September 30, 2009 and subsequently deconsolidated on January 1, 2010. In 2009, Chesapeake realized an increase in marketing, gathering and compression net margin primarily due to an increase in third-party marketing, gathering and compression volumes.

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 $240 million in service operations revenue in 2010 with corresponding service operations expenses of $208 million, for a net margin before depreciation of $32 million. This compares to revenue of $190 million and $173 million, expenses of $182 million and $143 million and a net margin before depreciation of $8 million and $30 million in 2009 and 2008, respectively. Service operations margins have increased as service rates increased throughout 2010. The economic slowdown toward the end of 2008 and throughout 2009 caused decreased service rates and increased stacked rigs, resulting in much lower operating margins for 2009 when compared to 2010 and 2008.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $893 million in 2010, compared to $876 million and $889 million in 2009 and 2008, respectively. On a unit-of-production basis, production expenses were $0.86 per mcfe in 2010 compared to $0.97 and $1.05 per mcfe in 2009 and 2008, respectively. The per unit expense decreases in 2010 and 2009 were primarily the result of completing new high volume wells with lower per unit production costs.

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The following table shows our production expenses by region and our ad valorem tax expenses for 2010, 2009 and 2008 ($ in millions, except per unit):

	2010		2009		2008	
	Production Expenses	$/mcfe	Production Expenses	$/mcfe	Production Expenses	$/mcfe
Mid-Continent	$ 309	0.98	$ 300	$ 0.98	$ 362	1.01
Haynesville/Bossier Shale	65	0.27	33	0.39	37	1.33
Barnett Shale	142	0.81	158	0.66	128	0.71
Fayetteville Shale	40	0.29	23	0.25	13	0.24
Permian and Delaware Basins	94	1.54	112	1.52	134	1.67
Marcellus Shale	37	1.08	24	1.10	4	1.63
Eagle Ford Shale	3	1.50				
Rockies/Williston Basin	2	1.67	2			
Other	136	1.76	144	1.61	137	1.00
	828	0.80	796	0.88	815	0.96
Ad valorem tax	65	0.06	80	0.09	74	0.09
Total	$ 893	0.86	$ 876	0.97	$ 889	1.05

Production Taxes. Production taxes were $157 million in 2010 compared to $107 million in 2009 and $284 million in 2008. On a unit-of-production basis, production taxes were $0.15 per mcfe in 2010 compared to $0.12 per mcfe in 2009 and $0.34 per mcfe in 2008. The $50 million increase in production taxes from 2009 to 2010 is due to an increase in the realized average sales price of natural gas and oil of $0.47 per mcfe (excluding gains or losses on derivatives), and a production increase of 129.7 bcfe. The decrease in 2009 was due to a decrease in the realized average sales price of natural gas and oil of $4.76 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.

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 the notes to our consolidated financial statements included in Item 8 of this report), were $453 million in 2010, $349 million in 2009 and $377 million in 2008. General and administrative expenses were $0.44, $0.38 and $0.45 per mcfe for 2010, 2009 and 2008, respectively. The increase in 2010 is the result of the company s continued growth resulting in higher payroll and associated costs. The decrease in 2009 was primarily the result of decreased spending related to media relations. Included in general and administrative expenses is stock-based compensation of $84 million in 2010, $83 million in 2009 and $85 million in 2008. Restricted stock grants expense is based on the price of our common stock on the date of grant.

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 the notes to our 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. In addition, we capitalize internal costs that can be identified with construction of certain of our property, plant and equipment. We capitalized $384 million, $359 million and $352 million of internal costs in 2010, 2009 and 2008, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts and the construction of our property, plant and equipment.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $1.394 billion, $1.371 billion and $1.970 billion during 2010, 2009 and 2008, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $1.35, $1.51 and $2.34 in 2010, 2009 and 2008, respectively. The decrease in the average rate from $2.34 in 2008 to $1.35 in 2010 is due primarily to reductions of our natural gas and oil full-cost pool resulting from our divestitures in 2008, 2009 and 2010, impairments of our full-cost pool in 2008 and 2009 as well as the addition of reserves through our drilling activities.

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Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $220 million in 2010, compared to $244 million in 2009 and $174 million in 2008. The average DD&A rate per mcfe was $0.21, $0.27 and $0.21 in 2010, 2009 and 2008, respectively. The decrease from 2009 to 2010 was primarily due to certain of our midstream assets that were contributed to our midstream joint venture on September 30, 2009 and subsequently deconsolidated on January 1, 2010, offset by additional depreciation expense associated with the assets acquired over the past year. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 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 twenty 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.

