CHESAPEAKE ENERGY CORP (CHK)

10-K

Annual report pursuant to section 13 and 15(d)
Filed on 02/29/2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the Fiscal Year Ended December 31, 2011

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

(405) 848-8000

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $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
6.775% Senior Notes due 2019	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 ☒ NO ☐

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

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

Indicate by check mark 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 ☒ 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 ☒ 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 ☒

The aggregate market value of our common stock held by non-affiliates on June 30, 2011 was approximately $19.4 billion. At February 22, 2012, there were 662,498,825 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2012 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

2011 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, a top 15 producer of oil and natural gas liquids (collectively "liquids") and the most active driller of new wells in the U.S. We own interests in approximately 45,700 producing natural gas and oil wells that are currently producing approximately 3.5 billion cubic feet of natural gas equivalent (bcfe) per day, net to our interest. Our business strategy is focused on discovering and developing large accumulations of natural gas resources in the Haynesville and Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania; the Barnett Shale in the Fort Worth Basin of north-central Texas; and the Pearsall Shale in South Texas. In addition, we have built leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas; the Utica Shale in Ohio and Pennsylvania; the Granite Wash, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in western Oklahoma and the Texas Panhandle; the Bone Spring, Avalon, Wolfcamp and Wolfberry plays in the Permian and Delaware Basins in West Texas and southern New Mexico; and the Niobrara Shale in the Powder River Basin in Wyoming.

We have also vertically integrated many of our operations and own substantial marketing, compression, midstream and oilfield services businesses. Our marketing business is named Chesapeake Energy Marketing, Inc. (CEMI) and is a top 10 marketer of natural gas in the U.S. and one of the largest liquids marketers as well. Our compression business is conducted under MidCon Compression, L.L.C. (MidCon) and its assets include over 1.0 million horsepower of compression, making MidCon the second largest compression company in the U.S. Our midstream operations consist of wholly owned Chesapeake Midstream Development, L.P. (CMD) and a 46% investment in Chesapeake Midstream Partners, L.P. (NYSE: CHKM). Our oilfield services business is conducted under the name Chesapeake Oilfield Services, L.L.C. (COS) and its primary operating subsidiaries include Nomac Drilling, L.L.C., the nation's fourth largest drilling contractor, Thunder Oilfield Services L.L.C., which owns one of the largest oilfield trucking and oilfield equipment rental businesses, and Performance Technologies, L.L.C., our pressure pumping business, which we believe will become one of the nation's five largest pressure pumping businesses in the next few years. Our ownership of these marketing, compression, midstream and oilfield service businesses improves our efficiency, scale, safety and profitability.

We have been developing expertise in horizontal drilling technology since shortly after our formation 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 10 years, we have grown from the 12th 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 recognition of the value gap between oil and natural gas prices that has widened to historic levels in the last three years, Chesapeake has directed a significant portion of its technological and leasehold acquisition expertise to identify, secure and commercialize new unconventional liquids-rich plays. This planned transition will result in a more balanced and likely more profitable portfolio between natural gas and liquids. To date, we have built leasehold positions and established production in multiple liquids-rich plays on approximately 6.6 million net acres. Our production of liquids averaged approximately 86,800 barrels (bbls) per day during 2011, a 72% increase over the average during 2010, as a result of the increased development of our unconventional liquids-rich plays. In 2011, approximately 50% of our drilling and completion expenditures were allocated to liquids-rich plays, compared to 30% in 2010 and 10% in 2009. We are projecting that the portion of our operated drilling

and completion expenditures allocated to liquids development will reach 85% in 2012, and we expect to increase our liquids production through our drilling activities to an average of approximately 150,000 bbls per day in 2012 and to more than 200,000 bbls per day in 2013 and 250,000 bbls per day by 2015.

During 2011, our estimated proved reserves grew from 17.096 trillion cubic feet of natural gas equivalent (tcfe) to 18.789 tcfe, 54% of which was proved developed and 100% was onshore in the U.S. We replaced our 1.194 tcfe of 2011 production with an estimated 2.887 tcfe of new proved reserves for a reserve replacement rate of 242%. The 2011 proved reserve movement included 5.683 tcfe of extensions, 64 bcfe of negative performance revisions to previous estimates and 14 bcfe of positive revisions resulting from higher oil prices using the average first-day-of-the-month price for the twelve months ended December 31, 2011, compared to the twelve months ended December 31, 2010. During 2011, we acquired 30 bcfe of estimated proved reserves and divested 2.776 tcfe of estimated proved reserves, including the disposition of 2.420 tcfe associated with the sale of our Fayetteville Shale assets for $4.65 billion in March 2011. The 64 bcfe of negative revisions to previous estimates consisted of 337 bcfe of negative revisions associated with the deletion of proved undeveloped reserves no longer consistent with our development plans, offset by 273 bcfe of positive revisions to producing properties and proved undeveloped reserves estimates.

Daily production for 2011 averaged 3.272 bcfe, an increase of 436 million cubic feet of natural gas equivalent (mmcfe), or 15%, over the 2.836 bcfe of daily production for 2010 and consisted of 2.751 billion cubic feet of natural gas (bcf) (84% on a natural gas equivalent basis) and 86,784 bbls of liquids (16% on a natural gas equivalent basis). Our natural gas production in 2011 grew by 9%, or 217 mmcf per day, and our liquids production increased by 72%, or 36,386 bbls per day. This was our 22nd consecutive year of sequential production growth.

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 news releases. References to "Chesapeake", the "Company", "us", "we" and "our" in this report are to Chesapeake Energy Corporation together with its subsidiaries, unless the context otherwise requires.

Recent Developments

Update to Operating Plan in Response to Low Natural Gas Prices

On February 13, 2012, in response to the lowest natural gas prices the U.S. has experienced in the past 10 years, we announced that we have taken a series of steps outlined below.

First, we are reducing our operated dry gas drilling activity to approximately 24 rigs by the second quarter of 2012 from 47 dry gas rigs in use in January 2012 and from an average of 75 dry gas rigs used during 2011. Our operated dry gas drilling and completion expenditures in 2012, net of drilling carries, are expected to decrease to $900 million, or approximately 70%, from similar expenditures of $3.1 billion in 2011.

Second, we have curtailed approximately 1.0 bcf per day of gross operated natural gas production, or approximately 1.5% of U.S. lower 48 natural gas production. The curtailed volumes are located primarily in the Haynesville and Barnett Shale plays and have been implemented to minimize

the impact of existing midstream and transportation commitments. In addition, wherever possible, we are deferring completions of dry gas wells that have been drilled but not yet completed, and we are also deferring pipeline connections to dry gas wells that have already been completed.

Third, we have reallocated capital from reduced dry gas drilling, well completion and pipeline connection activities to our liquids-rich plays that offer superior returns in the current strong liquids price environment. This reallocation will result in increased expenditures in certain of our liquids-rich plays, including the Eagle Ford Shale, Utica Shale, Mississippi Lime, Granite Wash, Cleveland, Tonkawa, Niobrara, Bone Spring, Avalon, Wolfcamp and Wolfberry plays. We estimate that approximately 85% of our 2012 total net operated drilling and completion expenditures will be invested in our liquids-rich plays.

Fourth, we plan to further reduce our undeveloped leasehold expenditures, the majority of which have been focused on acquiring leading positions in liquids-rich plays during the past three years. We are now targeting to invest approximately $1.4 billion in undeveloped leasehold expenditures in 2012, net of ongoing joint venture reimbursements, of which approximately 90% will be in liquids-rich plays and 100% will be in plays where we are already active. This compares to undeveloped leasehold expenditures of approximately $3.5 billion and $5.8 billion in 2011 and 2010, respectively.

Update to Financial Plan

Our business strategy is to continue our reserves and production growth and transition to increased liquids production. As a result of this strategy, we plan to make capital expenditures in 2012 that will exceed our projected cash flow from operations. We plan to obtain funds for these capital expenditures from operating cash flow, supplemented by various asset monetization transactions, including joint ventures, volumetric production payments, financial transactions and other property and investment dispositions.

We recently announced that we are pursuing a volumetric production payment transaction in our Texas Panhandle Granite Wash play and a financial transaction in our Cleveland and Tonkawa plays (similar to our recent CHK Utica financial transaction), and we are targeting to close each of these transactions by the end of the 2012 first quarter. Additionally, we are pursuing a joint venture transaction in our Mississippi Lime play in northern Oklahoma and southern Kansas, where we own approximately 1.8 million net acres today and expect to own approximately 2.0 million net acres at the time of the joint venture closing, and in the Permian Basin in West Texas and southern New Mexico, where we own approximately 1.5 million net acres. We may also consider the sale of all of our interests in the Permian Basin. Our Permian Basin assets represent approximately 5% of the Company's total proved reserves and current net production. We are targeting completion of the Mississippi Lime and Permian Basin transactions by the end of the 2012 third quarter. Finally, we plan to continue to seek monetizations of a portion of our midstream assets, our oilfield services assets and other miscellaneous investments. While we expect that the proceeds from these transactions will be sufficient to fund our planned capital expenditures, we do not have binding agreements for any of these transactions and our ability to consummate each of these transactions is subject to changes in market conditions and other factors. As a result, there can be no assurance that we will complete any of these transactions on a timely basis or at all. To the extent that proceeds from these potential transactions are inadequate to fund our planned spending, we would be required to modify our drilling program or monetize different or additional assets.

Update to 25/25 Plan

Our 25/25 Plan calls for our long-term debt to be no more than $9.5 billion as of December 31, 2012 and for us to increase our production by 25% during the two-year period ended December 31, 2012. Our long-term debt (net of cash) as of December 31, 2011 was approximately $10.3 billion, a reduction of $2.2 billion from the year-end 2010 level of $12.5 billion. We plan to reduce our indebtedness to no more than our stated goal of $9.5 billion by year-end 2012 primarily with the proceeds from the asset monetization transactions described above.

Business Strategy

Since our inception in 1989, Chesapeake's primary goal has been to create value for investors by building and developing one of the largest onshore natural gas and liquids-rich resource bases in the U.S. 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 proved reserves organically through the drillbit at low cost in areas with large unconventional accumulations of natural gas and liquids. We are currently utilizing 161 operated drilling rigs and 100 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 horizontal wells than any other company in the industry. For many years, we have been actively investing large amounts of capital in undeveloped leasehold, three dimensional (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 22 consecutive years. We believe the key elements of the success and scale of our drilling program have been our recognition, earlier than most of our competitors, that advanced horizontal drilling and completion techniques would enable development of previously uneconomic natural gas and liquids-rich reservoirs and that, as a consequence, various unconventional formations could be recognized and developed as potentially prolific reservoirs. In response to our early recognition of these trends, we have proactively hired thousands of new employees and have built 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 reservoirs, 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 through 2011. 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, 2011, we held approximately 15.3 million net acres of onshore leasehold in the U.S. and have identified approximately 39,200 drilling opportunities on this leasehold. We believe this extensive backlog of drilling, approximately 20 years worth at current drilling levels, provides strong evidence of our future growth capabilities. We further believe that our U.S.-based undeveloped leasehold acquisition phase is now substantially complete. We spent significantly less on new leasehold in 2011 than in 2010 and are forecasting even lower undeveloped leasehold acquisition expenditures in 2012.

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 expenses, 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 not investing offshore and internationally, we expect to continue to achieve the significant benefits of focus and scale.

Develop Proprietary Technological Advantages. In addition to our industry-leading undeveloped leasehold position, we have developed a number of proprietary technological advantages. First, we have acquired the nation's largest inventory of 3-D seismic information. Possessing this 3-D seismic

data enables us to image reservoirs of natural gas and liquids 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 unequalled insight into new plays and competitor activity. As a result of our initiatives, we now produce approximately 9% of the nation's natural gas, drill approximately 8% 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 we target.

Focus on Low Costs and Vertical Integration. By minimizing lease operating expenses 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, especially our own through COS, and natural gas processing and transportation infrastructures that exist in our key operating areas. Our high level of drilling activity and production volumes will create considerable value for the providers of oilfield services and compression and midstream gathering services. Our strategy is to capture a portion of this value for our shareholders rather than transfer it to third-party vendors. As of December 31, 2011, we operated approximately 24,800 of our 45,700 wells, which delivered approximately 85% 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 our hedging program to mitigate the risks inherent in developing and producing natural gas and liquids-rich resources, 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.

Form Value-Creating Joint Ventures. As of December 31, 2011, we had entered into seven significant joint ventures with other leading energy companies pursuant to which we sold a minority interest in our leasehold, producing properties and other assets located in seven different resource plays and received cash of $7.1 billion and commitments for future drilling and completion cost sharing of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all

leasing, drilling, completion, operations and marketing activities for the project. These transactions have allowed us to recover much or all of our initial leasehold investments and reduce our ongoing capital costs in these plays. The transactions are detailed below.

Primary Play	Joint Venture Partner[a]	Joint Venture Date	Interest Sold	Cash Proceeds Received at Closing	Total Drilling Carries	Drilling Carries Remaining[b]
				($ in millions)		
Utica	TOT	December 2011	25.0%	$ 610	$ 1,422	$ 1,422
Niobrara	CNOOC	February 2011	33.3%	570	697	570
Eagle Ford & Pearsall	CNOOC	November 2010	33.3%	1,120	1,080	144
Barnett	TOT	January 2010	25.0%	800	1,404[c]	—
Marcellus	STO	November 2008	32.5%	1,250	2,125	223
Fayetteville	BP	September 2008	25.0%	1,100	800	—
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508[d]	—
				$ 7,100	$ 9,036	$ 2,359

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

(b) As of December 31, 2011.