Impairment of Natural Gas and Oil Properties. Due to lower commodity prices in the second half of 2008 and throughout 2009, we reported a non-cash impairment charge on our natural gas and oil properties of $11.0 billion in 2009 and $2.8 billion in 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 pricing and cost assumptions prescribed by the SEC and the present value of certain natural gas and oil hedges.

(Gains) Losses on Sales of Other Property and Equipment. In 2010, we recorded a ($137) million gain associated with sales of other property and equipment which consisted of a ($157) million gain on the sale of our Springridge gas gathering system to our affiliate, CHKM, and a net $20 million loss related to various sales of other property and equipment, including the sale of pipe, gas gathering systems and other miscellaneous assets. In 2009, we recorded a $38 million loss on the sale of two gathering systems. There were nominal amounts of gains and losses on the sales of other property and equipment in 2008.

Other Impairments. In 2010, we recorded a $21 million impairment to natural gas gathering systems primarily related to the obsolescence of certain pipe inventory. In 2009, we recorded a $130 million impairment of other property and equipment and other assets. An $86 million impairment was associated with certain of our midstream assets contributed to our midstream joint venture in September 2009, as well as a $4 million impairment of debt issuance costs associated with the portion of our $460 million midstream revolving bank credit facility that was reduced to $250 million as a result of the joint venture. Also in 2009, we recognized a $27 million charge associated with certain of our service operations assets and $13 million of bad debt expense related to potentially uncollectible receivables. In 2008, we recorded a $30 million impairment associated with certain of our midstream assets.

Restructuring Costs. In 2009, we recorded $34 million of restructuring and relocation costs in our Eastern Division and certain other workforce reduction costs. We reorganized our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model we use elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the restructuring included termination benefits, consolidating or closing facilities and relocating employees. The discussion of restructuring costs in Note 13 of our consolidated financial statements included in Item 8 of this report provides additional detail on the accounting for and reporting of these costs.

Interest Expense. Interest expense decreased to $19 million in 2010 compared to $113 million in 2009 and $271 million in 2008 as follows:

	Years Ended December 31,		
	2010	2009	2008
	($ in millions)		
Interest expense on senior notes	$ 718	$ 765	$ 637
Interest expense on credit facilities	61	60	117
Capitalized interest	(716)	(633)	(585)
Realized (gains) losses on interest rate derivatives	(14)	(23)	(6)
Unrealized (gains) losses on interest rate derivatives	(66)	(91)	85
Amortization of loan discount and other	36	35	23
Total interest expense	$ 19	$ 113	$ 271
Average long-term borrowings	$ 10,345	$ 11,167	$ 10,044

Interest expense, excluding unrealized (gains) losses on interest rate derivatives, was $0.08 per mcfe in 2010 compared to $0.22 per mcfe in both 2009 and 2008. The decrease in interest expense per mcfe from 2009 and 2008 is due to increased production volumes, a decrease in our senior notes outstanding and an increase in capitalized interest. Capitalized interest increased in 2010 and 2009 as a result of a significant increase in unevaluated properties, the base on which interest is capitalized.

Earnings (Losses) from Equity Investees. Earnings (losses) from equity investees was $227 million, ($39) million and ($38) million in 2010, 2009 and 2008, respectively. The 2010 income consisted of $106 million related to our equity in the net income of certain investments and $121 million related to the initial public offering by CHKM and a private offering of common stock by Chaparral Energy, Inc., which represented our proportionate share of the excess of offering proceeds over our carrying value. The 2009 and 2008 losses related to our equity in the net losses of certain investments.

Loss on Redemptions or Exchanges of Debt. During 2010, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in principal amount of our 6.875% Senior Notes due 2016. Associated with the redemptions, we recognized a loss of $69 million in 2010. Also during 2010, we redeemed in whole for a redemption price of approximately $619 million, plus accrued interest, all $600 million in principal amount of our 6.375% Senior Notes due 2015. We recognized a loss of $19 million in 2010 associated with the redemptions.

Additionally during 2010, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. Following the completion of these tender offers, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with these tender offers and redemptions, we recognized a loss of $40 million in 2010.

Finally, in 2010, we privately exchanged approximately $11 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 298,500 shares of our common stock valued at approximately $9 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 80% of the face value of the notes. Of the $11 million principal amount of convertible notes exchanged in 2010, $7 million was allocated to the debt component of the notes and the remaining $4 million was allocated to the equity conversion feature of the notes and was recorded as an adjustment to paid-in-capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in the $2 million loss (including a nominal amount of deferred charges associated with the exchanges).