(c) In conjunction with an agreement requiring us to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012, TOT accelerated the payment of its remaining joint venture drilling carry in exchange for an approximate 9% reduction in the total amount of drilling carry obligation owed to us at that time. As a result, in October 2011, we received $471 million in cash from TOT, which included $46 million of carry obligation billed and $425 million for the remaining carry obligation. In January 2012, Chesapeake and TOT agreed to reduce the minimum rig count from 12 to six rigs.

(d) In September 2009, PXP accelerated the payment of its remaining carry in exchange for an approximate 12% reduction to the remaining drilling carry obligation owed to us at that time.

Improve Our Balance Sheet through Reduction of Debt. Our 2011 – 2012 strategic and financial plan calls for a 25% reduction in our long-term debt while growing net natural gas and liquids 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 $0.55 per mcfe at year-end 2011 and $0.73 per mcfe at year-end 2010. We expect to achieve our goal of reducing debt primarily with proceeds from asset monetizations during this two-year period. Among the several benefits of lower debt are lower borrowing costs, and we believe improved credit metrics will lead to more favorable debt ratings by the major ratings agencies over time.

Transform U.S. Transportation Fuels Market and Increase Demand for U.S. Natural Gas. In an effort to decrease U.S. dependence on foreign oil imports and increase demand for U.S. natural gas, in July 2011, we announced our plan to create Chesapeake NG Ventures Corporation (CNGV), which is dedicated to identifying and investing in companies and technologies that have the potential to replace the use of gasoline and diesel derived primarily from imported oil with domestic oil, natural gas and natural gas-to-liquids fuels. We believe this plan, if successful, will benefit our industry and will also lower energy costs to American consumers, enhance national security, stimulate economic growth, create new high-paying jobs and improve the environment. To fund our commitment, we intend to redirect approximately 1 – 2% of our forecasted annual drilling and completion budget away from efforts to increase natural gas supply toward projects that instead are designed to stimulate natural gas

demand. Over a 10-year period, we anticipate investing at least $1.0 billion in CNGV initiatives seeking breakthroughs in scalable, natural gas-focused technologies. To date, we have committed approximately $315 million in total to three separate ventures. In 2011, we agreed to invest $150 million in newly issued convertible promissory notes of Clean Energy Fuels Corp. (Nasdaq:CLNE), based in Seal Beach, California, to help CLNE accelerate the build-out of LNG fueling infrastructure for heavy-duty trucks at truck stops across interstate highways in the U.S. Also in 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Louisville, Colorado to fund construction of a waste biomass-based "green gasoline" plant, capable of annually producing more than 40 million gallons of gasoline from natural gas and cellulosic material. More recently, in 2012, we pledged an initial $10 million towards a collaboration with 3M (NYSE:MMM) to design, manufacture and market a broad portfolio of compressed natural gas tanks for use in all sectors of the U.S. transportation market.

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 15 producer of liquids, the most active driller of new wells in the U.S., a major oilfield services provider, one of the nation's largest midstream and natural gas and liquids marketing companies, an employer of approximately 12,600 people and an indirect employer of tens of thousands more. We take pride in our innovative and aggressive implementation of our business strategy and strive to be as entrepreneurial today as we were when we were a much smaller company. 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. Our efforts in the development of our human resources have been recognized by many, most recently Fortune Magazine, which in January 2012 named Chesapeake the 18th best company to work for in the U.S., including the fifth-best among U.S. companies with more than 10,000 employees and the top-ranked company within the U.S. oil and gas industry.

Operating Divisions

Chesapeake focuses its exploration, development, acquisition and production efforts in four geographic operating divisions described below.

Southern Division. Our Southern division primarily includes the Haynesville and Bossier Shales in northwestern Louisiana and East Texas and the Barnett Shale in the Fort Worth Basin of north-central Texas. Proved reserves in the Southern division were 8.039 tcfe, or 43%, of our total proved reserves by volume as of December 31, 2011. During 2011, the Southern division assets produced 562 bcfe, or 47%, of our total 2011 production, and we invested approximately $2.7 billion to drill 1,104 gross (550 net) wells, net of $417 million in drilling and completion cost carries paid by our Barnett Shale joint venture partner, Total. For 2012, we anticipate spending approximately $700 million, or 10% of our total budget, for exploration and development activities in the Southern division.

Northern Division. Our Northern division includes the Mid-Continent (principally the Anadarko Basin in western Oklahoma and the Texas Panhandle) and, prior to April 2011, the Fayetteville Shale. In March 2011, we sold all of our Fayetteville Shale assets. Proved reserves in the Northern division were 5.416 tcfe, or 29%, of our total proved reserves by volume as of December 31, 2011. During 2011, the Northern division assets produced 383 bcfe, or 32%, of our total 2011 production, and we invested approximately $1.8 billion to drill 1,076 gross (342 net) wells. For 2012, we anticipate spending approximately $2.6 billion, or 36% of our total budget for exploration and development activities in the Northern division, with a continuing focus on the Granite Wash and an increasing focus on the Tonkawa, Cleveland and Mississippi Lime liquids-rich unconventional plays in the Anadarko Basin.

Eastern Division. Our Eastern division primarily includes the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania and the Utica Shale in Ohio and Pennsylvania. Proved reserves in the Eastern division were 3.188 tcfe, or 17%, of our total proved reserves by volume as of December 31, 2011. During 2011, the Eastern division assets produced 145 bcfe, or 12%, of our total 2011 production, and we invested approximately $1.5 billion to drill 371 gross (149 net) wells, net of $1.1 billion in drilling and completion cost carries paid by our Marcellus Shale joint partner, Statoil. For 2012, we anticipate spending approximately $1.2 billion, or 17% of our total budget, net of carries, for exploration and development activities in the Eastern division. Statoil will pay 75% of our drilling and completion costs in the Marcellus Shale until $2.125 billion has been paid. We expect all of the $223 million drilling and completion cost carry remaining in the Marcellus Shale as of December 31, 2011 will be utilized in 2012. Total, our Utica Shale joint venture partner, will pay 60% of our drilling and completion costs in the play until $1.422 billion has been paid, which we expect to occur by year-end 2018. Of the $1.422 billion of drilling and completion cost carry remaining as of December 31, 2011, we expect approximately $350 million will be utilized in 2012.

Western Division. Our Western division primarily includes the Permian and Delaware Basins of West Texas and southern New Mexico, the Eagle Ford Shale in South Texas and the Rocky Mountain/Williston Basin plays, including the Niobrara Shale. Proved reserves in the Western division were 2.146 tcfe, or 11%, of our total proved reserves by volume as of December 31, 2011. During 2011, the Western division assets produced 105 bcfe, or 9%, of our total 2011 production, and we invested approximately $1.7 billion to drill 428 gross (241 net) wells, net of $1.0 billion in drilling and completion cost carries paid by our joint venture partner in the Eagle Ford Shale and the Niobrara Shale, CNOOC. For 2012, we anticipate spending approximately $2.7 billion, or 37% of our total budget, net of carries, for exploration and development activities in the Western division, with an increased focus on the Bone Spring, Avalon, Wolfcamp and Wolfberry liquids-rich unconventional plays located in the Permian and Delaware Basins. CNOOC will pay 75% of our drilling and completion costs in the Eagle Ford Shale until $1.08 billion has been paid. We expect all of the $144 million drilling cost carry remaining in the Eagle Ford Shale as of December 31, 2011 will be utilized in the 2012 first quarter. CNOOC will also pay approximately 67% of our drilling and completion costs in the Niobrara Shale until $697 million has been paid, which we expect to occur by year-end 2014. Of the $570 million of drilling and completion cost carry remaining in the Niobrara Shale, we expect approximately $125 million will be utilized in 2012.

Well Data

At December 31, 2011, we had interests in approximately 45,700 gross (22,000 net) productive wells, including properties in which we held an overriding royalty interest, of which 38,000 gross (19,600 net) were classified as primarily natural gas productive wells and 7,700 gross (2,400 net) were classified as primarily oil productive wells. Chesapeake operates approximately 24,800 of its 45,700 productive wells. During 2011, we drilled 1,628 gross (1,069 net) wells and participated in another 1,351 gross (213 net) wells operated by other companies. We operate approximately 85% of our current daily production volumes.

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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.

	2011				2010				2009			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	2,536	99	1,077	99	2,721	99	1,031	99	1,971	98	875	99
Dry	10	1	3	1	30	1	12	1	33	2	8	1
Total	2,546	100%	1,080	100%	2,751	100%	1,043	100%	2,004	100%	883	100%
Exploratory:												
Productive	430	99	201	99	265	95	99	93	196	97	115	96
Dry	3	1	1	1	15	5	7	7	6	3	5	4
Total	433	100%	202	100%	280	100%	106	100%	202	100%	120	100%

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

	2011		2010		2009	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Southern	1,104	550	1,023	495	795	527
Northern	1,076	342	1,371	369	1,160	353
Eastern	371	149	367	140	158	81
Western	428	241	270	145	93	42
Total	2,979	1,282	3,031	1,149	2,206	1,003

At December 31, 2011, we had 1,282 (537 net) wells in drilling or completing status or waiting on pipe.

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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,		
	2011	2010	2009
Net Production[a]:			
Natural gas (bcf)	1,004.1	924.9	834.8
Oil (mmbbl)[b]	31.7	18.4	11.8
Natural gas equivalent (bcfe)[c]	1,194.2	1,035.2	905.5
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 3,133	$ 3,169	$ 2,635
Natural gas derivatives – realized gains (losses)	1,656	1,982	2,313
Natural gas derivatives – unrealized gains (losses)	(669)	425	(492)
Total natural gas sales	4,120	5,576	4,456
Oil sales[b]	2,126	1,079	656
Oil derivatives – realized gains (losses)	(102)	74	33
Oil derivatives – unrealized gains (losses)	(120)	(1,082)	(96)
Total oil sales	1,904	71	593
Total natural gas and oil sales	$ 6,024	$ 5,647	$ 5,049
Average Sales Price (excluding gains (losses) on derivatives)[a]:			
Natural gas ($ per mcf)	$ 3.12	$ 3.43	$ 3.16
Oil ($ per bbl)[b]	$ 67.11	$ 58.67	$ 55.60
Natural gas equivalent ($ per mcfe)	$ 4.40	$ 4.10	$ 3.63
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 4.77	$ 5.57	$ 5.93
Oil ($ per bbl)[b]	$ 63.90	$ 62.71	$ 58.38
Natural gas equivalent ($ per mcfe)	$ 5.70	$ 6.09	$ 6.22
Other Operating Income[d] ($ per mcfe):			
Marketing, gathering and compression net margin	$ 0.10	$ 0.12	$ 0.16
Oilfield services net margin	$ 0.10	$ 0.03	$ 0.01
Expenses ($ per mcfe):			
Production expenses[a]	$ 0.90	$ 0.86	$ 0.97
Production taxes	$ 0.16	$ 0.15	$ 0.12
General and administrative expenses	$ 0.46	$ 0.44	$ 0.38
Natural gas and oil depreciation, depletion and amortization	$ 1.37	$ 1.35	$ 1.51
Depreciation and amortization of other assets	$ 0.24	$ 0.21	$ 0.27
Interest expense[e]	$ 0.03	$ 0.08	$ 0.22

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

(b) Includes natural gas liquids (NGLs).

(c) Natural gas equivalent is based on six mcf of natural gas to one barrel of oil. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given recent commodity prices, the price for an mcfe of natural gas is significantly less than the price for an mcfe of oil or NGLs.

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

(e) 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.

Natural Gas and Oil Reserves

The tables below set forth information as of December 31, 2011 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 U.S.

	December 31, 2011		
	Natural Gas (bcf)	Oil (mmbbl)[a]	Total (bcfe)[b]
Proved developed	8,578	254.6	10,106
Proved undeveloped	6,937	290.9	8,683
Total proved[c]	15,515	545.5	18,789

	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue[d]	$ 27,895	$ 20,149	$ 48,044
Present value of estimated future net revenue[d]	$ 14,039	$ 5,839	$ 19,878
Standardized measure[d][e]			$ 15,630

	Natural Gas (bcf)	Oil (mmbbl)[a]	Natural Gas Equivalent (bcfe)[b]	Percent of Proved Reserves	Present Value ($ millions)
Southern	7,928	18.3	8,039	43%	$ 3,898
Northern	3,510	317.7	5,416	29	8,568
Eastern	3,053	22.5	3,188	17	3,669
Western	1,024	187.0	2,146	11	3,743
Total	15,515	545.5	18,789	100%	$ 19,878[d]

(a) Includes NGLs.

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

(c) Includes 130 bcf of natural gas and 18.9 mmbbls oil reserves owned by the Chesapeake Granite Wash Trust, 64 bcf and 9.3 mmbbls of which are attributable to the noncontrolling interest holders.