In 2009, we privately exchanged approximately $364 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 10,210,169 shares of our common stock valued at approximately $262 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 75% of the face value of the notes. Of the $364 million principal amount of convertible notes exchanged in 2009, $227 million was allocated to the debt component and the remaining $137 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in a $40 million loss (including $5 million of deferred charges associated with the exchanges).

During 2008, we exchanged approximately $254 million, $272 million and $239 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038, 2.50% Contingent Convertible Senior Notes due 2037, and 2.75% Contingent Convertible Senior Notes due 2035, respectively, for an aggregate of 23,913,212 shares of our common stock valued at approximately $480 million. Through these transactions, we were able to redeem this debt for common stock valued at approximately 65% of the face value of the notes. Associated with these exchanges, we recorded a gain of $27 million. Of the combined $765 million principal amount of convertible notes exchanged in 2008, $515 million was allocated to the debt component and the remaining $250 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The difference between the debt component and the value of the common stock exchanged in these transactions resulted in a $35 million gain. This gain was partially offset by the write-off of $8 million in deferred charges associated with these exchanges.

Also during 2008, we repurchased $300 million of our 7.75% Senior Notes due 2015 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction, we recorded a $31 million loss, which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

Impairment of Investments. We recorded $16 million, $162 million and $180 million of impairments of certain investments in 2010, 2009 and 2008, respectively. 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 and 2010. 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 certain investments.

Other Income. Other income was $16 million, $11 million and $27 million in 2010, 2009 and 2008, respectively. The 2010 income consisted of $8 million of interest income and $8 million of miscellaneous income. The 2009 income consisted of $8 million of interest income and $3 million of miscellaneous income. The 2008 income consisted of $22 million of interest income, $10 million of expense related to consent solicitation fees and $15 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $1.110 billion in 2010 compared to an income tax benefit of $3.483 billion in 2009 and income tax expense of $387 million in 2008. The entire income tax expense recorded in 2010 is deferred. Of the $4.593 billion increase in 2010, $4.564 billion was the result of the increase in net income before taxes and $29 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in 2010 compared to 37.5% in 2009 and 39% in 2008. 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 2011.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $67 million in 2008. There were no losses on conversion/exchange of preferred stock in 2010 and 2009. In general, 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 the notes to our consolidated financial statements in Item 8 of this report 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 three policies we consider to be the most significant are discussed below. The company s management has discussed each critical accounting policy with the Audit Committee of the company s Board of Directors.

The selection and application of accounting policies 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 and changes in interest rates and 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 contracts are reflected in natural gas and oil sales, and results of interest rate and foreign exchange rate hedging contracts 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 contracts 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.

Accounting guidance for derivatives and hedging 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 natural gas and oil 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 as natural gas and oil sales. Any change in the fair value resulting from ineffectiveness is recognized immediately in natural gas and oil sales. For derivative instruments designated as fair value hedges, 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 as interest expense. 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 as interest expense. See *Hedging Activities* above and Item 7A. *Quantitative and Qualitative Disclosures About Market Ris*k 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.

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, 2010, 2009 and 2008, the fair value of our derivatives was a liability of $761 million, a liability of $63 million and an asset of $1.165 billion, respectively.

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 or future development costs changes significantly. Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in proved reserves and significantly alter 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. For 2010 and 2009, in calculating estimated future net revenues, current prices are calculated as the unweighted arithmetic average of natural gas and oil prices on the first day of each month within the 12-month period ended. Costs used are those as of the end of the appropriate quarterly period. For 2008, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges.

Two primary factors impacting this test are reserve levels and natural gas and oil 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.

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 accounting guidance 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 (i) the more positive evidence is necessary and (ii) 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 the tax benefit;
- 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 (i) natural gas and oil prices were to decrease significantly below present levels (and if such decreases were considered other than temporary), (ii) exploration, drilling and operating costs were to increase significantly beyond current levels, or (iii) 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, 2010, we had deferred tax assets of $1.9 billion.

Accounting guidance for recognizing and measuring uncertain tax positions 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. 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

Note 5 of the notes to our consolidated financial statements.

Disclosures About Effects of Transactions with Related Parties

Chief Executive Officer

As of December 31, 2010, we had accrued accounts receivable from our Chief Executive Officer, Aubrey K. McClendon, of $30 million representing joint interest billings from December 2010 which were invoiced and timely paid in January 2011. Since Chesapeake was founded in 1989, Mr. 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 are recognizing 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 was fully 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 equal to any unvested portion of the award 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.