(d) 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 as of December 31, 2011. 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, 2011. The prices used in our reserve reports were $4.12 per mcf of natural gas and $95.97 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 derivative instruments in place as of December 31, 2011. 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 ($4.2 billion as of December 31, 2011).

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.

(e) 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.

As of December 31, 2011, our reserve estimates included 8.683 tcfe of reserves classified as proved undeveloped (PUD), compared to 7.953 tcfe as of December 31, 2010. Presented below is a summary of changes in our proved undeveloped reserves for 2011.

	Total (bcfe)
Proved undeveloped reserves, beginning of period	7,953
Extensions, discoveries and other additions	3,564
Revisions of previous estimates	(397)
Developed	(1,076)
Sale of reserves-in-place	(1,375)
Purchase of reserves-in-place	14
Proved undeveloped reserves, end of period	8,683

As of December 31, 2011, there were no PUDs that had remained undeveloped for five years or more. We invested approximately $1.477 billion, net of drilling and completion cost carries, in 2011 to convert 1.076 tcfe of PUDs to proved developed reserves. In 2012, we estimate that we will invest approximately $2.3 billion, net of drilling and completion cost carries, for PUD conversion.

The future net revenue attributable to our estimated proved undeveloped reserves of $20.149 billion at December 31, 2011, and the $5.839 billion present value thereof, has been calculated assuming that we will expend approximately $13.6 billion to develop these reserves: $2.3 billion in 2012, $2.5 billion in 2013, $3.3 billion in 2014 and $5.5 billion in 2015 and beyond, although the amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, commodity 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.

Our proved reserves as of December 31, 2011 included PUDs more than directly offsetting producing wells in three resource plays: the Barnett Shale, the Haynesville Shale and the Marcellus Shale. In all other areas, we restricted PUD locations to immediate offsets to producing wells. Within the Barnett, Haynesville and Marcellus 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 (collected both vertically and horizontally) 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 in 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 32% from 2012 to 2013, 20% from 2013 to 2014, 16% from 2014 to 2015, 13% from 2015 to 2016 and 11% from 2016 to 2017. Of our 10.106 tcfe of proved developed reserves as of December 31, 2011, 1.139 tcfe 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, 2011. The estimated proved reserves may not 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, 2011, 2010 and 2009, and the changes in quantities and standardized measure of such reserves for each of the three years then ended, are shown in Note 10 of the notes to the consolidated financial statements included in Item 8 of this report. 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 our 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.

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 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 2011 12-month average prices of $4.12 per mcf and $95.97 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, 2011, which were $4.92 per mcf and $92.61 per barrel, before price differential adjustments. Our cost and other assumptions are the same under the two pricing scenarios.

	December 31, 2011			
	Gas (bcf)	Oil (mmbbl)[a]	Total (bcfe)	Present Value ($ in millions)
2011 12-month average prices (SEC)[b]	15,515	545.5	18,789	$ 19,878
10-year average future NYMEX strip prices as of December 31, 2011[c]	16,579	551.3	19,887	$ 23,844

(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.

Reserves Estimation

Chesapeake's Reservoir Engineering Department prepared approximately 23% (compared to 22% in 2010) 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 116 full-time employees, consisting of 69 degreed engineers (ten serving in management capacities), 45 engineering technicians with a minimum of a four-year degree in mathematics, economics, finance or other business/ science field, and two administrative persons. Twelve of our engineers are registered professional engineers with various state board certifications. The department collectively has approximately 1,700 years of 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.

We maintain internal controls such as the following to ensure the reliability of reserves estimations:

- 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 of the Company's reported proved reserves at the close of each quarter.

- Each quarter, Reservoir Engineering Department managers, the Vice President of Corporate Reserves, 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 Corporate Reserves is the technical person primarily responsible for overseeing the preparation of the Company's reserve estimates. His qualifications include the following:

- 36 years of practical experience in petroleum engineering with 33 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 77% of our estimated proved reserves (by volume) at year-end 2011. The portion of our estimated proved reserves prepared by each of our third-party engineering firms as of December 31, 2011 is presented below.

	% Prepared (by Volume)	Principal Properties
Netherland, Sewell & Associates, Inc.	42%	Northern, Southern, Western
Ryder Scott Company, L.P.	19%	Northern
Lee Keeling and Associates, Inc.	9%	Northern, Southern, Western
Data & Consulting Services, Division of Schlumberger Technology Corporation	7%	Eastern

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 29 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

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

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 & 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

Drilling and Completion, Acquisition and Divestiture Activities

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

	December 31,		
	2011	2010	2009
		($ in millions)	
Drilling and completion costs:			
Development[a]	$ 5,495	$ 4,739	$ 2,729
Exploratory[b][c]	2,260	872	813
Asset retirement obligation and other	3	2	(2)
	7,758	5,613	3,540
Acquisition costs:			
Unproved properties[d]	4,736	6,953	2,793
Proved properties	48	243	61
	4,784	7,196	2,854
Proceeds from divestitures:			
Unproved properties	(4,943)	(1,524)	(1,265)
Proved properties	(2,612)	(2,876)	(461)
	(7,555)	(4,400)	(1,726)
Total	$ 4,987	$ 8,409	$ 4,668

(a) Includes capitalized internal costs of $399 million, $353 million and $337 million, respectively.

(b) Includes capitalized internal costs of $18 million, $16 million and $22 million, respectively.

(c) Includes related capitalized interest of $18 million, $24 million and $29 million, respectively.

(d) Includes related capitalized interest of $709 million, $687 million and $598 million, respectively.

Our development costs included $1.477 billion, $789 million and $621 million in 2011, 2010 and 2009, respectively, related to properties carried as proved undeveloped locations in the prior year's reserve reports.

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A summary of our drilling and completion, acquisition and divestiture activities in 2011 by operating division is as follows:

	Gross Wells Drilled	Net Wells Drilled	Drilling and Completion[a]	Acquisition of Unproved Properties[b]	Acquisition of Proved Properties	Sales of Unproved Properties	Sales of Proved Properties	Total
			($ in millions)					
Southern	1,104	550	$ 2,722	$ 740	$ 12	$ (515)	$ (56)	$ 2,903
Northern	1,076	342	1,791	1,280	16	(2,577)	(2,488)	(1,978)
Eastern	371	149	1,515	1,523	20	(979)	(50)	2,029
Western	428	241	1,730	1,193	—	(872)	(18)	2,033
Total	2,979	1,282	$ 7,758	$ 4,736	$ 48	$ (4,943)	$ (2,612)	$ 4,987

(a) Includes capitalized internal costs of $417 million and related capitalized interest of $18 million.

(b) Includes related capitalized interest of $709 million.

Acreage

The following table sets forth as of December 31, 2011 the gross and net developed and undeveloped natural gas and oil leasehold and fee mineral acreage. "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 Leasehold		Undeveloped Leasehold		Fee Minerals		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
				(in thousands)				
Southern	1,009	654	481	270	136	64	1,626	988
Northern	4,583	2,333	4,176	2,726	667	184	9,426	5,243
Eastern	1,982	1,534	6,380	3,690	683	523	9,045	5,747
Western	903	499	5,419	2,759	239	23	6,561	3,281
Total	8,477	5,020	16,456	9,445	1,725	794	26,658	15,259

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.

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The following table sets forth as of December 31, 2011, the expiration periods of gross and net undeveloped leasehold acres, unless production from the leasehold acreage is established prior to the expiration date, or we take action to extend the lease term.

	Acres Expiring[a]	
	Gross Acres	Net Acres
	(in thousands)	
Years Ending December 31:		
2012	2,075	1,081
2013	3,486	1,980
2014	3,327	2,212
After 2014 and other[b]	7,568	4,172
Total	16,456	9,445

(a) We maintain a very large drilling program that is rigorously scheduled to lock in our acreage with the highest prospective value. Our control of a substantial rig fleet and other oilfield services assets 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.

(b) Includes held-by-production acreage that will remain in force as production continues on the subject leases, and other leasehold acreage where management anticipates the lease to remain in effect past the primary term of the agreement due to our contractual right to extend the lease term.

Marketing, Gathering and Compression

Marketing

Chesapeake Energy Marketing, Inc. (CEMI), 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 joint working interest owners 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 2012, 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 2011.

Our marketing activities, along with our midstream gathering and compression operations described below, constitute a reportable segment under accounting guidance for disclosure about segments of an enterprise and related information. See Note 17 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 joint working interest owners and other 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. The CMD systems are located in Oklahoma, Texas, New Mexico, New York, Ohio, Louisiana, Pennsylvania, Wyoming and West Virginia and consist of approximately 1,950 miles of gathering pipelines, servicing over 1,900 natural gas wells. The majority of the CMD systems are in developing areas and will require significant build-out capital expenditures. A source of liquidity for CMD's business is the $600 million revolving bank credit facility described under *Liquidity and Capital Resources* in Item 7 below.

We also invest in midstream operations through our affiliate, Chesapeake Midstream Partners, L.P. (CHKM), a master limited partnership which we and Global Infrastructure Partners-A, L.P. and affiliated funds managed by Global Infrastructure Management, LLC and certain of their respective subsidiaries and affiliates (collectively, GIP) formed in 2010 to own, operate, develop and acquire gathering systems and other midstream energy assets. As of December 31, 2011, public security holders, GIP and Chesapeake owned 23.5%, 30.4% and 46.1%, respectively, of all outstanding CHKM limited partner interests. CHKM 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. CHKM common units representing limited partner interests trade on the New York Stock Exchange. CHKM is principally focused on natural gas gathering, the first segment of midstream energy infrastructure that connects natural gas produced at the wellhead to third-party takeaway pipelines. CHKM currently operates in Texas, Louisiana, Oklahoma, Kansas, Arkansas, Pennsylvania and West Virginia and provides gathering, treating and compression services to Chesapeake and other leading producers under long-term, fixed-fee contracts.

CHKM completed its initial public offering of common units on August 3, 2010 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 granted to the underwriters of the offering. Prior to the initial public offering, in September 2009, we and GIP formed a joint venture to own and operate natural gas midstream assets. As part of the transaction, CMD contributed certain natural gas gathering systems to the newly formed joint venture entity, and GIP purchased a 50% interest 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. Chesapeake and GIP contributed the interests of the midstream joint venture's operating subsidiary to CHKM in connection with the closing of CHKM's initial public offering.

CHKM has significant potential long-term growth opportunities, including through its rights of first offer on certain future CMD midstream divestitures as well as through the development and acquisition of additional midstream assets adjacent to our existing areas of operation. In December 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 gas gathering and compression agreements covering Chesapeake's and other producers' 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 put in place upon the closing of the CHKM initial public offering and include a minimum volume commitment and periodic rate redetermination.

In December 2011, CMD sold its wholly owned subsidiary, Appalachia Midstream Services, L.L.C. (AMS), which held certain of our Marcellus Shale midstream assets, to CHKM for total consideration of $879 million. We and other producers in the area have entered into 15-year fixed fee gathering agreements that include significant acreage dedications and annual fee redeterminations. In addition, CMD has committed to pay CHKM quarterly any shortfall between the actual EBITDA from these assets and specified quarterly targets, which targets total $100 million in 2012 and $150 million in 2013. See Note 11 of the notes to our consolidated financial statements in Item 8 for further discussion.

As of December 31, 2011, CHKM's systems consisted of approximately 3,630 miles of gathering pipelines, servicing approximately 4,965 natural gas wells and gathering approximately 2.2 bcf of natural gas per day.

Compression

Since 2003, Chesapeake has expanded its compression business. Our wholly owned subsidiary, MidCon Compression, L.L.C. (MidCon), operates wellhead and system compressors, with over 1.0 million horsepower of compression, to facilitate the transportation of natural gas primarily produced from Chesapeake-operated wells. In a series of transactions since 2007, MidCon sold 2,542 compressors (net of six repurchased units), a significant portion of its compressor fleet, for $635 million and entered into a master lease agreement. These transactions were recorded as sales and operating leasebacks.

Oilfield Services

We formed Chesapeake Oilfield Services, L.L.C. (COS) in 2011 to own and operate our oilfield services assets. COS is a diversified oilfield services company that provides a wide range of well site services, primarily to Chesapeake and its working interest partners. COS focuses on providing services that we have identified as scarce or as having relatively high margins. These services include contract drilling, pressure pumping, tool rental, transportation and manufacturing of natural gas compressor packages and related production equipment. These services are fundamental to establishing and maintaining the flow of natural gas and oil throughout the productive life of a well. A source of liquidity for COS's business is the $500 million revolving bank credit facility described under *Liquidity and Capital Resources* in Item 7 of this report. Additionally, in October 2011, Chesapeake Oilfield Operating, L.L.C. (COO), a wholly owned subsidiary of COS, issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. Proceeds from this placement were used to make a cash distribution to its direct parent, COS, to enable it to reduce indebtedness under an intercompany note with Chesapeake.

Our oilfield services operations constitute a reportable segment under accounting guidance for disclosure about segments of an enterprise and related information. See Note 17 of the notes to our consolidated financial statements in Item 8 of this report. COS conducts operations through five lines of business, as described below.

Contract Drilling

Securing available rigs is an integral part of the exploration process and therefore owning our own drilling company is a strategic advantage for us. In 2001, we formed our wholly owned drilling subsidiary, Nomac Drilling, L.L.C., with an investment of $26 million to build and refurbish five drilling rigs. As of December 31, 2011, we had invested approximately $1.5 billion to build or acquire 132 drilling rigs, which are utilized primarily to drill Chesapeake-operated wells. In a series of transactions since 2006, our drilling subsidiaries sold 93 drilling rigs (net of one repurchased rig) and related equipment for $802 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, Louisiana, West Virginia, Pennsylvania, Ohio and North Dakota. As of December 31, 2011, we had a fleet of 39 owned and 93 leased land drilling rigs, 114 of which we were operating, making us the fourth largest land driller operating in the U.S.

Pressure Pumping

In 2010, we began the process of building a pressure pumping business under the name of Performance Technologies, L.L.C. (PTL). As part of that effort, we purchased two hydraulic fracturing fleets with an aggregate of 60,000 horsepower, one of which was deployed in the 2011 fourth quarter and the other in the 2012 first quarter. We use our pressure pumping assets to provide hydraulic fracturing and other well stimulation services. We plan to have nine fleets with an aggregate of approximately 340,000 horsepower operating by the first quarter of 2013 and plan to build PTL into one of the nation's five largest pressure pumping companies.

Oilfield Rentals

Our oilfield rentals segment provides premium rental tools for land oil and natural gas drilling and workover activities under the name Great Plains Oilfield Rental, L.L.C. We offer our customers a number of products and services, including drill pipe, drill collars, tubing, high and low pressure blowout preventers, water transfer, frac tanks, mud tanks and mud systems. As of December 31, 2011, we owned 2,074 frac tanks and 1.5 million feet of drill pipe.

Oilfield Trucking

In 2006, we expanded our oilfield services 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 under the names of Hodges Trucking, L.L.C. and Oilfield Trucking Solutions, L.L.C. Our trucking business provides rig relocation and logistics services as well as fluid hauling services. Our trucks move drilling rigs, water, crude oil, other fluids and construction materials. As of December 31, 2011, we owned a fleet of 202 rig relocation trucks, 56 cranes and forklifts used in the movement of drilling rigs and other heavy equipment and 127 fluid service trucks.

Compressor Manufacturing

Our compressor manufacturing business operates under the name of Compass Manufacturing, L.L.C. and consists of natural gas compressor manufacturing operations in which we design, engineer, fabricate, install and sell natural gas compression units, accessories and equipment used in the production, treatment and processing of natural gas and oil. Once the compressors are complete, they are sold to MidCon and put into service for Chesapeake-operated wells.

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. 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 U.S. 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 administrative, civil and criminal penalties for non-compliance. Although we believe we are in substantial compliance with all applicable laws and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations, such laws and regulations could be, and frequently are, amended or reinterpreted. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance or non-compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the courts and federal agencies, such as the U.S. Environmental Protection Agency (EPA), the Federal Energy Regulatory Commission, the Department of Transportation, the Department of Interior and the Department of Energy. We actively monitor regulatory developments regarding our industry in order to anticipate and design required compliance activities and systems.

Exploration and Production Operations

The laws and regulations applicable to our exploration and production operations include 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 such laws and regulations 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;
- water withdrawal;
- 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 may require us to obtain permits for, among other things,

- air emissions;
- construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- 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.

Delays in obtaining permits or an inability to obtain new permits or permit renewals could inhibit our ability to execute our drilling and production plans. Failure to comply with provisions of our permits could result in revocation of such permits and the imposition of fines and penalties.

Our exploration and production activities 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 Pennsylvania, 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 or controls less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amount of natural gas and oil we can produce and to limit the number of wells and the locations at which we can drill.

Midstream Operations

In addition to the environmental, health and safety laws and regulations discussed below under *Environmental, Health and Safety Matters*, our midstream facilities are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation (DOT) pursuant to the Natural Gas Pipeline Safety Act of 1968 (NGPSA) and the Pipeline Safety Improvement Act of 2002 (PSIA) which was reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transportation pipelines and some gathering lines in high-consequence areas. The PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in "high consequence areas," such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways.

We or the entities in which we own an interest inspect our pipelines regularly using equipment rented from third-party suppliers. Third parties also assist us in interpreting the results of the inspections.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. Our natural gas pipelines have inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

Natural gas gathering and intrastate transportation facilities are exempt from the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act. Although FERC has not made any formal determinations with regard to any of our facilities, we believe that our natural gas pipelines and related facilities are engaged in exempt gathering and intrastate transportation and, therefore, are not subject to FERC jurisdiction.

FERC regulation affects our gathering and compression business generally. FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on

open access transportation, market manipulation, ratemaking, capacity release and market transparency and market center promotion, indirectly affect our gathering business. In addition, the distinction between FERC-regulated transmission facilities and federally unregulated gathering and intrastate transportation facilities is a fact-based determination made by FERC on a case by case basis; this distinction has also been the subject of regular litigation and change. The classification and regulation of our gathering and intrastate transportation facilities are subject to change based on future determinations by FERC, the courts or Congress.

Our natural gas gathering operations are subject to ratable take and common purchaser statutes in most of the states in which we operate. These statutes generally require our gathering pipelines to take natural gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate have adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination.

Oilfield Services Operations

Our oilfield services business operates under the jurisdiction of a number of regulatory bodies that regulate worker safety standards, the handling of hazardous materials, the transportation of explosives, the protection of the environment and driving standards of operation. Regulations concerning equipment certification create an ongoing need for regular maintenance that is incorporated into our daily operating procedures.

In providing trucking services, we operate as a motor carrier and therefore are subject to regulation by the DOT and various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations and regulatory safety, financial reporting and certain mergers, consolidations and acquisitions. Interstate motor carrier operations are subject to safety requirements prescribed by the DOT and, to a large degree, intrastate motor carrier operations are subject to safety regulations that mirror federal regulations. Such matters as weight and dimension of equipment are also subject to federal and state regulations, and DOT regulations mandate drug testing of drivers. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements.

The trucking industry is subject to possible regulatory and legislative changes that may affect the economics of the industry by requiring changes in operating practices or by changing the demand for common or contract carrier services or the cost of providing truckload services. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service regulations that govern the amount of time a driver may drive in any specific period, onboard black box recorder devices or limits on vehicle weight and size.

Environmental, Health and Safety Matters

Our operations are subject to stringent and complex federal, state and local laws and regulations relating to the protection of human health and safety, the environment and natural resources. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;

- requiring investigatory and remedial actions to limit pollution conditions caused by our operations or attributable to former operations; and
- prohibiting the operations of facilities deemed to be in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial or restoration obligations, and the issuance of orders enjoining future operations or imposing additional compliance requirements. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in substantial compliance with changing environmental laws and regulations and to reduce the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations and that share best practices and lessons learned.

Below is a discussion of the material environmental, health and safety laws and regulations that relate to our business. We believe that we are in substantial compliance with these laws and regulations. We do not believe that compliance with existing environmental, health and safety laws or regulations will have a material adverse effect on our financial condition, results of operations or cash flow. At this point, however, we cannot reasonably predict what applicable laws, regulations or guidance may eventually be adopted with respect to our operations or the ultimate cost to comply with such requirements.

Hazardous Substances and Waste

Federal and state laws, in particular the Federal Resource Conservation and Recovery Act, or RCRA, regulate hazardous and non-hazardous solid wastes. In the course of our operations, we generate petroleum hydrocarbon wastes such as produced water and ordinary industrial wastes. Under a longstanding legal framework, certain of these wastes are not subject to federal regulations governing hazardous wastes, although they are regulated under other federal and state laws.

Federal, state and local laws may also require us to remove or remediate previously disposed wastes or hazardous substances otherwise released into the environment, including wastes or hazardous substances 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 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.

Air Emissions

Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations, and impose various monitoring and reporting requirements. The EPA has published proposed New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that, if adopted as proposed, would amend existing NSPS and NESHAP standards for oil and gas facilities as well as create new NSPS standards for oil and gas production, transmission and distribution facilities.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. The placement of material into jurisdictional water or wetlands of the U.S. is prohibited, except in accordance with the terms of a permit issued by the United States Army Corps of Engineers. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or a state agency delegated with EPA's authority. Further, Chesapeake's corporate policy prohibits discharge of produced water to surface waters. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

The Oil Pollution Act of 1990, or OPA, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S.

Hydraulic Fracturing

Vast quantities of natural gas, natural gas liquids and oil deposits exist in deep shale and other unconventional formations. It is customary in our industry to recover these resources from these deep formations through the use of hydraulic fracturing, combined with horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in deep underground formations using water, sand and other additives pumped under high pressure into the formation. As with the rest of the industry, we use hydraulic fracturing as a means to increase the productivity of almost every well that we drill and complete. These formations are generally geologically separated and isolated from fresh ground water supplies by thousands of feet of impermeable rock layers.

We follow applicable legal requirements for groundwater protection in our operations that are subject to supervision by state and federal regulators (including the Bureau of Land Management on federal acreage). Furthermore, 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.

Injection rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations are shut down immediately if an abrupt change occurs to the injection pressure or annular pressure. These aspects of well construction are designed to eliminate a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations.

Hydraulic fracture stimulation requires the use of water. We use fresh water in our fracturing treatments in accordance with applicable water management plans and laws. We strive to find alternative sources of water and minimize our reliance on fresh water resources. We have technical staff dedicated to the development of water recycling and re-use systems, and our Aqua Renew® program uses state-of-the-art technology in an effort to recycle produced water in our operations.

Produced, or formation, water is a naturally occurring by-product of natural gas and liquids extraction. Chesapeake disposes of produced formation water in Class II underground injection control wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. These Class II wells are overseen by the EPA in its Underground Injection Control Program.

Some states have adopted, and other states are considering adopting, regulations that impose disclosure requirements on hydraulic fracturing operations. Since early 2011, we have voluntarily participated in FracFocus, a national publicly accessible web-based registry developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission, with support of the U.S. Department of Energy, to report on a well-by-well basis the additives and chemicals and amount of water used in the hydraulic fracturing process for each of the wells we operate. The website, www.fracfocus.org, also includes information about how hydraulic fracturing works, the chemicals used in hydraulic fracturing and how fresh water aquifers are protected. Some states, such as Texas, Colorado, Montana, Louisiana and North Dakota, which mandate disclosure of chemical additives used in hydraulic fracturing require operators to use the FracFocus website for reporting.

Legislative, regulatory and enforcement efforts, as well as guidance from regulatory agencies, at the federal level and in some states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Hydraulic fracturing is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the Safe Drinking Water Act's Underground Injection Control Program and has begun the process of drafting guidance documents for permitting authorities and the industry on the process for obtaining a permit for hydraulic fracturing involving diesel fuel. While we believe such permitting would not materially affect our operations because we do not use diesel fuel in connection with our hydraulic fracturing, industry groups have filed suit challenging the EPA's assertion of authority as improper rule making. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial study results anticipated to be available by late 2012. The results of EPA's guidance, including its definition of diesel fuel, the related litigation, EPA's study, and other analyses by federal and state agencies to assess the impacts of hydraulic fracturing could each spur further action toward federal legislation and regulation of hydraulic fracturing activities. Also, for the second consecutive session, legislation has been introduced in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process.

Restrictions on hydraulic fracturing could make it prohibitive to conduct our operations, and also reduce the amount of oil, natural gas liquids and natural gas that we are ultimately able to produce in commercial quantities from our properties. For further discussion, see Item *1A. Risk Factors – Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays*.

Endangered Species

The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial

compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Global Warming and Climate Change

Various state governments and regional organizations 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. 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.

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 $425 million comprehensive general liability umbrella policy and a $150 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 or may not be commercially available for purchase in the future.

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 approximately 110 cities or towns in the areas where we conduct our operations.

Employees

Chesapeake had approximately 12,600 employees as of December 31, 2011.

Glossary of Natural Gas and Oil Terms

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

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent.

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.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

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.

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

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 (NGLs). 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 (i) the area indentified by drilling and limited by fluid contacts, if any, and (ii) 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 (i) 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 (ii) 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 included in Item 8 of this report. 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.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

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% annual discount rate.

Tbtu. One trillion British thermal units.

Tcf. One trillion cubic feet.

Tcfe. One trillion cubic feet of natural gas equivalent.

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

Undeveloped Acreage. 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, natural gas liquids and oil, 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 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. Record-high supplies of natural gas and weak demand during one of the mildest winters on record in the U.S. have resulted in gas prices at 10-year lows in early 2012.

Further, the prices of natural gas and oil have not moved in tandem in recent years, creating a value gap that has caused us to shift our focus from dry gas plays to liquids-rich plays. While we anticipate that more than 50% of our 2012 revenue will come from our oil and natural gas liquids production, based on current NYMEX strip prices and our current hedging positions, approximately

83% of our estimated reserves at December 31, 2011 were natural gas reserves. A substantial or extended decline in natural gas or oil prices could negatively affect the quantities of natural gas and oil reserves that may be economically produced.