Other Related Parties

During 2010, our 42%-owned affiliate, Chesapeake Midstream Partners, L.P. (CHKM), provided natural gas gathering and treating services to us in the ordinary course of business. In addition, there are various agreements in place whereby we support CHKM in various functions for which we are reimbursed. During 2010, our transactions with CHKM included the following:

	Year Ended December 31, 2010 ($ in millions)
Amounts paid to CHKM:	
Gas gathering fees	$ 378
Amounts received from CHKM:	
Compressor rentals	48
Inventory purchases	47
Other services provided[(a)]	73
Total amounts received from CHKM	$ 168

(a) Includes amounts received related to the General and Administrative Services and Reimbursement Agreement, the Employee Secondment Agreement, the Shared Services Agreement and the Additional Services and Reimbursement Agreement agreed to at the formation of the joint venture.

As of December 31, 2010, we had a net payable to CHKM of $45 million.

During 2010 and 2009, our 26%-owned affiliate, Frac Tech Holdings, LLC, provided us hydraulic fracturing and other services in the ordinary course of business. During 2010 and 2009, we paid Frac Tech $89 million and $43 million, respectively, for these services. As of December 31, 2010 and 2009, we had $30 million and $8 million, respectively, due Frac Tech for services provided and not yet paid.

Recently Issued Accounting Standards

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

In February 2010, the FASB amended its guidance on subsequent events to remove the requirement for SEC filers to disclose the date through which an entity has evaluated subsequent events. The guidance was effective upon issuance. We adopted this guidance in 2010.

The FASB also issued new guidance requiring additional disclosures about fair value measurements, adding a new requirement to disclose transfers in and out of Levels 1 and 2 measurements and gross presentation of activity within a Level 3 roll forward. The guidance also clarified existing disclosure requirements regarding the level of disaggregation of fair value measurements and disclosures regarding inputs and valuation techniques. We adopted this guidance in the Current Period. Adoption had no impact on our financial position or results of operations. Required disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method are effective beginning on January 1, 2011, and we do not expect the implementation to have a material impact on our financial position or results of operations. See Note 14 of the notes to our consolidated financial statements in Item 8 of this report for discussion regarding fair value measurements.

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 are statements other than historical fact and 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.

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;
- 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;
- inability to generate profits or achieve targeted results in our development and exploratory drilling and well operations;

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;

drilling and operating risks, including potential environmental liabilities;

changes in legislation and regulation adversely affecting our industry and our business;

general economic conditions negatively impacting us and our business counterparties;

transportation capacity constraints and interruptions that could adversely affect our cash flow; and

losses possible from pending or future litigation.

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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 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. 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 our risk management objectives.

Our general strategy for attempting to mitigate exposure to adverse natural gas and oil price changes is to hedge into strengthening natural gas and oil futures markets when prices allow us to generate high cash margins and when we view prices to be in the upper range of our predicted future price range. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas import trends, natural gas and oil storage inventory levels, industry decline rates for base production and weather trends.

We use a wide range of derivative instruments to achieve our risk management objectives, including swaps and options (puts or calls). All of these are described in more detail below. We typically use swaps for a large portion of the natural gas and oil volume we hedge. Swaps are used when the price level is acceptable. We also sell calls, taking advantage of market volatility for a portion of our projected production volumes when the strike price levels and the premiums are attractive to us. Beginning in late 2009 and in 2010, we have taken advantage of attractive strip prices in 2012 through 2017 and sold natural gas and oil call options to our counterparties in exchange for 2010, 2011 and 2012 natural gas swaps with fixed prices above the then current market price. This effectively allowed us to sell out-year volatility through call options at terms acceptable to us in exchange for natural gas swaps with fixed prices in excess of the market price for natural gas at that time. Additionally, we sell call options when we would be satisfied to sell our production at the price being capped by the call strike or believe it to be more likely than not that the future natural gas or oil price will stay below the call strike price plus the premium we will receive.

We determine the volume we may potentially hedge by reviewing the company s estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of likely production (risked) from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not hedge more volumes than we expect to produce, and if production estimates are lowered for future periods and hedges are already executed for some volume above the new production forecasts, the hedges are reversed. The actual fixed hedge price on our derivative instruments is derived from bidding and the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures. All of our derivative instruments are net settled based on the difference between the fixed price as stated in the contract and the floating-price payment, resulting in a net amount due to or from the counterparty.