We have historically hedged significant amounts of our anticipated production in order to mitigate a portion of our exposure to adverse market changes in natural gas and oil prices. While portions of our anticipated oil production are hedged through swaps and written call options, we currently have no natural gas price swaps that cover natural gas production. Our natural gas derivatives consist of written call options and basis protection swaps and cover only a small portion of our expected 2012 and 2013 natural gas production. As a consequence, our revenues and results of operations will be more significantly exposed to changes in commodity prices than in historical periods.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2011, we had long-term indebtedness of approximately $10.626 billion and unrestricted cash of $351 million, and our net indebtedness represented 38% of our total book capitalization, which we define as the sum of total Chesapeake stockholders' equity and total current and long-term debt less unrestricted cash. We had $1.749 billion of outstanding borrowings drawn under our revolving bank credit facilities at December 31, 2011.

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, the oilfield services revolving bank credit facility and the indenture governing the COO 6.625% Senior Notes due 2019 restrict 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 of 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.

We recently announced an update to our operations and capital spending program in 2012, including our previously announced 25/25 Plan, pursuant to which we intend to engage in certain monetization transactions and apply a portion of the net proceeds to reduce our overall level of indebtedness. If we are unable to consummate such contemplated monetization transactions or if such transactions do not generate the proceeds we are anticipating, we would be required to reduce our capital spending, seek to identify, pursue and obtain funds from other monetization transactions or other sources in order to meet our operating, capital spending and debt reduction plans.

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. Natural gas prices declined significantly in late 2011 and early 2012 to the lowest level in recent years and continue to trade near historic lows. Although we did not have an impairment of our natural gas and oil properties as of December 31, 2011, sustained low natural gas prices and other factors could cause us to be required to write down our natural gas and oil properties or other assets in the future and incur a non-cash charge against future earnings.

Significant capital expenditures are required to replace our reserves and conduct our business.

Our exploration, development and acquisition activities and our midstream and oilfield services businesses require substantial capital expenditures. We fund our capital expenditures through a combination of cash flows from operations and borrowings under our corporate, midstream and oilfield services revolving bank credit facilities and, to the extent those sources are not sufficient, from debt and equity issuances, subsidiary-level financings and asset monetizations. Future cash flows from operations are subject to a number of risks and variables, such as the level of production from existing wells, prices of natural gas and oil, our success in developing and producing new reserves and the other risk factors discussed herein. Our ability to obtain capital from other sources, such as the capital markets, subsidiary-level financing and asset monetizations, is dependent upon many of those same factors as well as the orderly functioning of credit and capital markets. We plan to make capital

expenditures in 2012 that exceed our estimated 2012 cash flows from operations, and we anticipate funding this difference with the proceeds from transactions such as joint ventures, volumetric production payments, financial transactions, property and investment dispositions and other asset monetizations. To the extent that proceeds from these potential transactions are inadequate to fund our planned spending, we would be required to reduce our capital spending, seek to monetize different or additional assets or pursue other funding alternatives, and we would have a reduced ability to replace our reserves.

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 46% of our total estimated proved reserves (by volume) at December 31, 2011 were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates at December 31, 2011 reflected a decline in the production rate on producing properties of approximately 32% in 2012 and 20% in 2013. 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 be different 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 and involves significant decisions and assumptions associated with geological, geophysical, engineering and economic data for each well. Therefore, these estimates are subject to future revisions.

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.

At December 31, 2011, approximately 46% 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 (PUDS) into proved developed reserves, including approximately $13.6 billion during the five years ending in 2016. 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, 2011 present value is based on $4.12 per mcf of natural gas and $95.97 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 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, state or local bans or moratoriums on hydraulic fracturing 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 oilfield services 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 liquids 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 production, 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 hedging 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 18 counterparties to 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 hedging 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. Some of these risks or hazards

could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, loss of equipment 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 use, generation, handling and disposal of materials, including wastes, petroleum hydrocarbons and other chemicals. 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 resulting from current or historical operations. In some cases our properties 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. We also could incur material fines, penalties and government or third-party claims as a result of violations of, or liabilities under, applicable environmental laws and regulations. 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.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

It is customary in our industry to recover natural gas and oil from deep shale and other formations through the use of horizontal drilling combined with hydraulic fracturing. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in deep formations using water, sand and other additives pumped under high pressure into the formation. We use hydraulic fracturing as a means to increase the productivity of almost every well that we drill and complete.

The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Several states, including Pennsylvania, Texas, Colorado, Montana, New Mexico and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and/or well construction requirements on hydraulic fracturing operations. New York has sought to ban fracturing activities altogether. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

Additionally, the EPA has asserted federal regulatory authority over hydraulic fracturing activities involving diesel fuel (specifically, when diesel fuel is utilized in the stimulation fluid) under the Safe Drinking Water Act and is completing the process of drafting guidance documents related to this newly asserted regulatory authority. There are also certain governmental reviews either underway or being

proposed that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate such activities. The EPA has published proposed New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that, if adopted as proposed, would amend existing NSPS and NESHAP standards for oil and gas facilities as well as create new NSPS standards for oil and gas production, transmission and distribution facilities. The EPA has also proposed regulations focused on reducing emissions of certain air pollutants by the oil and gas industry, including volatile organic compounds, sulfur dioxide and certain air toxics.

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 additional federal, state or local laws or regulations will be enacted in the future 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.

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 U.S. 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 Independent Producers

Recent federal budget proposals would potentially increase and accelerate the payment of federal income taxes of independent producers of natural gas and oil. Proposals that would significantly affect us would repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase 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.

OTC Derivatives Regulation

In July of 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 and the market-making activities of our customary counterparties 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.

Climate Change

Various state governments and regional organizations 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. 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. Even without federal legislation or regulation of greenhouse gas emissions, states may pursue the issue either directly or indirectly. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and gas industry. 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 U.S. 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 U.S. or abroad deteriorates further, demand for petroleum products could continue to decline, prices for natural gas could continue to decrease and oil and natural gas liquids could become subject to increased downward price pressure. These circumstances 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;
- the collectability of our trade receivables 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 joint venture partners to meet their obligations to fund a portion of our drilling costs under our joint venture 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, an action we took in early 2012. 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. On September 2, 2010, the court denied the defendants' motion to dismiss, and on August 1, 2011, the plaintiffs filed a motion for class certification. Discovery in the case is proceeding. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against certain current and former directors and officers of the Company asserting breaches of fiduciary duties relating to alleged material omissions in the registration statement for the July 2008 offering. The derivative action is stayed pursuant to stipulation. A second derivative action relating to the July 2008 offering was filed against certain current and former directors and officers of the Company in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. This action also asserts breaches of fiduciary duties with respect to alleged material omissions in the offering registration statement. The Company filed a motion to dismiss the action on November 30, 2011, and plaintiffs filed an Opposition on January 9, 2012. Chesapeake is named as a nominal defendant in both derivative actions.

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, among other things, breaches of fiduciary duties relating to the 2008 compensation of the Company's CEO, Aubrey K. McClendon, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition naming Chesapeake as a nominal defendant was filed on June 23, 2009. Chesapeake's motion to dismiss was granted on February 26, 2010, and the Oklahoma Court of Civil Appeals affirmed the dismissal on August 26, 2011. The plaintiffs filed a petition for writ of certiorari with the Oklahoma Supreme Court on September 13, 2011.

On January 30, 2012, the District Court of Oklahoma County, Oklahoma approved the settlement between the parties in the consolidated derivative action, as well as a case on appeal at the Oklahoma Court of Civil Appeals requesting inspection of Company books and records relating to the December 2008 employment agreement with its CEO. The principal terms of the settlement include the rescission of the sale of an antique map collection that occurred in December 2008 between Mr. McClendon and the Company, whereby Mr. McClendon will pay the Company $12.1 million plus interest and the Company will reconvey the map collection to Mr. McClendon, and the adoption and/or implementation of a variety of corporate governance measures. The court awarded attorney fees and expenses to plaintiffs' counsel in the amount of $3,750,000, to be paid by Chesapeake and/or its insurers. Pursuant to the settlement, the consolidated derivative action and books and records action were dismissed with prejudice against all defendants.

On September 6 and 8, 2011, in separate derivative actions filed in the U.S. District Court for the Western District of Oklahoma against certain of the Company's current and former directors, two shareholders alleged that the Chesapeake board wrongfully refused their demands to investigate purported breaches of fiduciary duties relating to Mr. McClendon's 2008 compensation and, as a result, each of these shareholders asserts he is entitled to seek relief on behalf of the Company. These federal derivative actions were consolidated on December 23, 2011 and were stayed pending final approval of the state court settlement. On February 7, 2012, the Court entered an order deferring defendants' response to the complaint until March 6, 2012.

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, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their natural gas and oil 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 has successfully defended a number of these cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal.

The Company records an associated liability when a loss is probable and the amount is reasonably estimable. Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute incidental to the Company's business operations is likely to have a material adverse effect on its 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.

Environmental Proceedings

The Pennsylvania Department of Environmental Protection (DEP) issued a notice of violation following a well control incident in Bradford County, Pennsylvania on April 19, 2011. Chesapeake took several actions in response to the incident, including voluntarily suspending well completion operations in the state and conducting wellhead inspections on other wells in the completion phase in the

Marcellus Shale. With the concurrence of the DEP, we resumed well completion operations in mid-May 2011, and we implemented responsive measures to address issues identified in investigations of the incident conducted by us and the DEP. Our investigation found that, while a small amount of well fluid and rain water was released from the containment area of the well location, the impact to the environment from this release was minimal and localized. An independent consulting firm retained by Chesapeake filed multiple reports with the DEP concluding that there were no ecological impacts to nearby tributaries, no impacts to nearby or regional water wells or springs and no subsurface release of fluids or natural gas from the well control incident. Under a Consent Order and Agreement (COA) dated February 3, 2012 between Chesapeake and the DEP, in settlement of the DEP's claim for civil penalties relating to the incident, Chesapeake paid $123,000 in civil penalties assessed under the Pennsylvania Oil and Gas Act and the Clean Streams Law and agreed to conduct additional shallow groundwater sampling at five monitoring wells surrounding the well site over the course of a year, the last sampling to occur in the spring of 2012. In addition, Chesapeake reimbursed the DEP for costs and expenses associated with the DEP's response to the well control incident in the amount of $67,000.

Under a COA also dated February 3, 2012 between Chesapeake and the DEP, in settlement of the DEP's claim for civil penalties relating to soil erosion and encroachment of a forested wetland associated with the construction of a well pad, Chesapeake paid $160,000 assessed by the DEP under the Pennsylvania Clean Streams Law and Dam Safety and Encroachments Act. In addition, pursuant to the COA, Chesapeake will take certain corrective actions to implement a planting plan and a wetland mitigation plan approved by the DEP.

Under a Consent Assessment of Civil Penalty dated February 3, 2012, in resolution of the DEP's claim for civil penalties under the Clean Streams Law in connection with erosion and sediment control associated with a pad site, Chesapeake paid a civil penalty and costs in the amount of $215,000. Chesapeake also corrected the issues identified in the DEP's March 2011 compliance order and reimbursed a local water authority for costs incurred as a result of sediment contained in runoff from the pad.

In addition, there are pending against us orders for compliance issued by the West Virginia Department of Environmental Protection (WVDEP) related to alleged violations of the West Virginia Dam Control and Safety Act at four structures constructed for Chesapeake in West Virginia. We have responded to the orders for compliance and continue to work with the WVDEP to resolve the matter. Although we cannot estimate the amount of any monetary sanctions, resolution of these compliance orders can reasonably be expected to include monetary sanctions in excess of $100,000.

There are also outstanding orders for compliance initiated in the 2010 fourth quarter by the U.S. Environmental Protection Agency (EPA) related to our compliance with Clean Water Act (CWA) permitting requirements in West Virginia. We have responded to all pending orders and are actively working with the EPA to resolve these matters. For four of the sites subject to EPA orders for compliance, we have received and have responded to a subpoena requesting documents issued by the grand jury of the U.S. District Court for the Northern District of West Virginia. We understand that the U.S. Department of Justice (DOJ) is investigating possible criminal violations of and liabilities under the CWA with respect to three of the four sites. We are cooperating with the DOJ's investigation. The CWA provides authority for significant civil and criminal penalties for the placement of fill in a jurisdictional stream or wetland without a permit from the Army Corps of Engineers. CWA civil penalties can be as high as $37,500 per day, per violation, and possible criminal penalties range from $2,500 to $25,000 per day, per violation, for misdemeanor liability (i.e., criminally negligent conduct) and from $5,000 to $50,000 per day, per violation, for felony liability (i.e., knowing conduct). The CWA sets forth subjective criteria, including degree of fault and history of prior violations, that influence CWA penalty assessments, and the EPA may also seek to recover the economic benefit derived from non-compliance.

The duration and outcome of the DOJ's investigation are uncertain and the status of the investigation and our assessment of its potential impact may change as the investigation unfolds on a timetable that we cannot confidently predict and that may be affected by developments over the next few quarters. We believe that resolution of the EPA's compliance orders and the DOJ's investigation will each include monetary sanctions exceeding $100,000 but are unable to estimate the amount of any fines that might be imposed in these matters.

ITEM 4. ***Mine Safety Disclosures***

Not applicable.

Part II

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

Price Range of Common Stock 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, 2011:			
Fourth Quarter	$ 29.87	$ 22.00	$ 0.0875
Third Quarter	$ 35.75	$ 25.54	$ 0.0875
Second Quarter	$ 34.70	$ 27.28	$ 0.0875
First Quarter	$ 35.95	$ 25.93	$ 0.0750
Year ended December 31, 2010:			
Fourth Quarter	$ 26.43	$ 20.97	$ 0.0750
Third Quarter	$ 23.00	$ 19.68	$ 0.0750
Second Quarter	$ 25.55	$ 19.62	$ 0.0750
First Quarter	$ 29.22	$ 22.10	$ 0.0750

At February 22, 2012, there were approximately 2,200 holders of record of our common stock and approximately 436,600 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.

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Purchases of Common Stock

The following table presents information about repurchases of our common stock during the three months ended December 31, 2011:

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, 2011 through October 31, 2011	49,091	$ 26.97	—	—
November 1, 2011 through November 30, 2011	23,170	$ 25.59	—	—
December 1, 2011 through December 31, 2011	60,574	$ 22.47	—	—
Total	132,835	$ 24.68	—	—

(a) Reflects the surrender to the Company of 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.

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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, 2011, 2010, 2009, 2008 and 2007. 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, respectively, of this report.

	Years Ended December 31,				
	2011	2010	2009	2008	2007
STATEMENT OF OPERATIONS DATA:	($ in millions, except per share data)				
REVENUES:					
Natural gas and oil	$ 6,024	$ 5,647	$ 5,049	$ 7,858	$ 5,624
Marketing, gathering and compression	5,090	3,479	2,463	3,598	2,040
Oilfield services	521	240	190	173	136
Total Revenues	11,635	9,366	7,702	11,629	7,800
OPERATING EXPENSES:					
Natural gas and oil production	1,073	893	876	889	640
Production taxes	192	157	107	284	216
Marketing, gathering and compression	4,967	3,352	2,316	3,505	1,969
Oilfield services	402	208	182	143	94
General and administrative	548	453	349	377	243
Natural gas and oil depreciation, depletion and amortization	1,632	1,394	1,371	1,970	1,835
Depreciation and amortization of other assets	291	220	244	174	153
(Gains) losses on sales and impairments of fixed assets	(391)	(116)	168	30	—
Impairment of natural gas and oil properties	—	—	11,000	2,800	—
Restructuring	—	—	34	—	—
Total Operating Expenses	8,714	6,561	16,647	10,172	5,150
INCOME (LOSS) FROM OPERATIONS	2,921	2,805	(8,945)	1,457	2,650
OTHER INCOME (EXPENSE):					
Interest expense	(44)	(19)	(113)	(271)	(401)
Earnings (losses) on investments	156	227	(39)	(38)	—
Losses on purchases or exchanges of debt	(176)	(129)	(40)	(4)	—
Impairments of investments	—	(16)	(162)	(180)	—
Other income	23	16	11	27	15
Gain on sale of investments	—	—	—	—	83
Total Other Income (Expense)	(41)	79	(343)	(466)	(303)
INCOME (LOSS) BEFORE INCOME TAXES	2,880	2,884	(9,288)	991	2,347
INCOME TAX EXPENSE (BENEFIT):					
Current income taxes	13	—	4	423	29
Deferred income taxes	1,110	1,110	(3,487)	(36)	863
Total Income Tax Expense (Benefit)	1,123	1,110	(3,483)	387	892

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	Years Ended December 31,				
	2011	2010	2009	2008	2007
	($ in millions, except per share data)				
STATEMENT OF OPERATIONS DATA (continued):					
NET INCOME (LOSS)	1,757	1,774	(5,805)	604	1,455
Net income attributable to noncontrolling interests	(15)	—	(25)	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,742	1,774	(5,830)	604	1,455
Preferred stock dividends	(172)	(111)	(23)	(33)	(94)
Loss on conversion/exchange of preferred stock	—	—	—	(67)	(128)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 1,570	$ 1,663	$ (5,853)	$ 504	$ 1,233
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ 2.47	$ 2.63	$ (9.57)	$ 0.94	$ 2.70
Diluted	$ 2.32	$ 2.51	$ (9.57)	$ 0.93	$ 2.63
CASH DIVIDENDS DECLARED PER COMMON SHARE	$ 0.3375	$ 0.30	$ 0.30	$ 0.2925	$ 0.2625
CASH FLOW DATA:					
Cash provided by operating activities	$ 5,903	$ 5,117	$ 4,356	$ 5,357	$ 4,974
Cash used in investing activities	$ 5,812	$ 8,503	$ 5,462	$ 9,965	$ 7,964
Cash provided by (used in) financing activities	$ 158	$ 3,181	$ (336)	$ 6,356	$ 2,988
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 41,835	$ 37,179	$ 29,914	$ 38,593	$ 30,764
Long-term debt, net of current maturities	$ 10,626	$ 12,640	$ 12,295	$ 13,175	$ 10,178
Total equity	$ 17,961	$ 15,264	$ 12,341	$ 17,017	$ 12,624

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,		
	2011	2010	2009
Net Production:			
Natural gas (bcf)	1,004.1	924.9	834.8
Oil (mmbbl)[a]	31.7	18.4	11.8
Natural gas equivalent (bcfe)[b]	1,194.2	1,035.2	905.5
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 3,133	$ 3,169	$ 2,635
Natural gas derivatives – realized gains (losses)	1,656	1,982	2,313
Natural gas derivatives – unrealized gains (losses)	(669)	425	(492)
Total natural gas sales	4,120	5,576	4,456
Oil sales[a]	2,126	1,079	656
Oil derivatives – realized gains (losses)	(102)	74	33
Oil derivatives – unrealized gains (losses)	(120)	(1,082)	(96)
Total oil sales	1,904	71	593
Total natural gas and oil sales	$ 6,024	$ 5,647	$ 5,049
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 3.12	$ 3.43	$ 3.16
Oil ($ per bbl)[a]	$ 67.11	$ 58.67	$ 55.60
Natural gas equivalent ($ per mcfe)	$ 4.40	$ 4.10	$ 3.63
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 4.77	$ 5.57	$ 5.93
Oil ($ per bbl)[a]	$ 63.90	$ 62.71	$ 58.38
Natural gas equivalent ($ per mcfe)	$ 5.70	$ 6.09	$ 6.22
Other Operating Income[c] ($ in millions):			
Marketing, gathering and compression net margin	$ 123	$ 127	$ 147
Oilfield services net margin	$ 119	$ 32	$ 8
Other Operating Income[c] ($ per mcfe):			
Marketing, gathering and compression net margin	$ 0.10	$ 0.12	$ 0.16
Oilfield services net margin	$ 0.10	$ 0.03	$ 0.01
Expenses ($ per mcfe):			
Production expenses	$ 0.90	$ 0.86	$ 0.97
Production taxes	$ 0.16	$ 0.15	$ 0.12
General and administrative expenses	$ 0.46	$ 0.44	$ 0.38
Natural gas and oil depreciation, depletion and amortization	$ 1.37	$ 1.35	$ 1.51
Depreciation and amortization of other assets	$ 0.24	$ 0.21	$ 0.27
Interest expense[d]	$ 0.03	$ 0.08	$ 0.22
Interest Expense ($ in millions):			
Interest expense[d]	$ 30	$ 99	$ 227
Interest rate derivatives – realized (gains) losses	7	(14)	(23)
Interest rate derivatives – unrealized (gains) losses	7	(66)	(91)
Total interest expense	$ 44	$ 19	$ 113

(a) Includes NGLs.

(b) Natural gas equivalent is based on six mcf of natural gas to one barrel of oil. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given recent commodity prices, the price for an mcfe of natural gas is significantly less than the price for an mcfe of oil or NGLs.

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

(d) 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 oilfield services. We refer you to Note 17 of the notes to our consolidated financial statements in Item 8 of this report, which summarizes by segment our net income and capital expenditures for 2011, 2010 and 2009 and our assets as of December 31, 2011, 2010 and 2009.

Executive Summary

We are the second-largest producer of natural gas, a top 15 producer of liquids and the most active driller of new wells in the U.S. We own interests in approximately 45,700 producing natural gas and oil wells that are currently producing approximately 3.5 bcfe per day, net to our interest. The Company has built a large resource base of onshore U.S. natural gas assets in the Haynesville and Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania; the Barnett Shale in the Fort Worth Basin of north-central Texas; and the Pearsall Shale in South Texas. In addition, we have built leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas; the Utica Shale in Ohio and Pennsylvania; the Granite Wash, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in western Oklahoma and the Texas Panhandle; the Bone Spring, Avalon, Wolfcamp and Wolfberry plays in the Permian and Delaware Basins in West Texas and southern New Mexico; and the Niobrara Shale in the Powder River Basin in Wyoming. We have also vertically integrated many of our operations and own substantial midstream, compression and oilfield services assets as discussed under *Business Strategy* in Item 1.

Proved Reserves. Chesapeake began 2011 with estimated proved reserves of 17.096 tcfe and ended with 18.789 tcfe as of December 31, 2011, an increase of 1.693 tcfe, or 10%. The 2011 proved reserve movement included 1.194 tcfe of production, 5.683 tcfe of extensions, 64 bcfe of negative performance revisions to previous estimates and 14 bcfe of positive revisions resulting from higher oil prices using the average first-day-of-the-month price for the twelve months ended December 31, 2011, compared to the twelve months ended December 31, 2010. During 2011, we acquired 30 bcfe of estimated proved reserves and divested 2.776 tcfe of estimated proved reserves, including the disposition of 2.420 tcfe associated with the sale of our Fayetteville Shale assets in March 2011 (as described below under *Steps Taken in 2011 to Implement Our Business Strategy*). The 64 bcfe of negative revisions to previous estimates consisted of 337 bcfe of negative revisions associated with the deletion of PUDs no longer consistent with our development plans, offset by 273 bcfe of positive revisions to producing properties and proved undeveloped reserves estimates.

Drilling and Completion Expenditures. During 2011, we invested $6.036 billion in operated wells (using an average of 167 operated rigs) and $1.509 billion in non-operated wells (using an average of 97 non-operated rigs) for total drilling and completing costs on proved and unproved properties of $7.545 billion, net of drilling and completion carries of $2.570 billion.

Production. Our total 2011 production of 1.194 tcfe consisted of 1.004 tcf of natural gas (84% on a natural gas equivalent basis) and 31.676 mmbbls of liquids (16% on a natural gas equivalent basis). Daily production for 2011 averaged 3.272 bcfe, an increase of 436 mmcfe, or 15%, over the 2.836 bcfe produced per day in 2010. This was our 22nd consecutive year of sequential production growth.

In 2012, Chesapeake has curtailed its natural gas production approximately 1.0 bcf per day of gross operated natural gas production, or approximately 1.5% of U.S. lower 48 natural gas production, in response to continued low natural gas prices and as an effort to help bring U.S. natural gas supply and demand into better balance. The curtailed volumes are located primarily in the Haynesville and Barnett shale plays. In addition, wherever possible, the company is deferring completions of dry gas wells that have been drilled, but not yet completed, and is also deferring pipeline connections of dry gas wells that have already been completed. As a result of production curtailments and reduced drilling and completion activity, partially offset by growth in associated natural gas production in liquids-rich plays, Chesapeake projects that its 2012 net natural gas production will average approximately 2.65 bcf per day, a decrease of 100 mmcf per day, or 4%, compared to the Company's 2011 average net natural gas production of 2.75 bcf per day.

Leasehold and Seismic Inventories. Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (15.3 million net acres) and 3-D seismic (30.8 million acres) in the U.S. We have accumulated the largest inventory of U.S. natural gas shale play leasehold (2.2 million net acres) and own a leading position in 11 of what we believe are the top 15 unconventional liquids-rich plays in the U.S. We are currently using 161 operated drilling rigs to further develop our inventory of approximately 39,200 net drillsites. The company is targeting to invest approximately $1.4 billion in net undeveloped leasehold expenditures in 2012, of which approximately 90% will be in liquids-rich plays and 100% will be in plays where the company is already active. This compares to net undeveloped leasehold expenditures of approximately $3.5 billion and $5.8 billion in 2011 and 2010, respectively.

Emphasis on Increasing Liquids Production. In recognition of the value gap between liquids and natural gas prices, Chesapeake has directed a significant portion of its technological and leasehold acquisition expertise during the past three years to identify, secure and commercialize new unconventional liquids-rich plays. This planned transition will result in a more balanced and likely more profitable portfolio between natural gas and liquids. To date, we have built leasehold positions and established production in multiple liquids-rich plays on approximately 6.6 million net acres with 830 million bbls of oil equivalent of proved reserves. Our production of liquids averaged 86,784 bbls per day during 2011, a 72% increase over the average during 2010, as a result of the increased development of our unconventional liquids-rich plays. We are projecting that the portion of our operated drilling and completion expenditures allocated to liquids development will reach 85% in 2012, and we expect to increase our liquids production through our drilling activities to an average of approximately 150,000 bbls per day in 2012 and to more than 200,000 bbls per day in 2013 and 250,000 bbls per day by 2015.