We adjust our derivative positions in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our derivative positions continuously and if future market conditions change and prices have fallen to levels we believe could jeopardize the effectiveness of a position, we will mitigate such risk by either doing a cash settlement with our counterparty, restructuring the position, or by entering into a new swap that effectively reverses the current position (a counter-swap). The factors we consider in closing or restructuring a position before the settlement date are identical to those we reviewed when deciding to enter into the original derivative position. Gains or losses related to closed positions will be realized in the month of related production based on the terms specified in the original contract.

In 2009, we restructured many of our contracts that included knockout features as commodity prices decreased. The knockouts were typically restructured into straight swaps or collars based on strip prices at the time of the restructure. In the latter half of 2010, we restructured a portion of our call options by lowering the strike price on call options sold for 2012 through 2015 and used the value to buy back call options for the same periods. This increased our capacity to hedge additional volumes.

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As of December 31, 2010, our natural gas and oil derivative instruments consisted of the following:

Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.

Call options: Chesapeake sells call options in exchange for a premium from the counterparty. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.

Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. At the time of settlement, if the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall, and if the market price settles above the fixed price of the put option, no payment is due from either party.

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.

Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin 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.

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As of December 31, 2010, we had the following open natural gas and oil derivative instruments.

	Volume (bbtu)	Fixed	Weighted Average Price (per mmbtu) Put	Call	Differential	Cash Flow Hedge	Fair Value ($ in millions)
Natural Gas:							
Swaps:							
Q1 2011	89,354	$ 5.60	$	$	$	Yes	$ 111
Q2 2011	91,023	5.35				Yes	83
Q3 2011	132,480	4.93				Yes	47
Q4 2011	132,480	4.93				Yes	8
2012	12,800	6.00				Yes	12
Other Swaps[(a)]:							
Q1 2011	142,545	6.43				No	298
Q2 2011	140,512	6.35				No	268
Q3 2011	85,880	6.70				No	183
Q4 2011	85,880	6.73				No	159
2012	122,180	6.19				No	138
Call Options:							
2012	161,077			6.54		No	(39)
2013	436,033			6.44		No	(171)
2014	330,183			6.44		No	(165)
2015	226,446			6.31		No	(140)
2016 2020	324,003			8.31		No	(186)
Put Options:							
Q1 2011	(9,000)		5.75			No	(13)
Q2 2011	(9,100)		5.75			No	(12)
Q3 2011	(16,560)		5.42			No	(18)
Q4 2011	(16,560)		5.48			No	(16)
Basis Protection Swaps (Non-Appalachian Basin):							
Q2 2011	19,147				(0.82)	No	(10)
Q3 2011	19,397				(0.82)	No	(10)
Q4 2011	6,545				(0.82)	No	(3)
2012	50,532				(0.78)	No	(22)
2013 2019	29,349				(0.69)	No	(9)
Basis Protection Swaps (Appalachian Basin):							
Q1 2011	11,674				0.14	No	(1)
Q2 2011	12,186				0.14	No	
Q3 2011	12,403				0.14	No	
Q4 2011	12,324				0.14	No	
2012 2022	134				0.11	No	
	Total Natural Gas						492

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	Volume (bbtu)	Fixed	Weighted Average Price Put	Call	Differential	Cash Flow Hedge	Fair Value ($ in millions)
			(per mmbtu)				
Oil:							
Swaps:							
Q1 2011	180	$ 91.35	$	$	$	Yes	$
Q2 2011	182	91.35				Yes	
Q3 2011	184	91.35				Yes	(1)
Q4 2011	184	91.35				Yes	(1)
Other Swaps[a]:							
2012	1,830	100.00				No	(13)
2013	1,825	100.00				No	(16)
Call Options[b]:							
Q1 2011	2,250			72.81		No	(28)
Q2 2011	2,275			72.81		No	(33)
Q3 2011	2,300			72.81		No	(37)
Q4 2011	2,300			72.81		No	(40)
2012	15,644			79.82		No	(258)
2013	12,739			85.37		No	(226)
2014	8,707			87.72		No	(151)
2015	7,411			85.31		No	(140)
2016 2017	10,600			84.25		No	(216)
Knock-Out Swaps:							
Q1 2011	270	104.75	60.00			No	3
Q2 2011	273	104.75	60.00			No	3
Q3 2011	276	104.75	60.00			No	3
Q4 2011	276	104.75	60.00			No	2
2012	732	109.50	60.00			No	8
	Total Oil						(1,141)
Total Natural Gas and Oil							$