Other Operational Segments. In addition to our exploration and production operational segment, we also have a marketing, gathering and compression operational segment and an oilfield services operational segment that we utilize as a financial and operational hedge against inflation and to assure that we have access to quality services. In October 2011, we formally segregated our oilfield services businesses under our wholly owned subsidiary, COS, and its wholly owned subsidiary COO. COO's subsidiaries include a leading U.S. drilling contractor, oilfield trucking company, oilfield rental tool provider and a developing pressure pumping business. In September 2009, we formally segregated our midstream gathering services under a wholly owned subsidiary, CMD, and it has engaged in significant sales transactions with our affiliate midstream master limited partnership. These segments are separately capitalized, each with its own revolving bank credit facility, and COO issued senior notes in 2011.

Steps Taken in 2011 to Implement Our Business Strategy

Our business strategy is to create value for investors by building and developing one of the largest onshore natural gas and liquids resource bases in the U.S. The key elements of our business strategy, as described in *Business Strategy* in Item 1, are the following:

- growing production and proved reserves through the drillbit;
- controlling substantial land and drilling location inventories and building operating focus and scale;
- developing proprietary technological advantages;
- focusing on achieving low costs through our focused activities, vertical integration and increasing scale;
- mitigating natural gas and oil price risk through our hedging program;
- entering into value-creating joint ventures;
- improving our balance sheet through reduction of debt;
- transforming the U.S. transportation fuels market and increasing demand for U.S. natural gas; and
- maintaining an entrepreneurial culture.

Below we describe significant activities in 2011 that evidence our commitment to our business strategy.

Joint Ventures. In February 2011, we entered into a joint venture with a wholly owned subsidiary of CNOOC Limited (CNOOC) to sell a 33.3% undivided interest in approximately 800,000 net acres of leasehold overlaying the Niobrara Shale, Codell Sand and various other formations in the Powder River and DJ basins in northeast Colorado and southeast Wyoming. Under the terms of the joint venture, 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. CNOOC has the right to a 33.3% participation in any additional leasehold we acquire in the joint venture area of mutual interest at cost plus a fee.

In December 2011, we entered into a joint venture with Total E&P, USA, Inc., a wholly owned subsidiary of Total S.A. (Total), in the liquids-rich area of the Utica Shale. Under the terms of the joint venture, Total acquired an undivided 25% interest in approximately 619,000 net acres of leasehold, of which Chesapeake contributed approximately 542,000 net acres and Enervest, Ltd. contributed approximately 77,000 net acres to the joint venture, covering all or a portion of 10 counties in eastern Ohio. We received approximately $610 million in cash at closing and approximately $1.42 billion will be paid in the form of a drilling and completion cost carry, which we anticipate fully receiving by year-end 2014. In addition, Total will acquire a 25% share in any additional acreage we acquire in the joint venture area of mutual interest at cost plus a fee.

As of December 31, 2011, including the joint ventures described above, we had entered into seven significant joint ventures with other leading energy companies pursuant to which we sold a portion of our leasehold, producing properties and other assets located in seven different resource plays and received cash of $7.1 billion and commitments for future drilling and completion cost sharing of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all

leasing, drilling, completion, operations and marketing activities for the project. These transactions have allowed us to recover much or all of our initial leasehold investments and reduce our ongoing capital costs in these plays. The transactions are detailed below.

Primary Play	Joint Venture Partner[a]	Joint Venture Date	Interest Sold	Cash Proceeds Received at Closing	Total Drilling Carries	Drilling Carries Remaining[b]
				($ in millions)		
Utica	TOT	December 2011	25.0%	$ 610	$ 1,422	$ 1,422
Niobrara	CNOOC	February 2011	33.3%	570	697	570
Eagle Ford & Pearsall	CNOOC	November 2010	33.3%	1,120	1,080	144
Barnett	TOT	January 2010	25.0%	800	1,404[c]	—
Marcellus	STO	November 2008	32.5%	1,250	2,125	223
Fayetteville	BP	September 2008	25.0%	1,100	800	—
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508[d]	—
				$ 7,100	$ 9,036	$ 2,359

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

(b) As of December 31, 2011.

(c) In conjunction with an agreement requiring us to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012, TOT accelerated the payment of its remaining joint venture drilling carry in exchange for an approximate 9% reduction in the total amount of drilling carry obligation owed to us at that time. As a result, in October 2011, we received $471 million in cash from TOT, which included $46 million of carry obligation billed and $425 million for the remaining carry obligation. In January 2012, Chesapeake and TOT agreed to reduce the minimum rig count from 12 to six rigs.

(d) In September 2009, PXP accelerated the payment of its remaining carry in exchange for an approximate 12% reduction to the remaining drilling carry obligation owed to us at that time.

The drilling and completion carries in our joint venture agreements create a significant cost advantage that allows us to reduce our future finding costs. During 2011 and 2010, our drilling and completion costs included the benefit of approximately $2.570 billion and $1.151 billion, respectively, of drilling and completion carries. Our drilling and completion costs for 2012, 2013 and 2014 will continue to be partially offset by the use of our remaining drilling and completion carries associated with our joint venture agreements.

During 2011, as part of our joint venture agreements with CNOOC, TOT, STO and PXP, we sold interests in additional leasehold in the Niobrara, Eagle Ford and Pearsall, Barnett, Marcellus and Haynesville and Bossier shale plays for proceeds of approximately $511 million that had an estimated cost to us of approximately $311 million. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Fayetteville Shale Asset Monetization. In March 2011, we sold all of our Fayetteville Shale assets in central Arkansas to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited, for net proceeds of approximately $4.65 billion in cash. The sold properties consisted of approximately 487,000 net acres of leasehold, net production at closing of approximately 415 mcfe per day and midstream assets consisting of approximately 420 miles of pipeline. As part of the transaction, we

agreed to provide technical and business services for up to one year for BHP Billiton's Fayetteville properties for an agreed-upon fee. We used a portion of the funds we received from the Fayetteville transaction to purchase outstanding debt as described below.

Purchases of Senior Debt. In May 2011, we completed tender offers to purchase $1.373 billion in aggregate principal amount of certain of our senior notes and $531 million in aggregate principal amount of certain of our contingent convertible senior notes. These tender offers were part of our plan to reduce the amount of our outstanding indebtedness by 25% in the two-year period ending December 31, 2012. We funded the purchase of the notes with a portion of the net proceeds we received from the monetization of our Fayetteville Shale assets. Combined with the $140 million in aggregate principal amount of contingent convertible senior notes we purchased in privately negotiated transactions, we retired an aggregate principal amount of $2.044 billion of senior notes and contingent convertible senior notes in 2011.

Volumetric Production Payment (VPP). In May 2011, we monetized certain of our producing assets in the Mid-Continent through a ten-year VPP for proceeds of approximately $853 million. The transaction included approximately 177 bcfe of proved reserves and approximately 80 mmcfe per day of net production. Chesapeake has retained drilling rights on the properties below currently producing intervals and outside of existing producing wellbores and we also retain all production beyond the specified volumes sold in the transaction. This transaction was our ninth VPP. The cash proceeds for this transaction were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. Other VPPs we completed in 2007 – 2010 are detailed in Note 11 of the consolidated financial statements included in Item 8 of this report.

Bronco Drilling Acquisition. As an extension of our oilfield services vertical integration strategy, in June 2011 we acquired Bronco Drilling Company, Inc., a publicly traded company, for an aggregate purchase price of approximately $339 million, or $11.00 per share of Bronco common stock. The acquisition included 22 high-quality drilling rigs primarily operating in the Williston and Anadarko basins which were transferred to our drilling subsidiary, Nomac Drilling, L.L.C.

CNGV Investments. In July 2011, CNGV, a wholly owned subsidiary, made its first two investments in companies and technologies that we believe have the potential to replace the use of gasoline and diesel derived primarily from imported oil with domestic oil, natural gas and natural gas-to-liquids fuels. We agreed to invest $150 million in newly issued convertible promissory notes of Clean Energy Fuels Corp. (Nasdaq:CLNE), based in Seal Beach, California. The investment will be made in three equal $50 million promissory notes, the first of which was issued in July 2011, with the remaining notes scheduled to be issued in June 2012 and June 2013. The notes bear interest at the annual rate of 7.5%, payable quarterly, and are convertible at our option into shares of Clean Energy's common stock at a 22.5% conversion premium, resulting in a conversion price of $15.80 per share. If certain requirements have been met following the second anniversary of the issuance of a note, Clean Energy can force conversion of the debt. The entire principal balance of each note is due and payable seven years following issuance. Clean Energy will use our $150 million investment to accelerate its build-out of LNG fueling infrastructure for heavy-duty trucks at truck stops across interstate highways in the U.S.

Also in July 2011, CNGV agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Louisville, Colorado. The investment over the next two years will fund construction of a waste biomass-based "green gasoline" plant, capable of annually producing more than 40 million gallons of gasoline from natural gas and cellulosic material. The investment is intended to accelerate the development of an affordable, stable, room-temperature, natural gas-based fuel for immediate use in automobiles, diesel engine vehicles and aircraft. The first $35 million tranche of our investment was funded in July 2011 and the remaining

tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached over the next two years. The full investment will represent approximately 50% of Sundrop Fuels' equity on a fully diluted basis.

Oilfield Services Capitalization. In October 2011, our wholly owned subsidiary, COO, issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. COO used a portion of the net proceeds of approximately $637 million from the placement to make a cash distribution to its direct parent, COS, to enable it to reduce indebtedness under an intercompany note with Chesapeake. Chesapeake used the cash distribution to repay outstanding indebtedness under its corporate revolving bank credit facility. In November 2011, COO established a five-year syndicated revolving bank credit facility with $500 million in total commitments (we estimate the capacity was limited to approximately $290 million as of December 31, 2011 by certain restrictive provisions). Borrowings under the credit facility are secured by liens on all of the equity interests of COO and COO's current and future guarantor subsidiaries and all of their assets, including real and personal property.

Utica Financial Transaction. CHK Utica, L.L.C. (CHK Utica) is an unrestricted, non-guarantor consolidated subsidiary we formed in October 2011 to develop a portion of our Utica Shale natural gas and oil assets. In exchange for all of the common shares, we contributed to CHK Utica approximately 700,000 net acres of leasehold within an area of mutual interest in the Utica Shale play covering 13 counties located primarily in eastern Ohio. During November and December 2011, in private placements, third-party investors contributed $1.25 billion in cash to CHK Utica in exchange for (i) 1.25 million CHK Utica preferred shares, and (ii) our obligation to deliver a 3% overriding royalty interest (ORRI) in up to 1,500 net wells to be drilled on certain of our Utica Shale leasehold. Dividends on the preferred shares are payable on a quarterly basis at a rate of 7% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, cash flow from the assets owned by CHK Utica are insufficient to fund the dividend in full in any quarter. We have committed to drill, for the benefit of CHK Utica, a minimum of 50 net wells per year through 2016 in the CHK Utica area of mutual interest, up to a minimum cumulative total of 250 net wells. As the managing member of CHK Utica, we may, at our sole discretion and election at any time after December 31, 2013, distribute certain excess cash of CHK Utica. If we are current in our drilling commitment at the time, any such optional distribution of excess cash is allocated 70% to the preferred shares (which is applied toward redemption of the preferred shares) and 30% to the common shares. We may also cause CHK Utica to redeem the CHK Utica preferred shares for cash, in whole or in part, at a valuation equal to the greater of a 10% internal rate of return or a return on investment of 1.4x, in each case inclusive of dividends paid at the rate of 7% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to October 31, 2018, the optional redemption valuation increases to the greater of a 17.5% internal rate of return or a return on investment of 2.0x. As of December 31, 2011, the redemption price, and the liquidation preference, was $1,400 per preferred share. CHK Utica is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. CHK Utica also receives its proportionate share of the benefit of the drilling carry associated with our joint venture with Total in the Utica Shale. For further discussion, see *Noncontrolling Interests* in Note 8 of the notes to our consolidated financial statements in Item 8 of this report.

Royalty Trust. In November 2011, the Chesapeake Granite Wash Trust (the Trust), a newly formed Delaware statutory trust, completed its initial public offering of 23,000,000 common units representing an approximate 49% beneficial interest in the Trust. Net proceeds to the Trust, after certain offering expenses, were approximately $410 million. Concurrent with the closing, we conveyed certain royalty interests to the Trust in exchange for the net proceeds of the Trust's initial public offering and 23,750,000 units (12,062,500 common units and 11,687,500 subordinated units) representing approximately 51% of the beneficial interest in the Trust. The royalty interests conveyed by Chesapeake will entitle the Trust to a percentage of the proceeds received by Chesapeake from the production of hydrocarbons from 69 producing wells and 118 development wells to be drilled by

Chesapeake by June 30, 2016 on approximately 45,400 gross acres (28,700 net acres) in the Colony Granite Wash play in Washita County in western Oklahoma. For further discussion, see *Noncontrolling Interests* in Note 8 of the notes to our consolidated financial statements in Item 8 of this report.

Marcellus Gathering System Sale. In December 2011, our wholly owned midstream subsidiary, CMD, sold its wholly owned subsidiary, AMS, which held substantially all of our Marcellus Shale midstream assets, to our affiliate, CHKM, for total consideration of $879 million, subject to a customary post-closing working capital adjustment. At closing, we received cash of $600 million and 9,791,605 common units of CHKM that had a value at closing of $279 million. The stock consideration increased our ownership in CHKM from 42.3% to 46.1%. The assets sold included an approximate 47% ownership of an integrated system of assets that consist of 200 miles of pipeline in the Marcellus Shale. In addition, CMD has committed to pay CHKM any quarterly shortfall between the actual EBITDA from the assets sold and specified quarterly targets, which total $100 million in 2012 and $150 million in 2013. We, and other producers in the area, have 15-year fixed fee gathering and compression agreements with AMS that include significant acreage dedications and an annual fee redetermination.

Capital Expenditures

Our exploration, development and acquisition activities require us to make substantial capital expenditures. Our current budgeted drilling and completion expenditures, net of drilling and completion carries, are $7.0 – $7.5 billion in 2012, compared to $7.5 billion in 2011. Our operated dry gas drilling expenditures in 2012, net of drilling and completion cost carries, are expected to decrease to $0.9 billion, a decrease of approximately 70% from similar expenditures of $3.1 billion in 2011 and the Company's lowest expenditures on dry gas plays since 2005. We are projecting that the portion of our operated drilling and completion expenditures allocated to liquids development will reach 85% in 2012.

Our projected 2012 capital expenditures for our growing midstream and oilfield services businesses are $2.5 – $3.5 billion, and we are targeting to invest approximately $1.4 billion in net undeveloped leasehold expenditures in 2012, of which approximately 90% will be in liquids-rich plays and 100% will be in plays where the Company is already active. This compares to net undeveloped leasehold expenditures of approximately $3.5 billion and $5.8 billion in 2011 and 2010, respectively.

Liquidity and Capital Resources

Liquidity Overview

As discussed in *Recent Developments*, in Item 1, we anticipate funding our 2012 drilling and completion expenditures, and other capital expenditures, including leasehold acquisitions, using a combination of cash flow from operations and proceeds from asset monetizations, including joint ventures, volumetric production payments, financial transactions and other property and investment dispositions in 2012. In addition, since early 2011, it has been our plan to reduce our long-term debt to no more than $9.5 billion at December 31, 2012, a 25% reduction from year-end 2010, and increase our production by 25% during the two years ended December 31, 2012.

We expect that the proceeds from our 2012 planned monetization transactions, which we estimate could be $10 – $12 billion, will be sufficient to fund our budgeted capital expenditures, meet our long-term debt reduction plans by year-end 2012 and provide additional liquidity for 2013. We are also projecting that our increasing liquids production will enable us to reach equilibrium between our cash flow from operations and planned drilling and completion expenditures in 2014. We do not have binding agreements for any of these transactions, however, and our ability to consummate each of them is subject to changes in market conditions and other factors. As a result, there can be no assurance that we will complete any of the announced transactions on a timely basis or at all. If we are unable to consummate these transactions or if they do not generate the proceeds we are anticipating, we would be required to seek funds from other sources. Our ability to obtain capital from asset monetizations is dependent upon many factors, and they may be beyond our control. If our access to alternative asset monetizations were limited, we could be required to reduce our capital spending, which could reduce our ability to develop and replace our reserves.

Through the vertical integration of our business and as operator of a substantial number of our properties under development, we retain significant control and flexibility over the development plan and the associated timing, which we believe is instrumental to our business plan and strategy. While our capital raising activities enabled us to fund our capital program in 2011 and pursue our goal of long-term debt reduction, certain recent transactions require us to meet performance obligations and we have significant other contractual cash obligations to third parties pursuant to various lease arrangements, gathering, processing, and transportation agreements, drilling commitments, leasehold maintenance arrangements, fleet utilization agreements, and investments in new ventures (see Note 4 of the notes to our consolidated financial statements included in Item 8 of this report). While our business plan assumes that we will meet these commitments in the ordinary course of business, we are required to meet our performance and payment obligations regardless of whether our business plan changes for circumstances beyond our control.

Sources 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 $5.903 billion in 2011, compared to $5.117 billion in 2010 and $4.356 billion in 2009. 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 depreciation, depletion and amortization, deferred income taxes, mark-to-market changes in our derivative instruments and gains or losses on the sales and impairments of fixed assets. See the discussion below under *Results of Operations*.

Changes in market prices for natural gas and oil directly impact 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. As natural gas and oil prices dip and reach supportable low prices, however, we may take the opportunity to close out open swap positions in order to lock in substantial mark-to-market gains. For example, during 2011, we elected to close all our natural gas swap positions thereby locking in approximately $353 million of gains for 2012 and positioning us to be able to react to market increases in the future by potentially adding new positions, although also exposing us to declining prices if we are unhedged. Our natural gas and oil derivatives as of December 31, 2011 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 derivative positions.

Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivative is deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows. In 2011, 2010 and 2009, we received $1.043 billion, $621 million and $109 million, respectively, for settlements of derivatives which were classified as cash flows from financing activities.

Our $4.0 billion corporate revolving bank credit facility, our $600 million midstream revolving bank credit facility (which we estimate was limited to approximately $280 million as of December 31, 2011), our $500 million oilfield services revolving bank credit facility (which we estimate was limited to approximately $290 million as of December 31, 2011) 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 $15.509 billion and repaid $17.466 billion in 2011, we borrowed $15.117 billion and repaid $13.303 billion in 2010 and we borrowed $7.761 billion and repaid $9.758 billion in 2009 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 oilfield services facility is secured by liens on all of the equity interests of COO and COO's current and future guarantor subsidiaries and all of their 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 2011, 2010 and 2009:

	2011		2010		2009	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
	($ in millions)					
Senior notes[a]	$ 1,650	$ 1,614	$ 2,000	$ 1,967	$ 1,425	$ 1,346
Convertible preferred stock	—	—	2,600	2,562	—	—
Total	$ 1,650	$ 1,614	$ 4,600	$ 4,529	$ 1,425	$ 1,346

(a) 2011 included $650 million principal amount of 6.625% Senior Notes due 2012 issued by COO for net proceeds of $637 million.

The following table reflects proceeds we received from our significant natural gas and oil asset monetizations in 2011, 2010 and 2009:

	2011	2010	2009
		($ in millions)	
Natural gas and oil property monetizations:			
TOT (Utica) joint venture	$ 610	$ —	$ —
CNOOC (Niobrara) joint venture[a]	619	—	—
CNOOC (Eagle Ford) joint venture[b]	201	1,085	—
TOT (Barnett) joint venture[c]	490	891	—
STO (Marcellus) joint venture[d]	165	389	9
PXP (Haynesville) joint venture[e]	14	16	1,129
BHP (Fayetteville) divestiture	4,270	—	—
Volumetric production payments	849	1,622	408
Other divestitures	433	289	380
Total	$ 7,651	$ 4,292	$ 1,926

(a) 2011 includes $66 million in proceeds from sales of additional acreage in the Niobrara area of mutual interest to CNOOC.

(b) 2011 includes proceeds from sales of additional acreage in the Eagle Ford area of mutual interest to CNOOC.

(c) 2011 and 2010 include $65 million and $38 million in proceeds, respectively, for sales of additional acreage in the Barnett area of mutual interest to TOT. In addition, 2011 includes the $425 million acceleration of the payment of TOT's remaining drilling carry in exchange for a reduction in the obligation. See Note 11 in Item 8 of this report for further discussion.

(d) 2011, 2010 and 2009 amounts for sales of additional acreage in the Marcellus area of mutual interest to STO.

(e) 2011 and 2010 amounts for proceeds from sales of additional acreage in the Haynesville area of mutual interest to PXP. 2009 includes the acceleration of the payment of PXP's remaining drilling carry in exchange for a reduction in the obligation. See Note 11 in Item 8 of this report for further discussion.

In December 2011, our wholly owned midstream subsidiary, CMD sold substantially all of its natural gas gathering systems and related facilities in the Marcellus Shale through the sale of its subsidiary, AMS, to CHKM for total consideration of $879 million. The $879 million consisted of $279 million in CHKM common units and $600 million cash.

In November 2011 and December 2011, third-party investors contributed $1.25 billion in cash to CHK Utica, L.L.C. in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3% overriding royalty interest in up to 1,500 net wells to be drilled on certain of our Utica Shale leasehold. CHK Utica, L.L.C. is an unrestricted, non-guarantor consolidated subsidiary we formed in October 2011 to develop a portion of our Utica Shale natural gas and oil assets.

In November 2011, the Chesapeake Granite Wash Trust (the Trust), a newly formed Delaware statutory trust, completed its initial public offering of 23,000,000 common units representing an approximate 49% beneficial interest in the Trust. Net proceeds to the Trust, after certain offering expenses, were approximately $410 million. Concurrent with the closing, we conveyed certain royalty interests to the Trust in exchange for the net proceeds of the Trust's initial public offering and 23,750,000 units (12,062,500 common units and 11,687,500 subordinated units) representing approximately 51% of the beneficial interest in the Trust.

In December 2010, CMD 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.

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 2011 and 2010, we received cash distributions of $85 million and $88 million, respectively, from CHKM and its predecessor. In addition, in 2011 and 2010, we received cash distributions of $28 million and $58 million, respectively, from our equity investee, FTS International, LLC and its predecessor. These cash distributions were accounted for as a return on investment and reflected as cash flows from operating activities. In 2011, we also received $206 million from FTS International, LLC at the time of its recapitalization. This cash distribution was accounted for as a return of investment and reflected as cash flows from investing activities.

Uses of Funds

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 2011, 2010 and 2009. 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.

In May 2011, we completed and settled tender offers to purchase the following senior notes and contingent convertible senior notes in order to reduce the amount of our outstanding indebtedness. We funded the purchase of the notes with a portion of the net proceeds we received from the sale of our Fayetteville Shale assets.

	Principal Amount Purchased
	($ in millions)
7.625% senior notes due 2013	$ 36
9.5% senior notes due 2015	160
6.25% euro-denominated senior notes due 2017[(a)]	380
6.5% senior notes due 2017	440
6.875% senior notes due 2018	126
7.25% senior notes due 2018	131
6.625% senior notes due 2020	100
Total senior notes	1,373
2.75% contingent convertible senior notes due 2035	55
2.5% contingent convertible senior notes due 2037	210
2.25% contingent convertible senior notes due 2038	266
Total contingent convertible senior notes	531
Total	$ 1,904

(a) We purchased €256 million in aggregate principal amount of our euro-denominated senior notes which had a value of $380 million based on the exchange rate of $1.4821 to €1.00. Simultaneously with our purchase of the euro-denominated senior notes, we unwound cross currency swaps for the same principal amount.

We paid $2.058 billion in cash for the tender offers described above and recorded associated losses of approximately $174 million. The losses included $154 million in cash premiums, $20 million of deferred charges, $160 million of note discounts and $2 million of interest rate hedging losses, offset by $162 million of the equity component of the contingent convertible notes.

In March 2011, we repurchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $128 million. Associated with these repurchases, we recognized a loss of $2 million.

In August 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. In September 2010, we redeemed in whole 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 tender offers and redemptions, we recognized a loss of $40 million.

In July 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 June 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.

We paid dividends on our common stock of $207 million, $189 million and $181 million in 2011, 2010 and 2009, respectively. The Board of Directors increased the quarterly dividend on our common stock from $0.075 to $0.0875 per share beginning with the dividend paid in July 2011. We paid dividends on our preferred stock of $172 million, $92 million and $23 million in 2011, 2010 and 2009, respectively. The increases in 2011 and 2010 were due to the issuance of 2.6 million shares of preferred stock in 2010.

Credit Risk

Derivative instruments enable us to mitigate 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 counterparties that are rated investment-grade and 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, 2011, our commodity and interest rate derivative instruments were spread among 17 counterparties. Additionally, the counterparties under our multi-counterparty secured hedging facility are required to secure their natural gas and oil hedging obligations in excess of defined thresholds. We use this facility for the majority of our natural gas, oil and natural gas liquids derivatives.

Our accounts receivable are primarily from purchasers of natural gas and oil ($1.089 billion at December 31, 2011) and exploration and production companies which own interests in properties we operate ($1.171 billion at December 31, 2011). 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 2011 and 2010, 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 $5.812 billion in 2011, compared to $8.503 billion in 2010 and $5.462 billion in 2009. The majority of the decrease in investing activities in 2011 was the result of our decreased acquisition of unproved properties and additional asset monetizations, offset by an increase in drilling and completion activities. 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 drilling and completion activities. Investing activities in 2009 were at a reduced rate in response to a low natural gas price environment and lower demand. In each of 2011, 2010 and 2009, we also invested in drilling rigs, gathering systems, compressors, and other property and equipment to support our natural gas and oil exploration, development and production activities. The following table details our cash used in investing activities during 2011, 2010 and 2009:

	Years Ended December 31,		
	2011	2010	2009
		($ in millions)	
Natural Gas and Oil Investing Activities:			
Drilling and completion costs on proved and unproved properties	$ (7,257)	$ (5,061)	$ (3,410)
Acquisition of proved properties	(48)	(243)	(5)
Acquisition of unproved properties	(4,296)	(6,015)	(1,666)
Proceeds from divestitures of proved and unproved properties	7,651	4,292	1,926
Geological and geophysical costs[(a)]	(210)	(181)	(162)
Interest capitalized on unproved properties	(630)	(687)	(598)
Deposits for acquisitions of proved and unproved properties	—	(43)	—
Total natural gas and oil investing activities	(4,790)	(7,938)	(3,915)
Other Investing Activities:			
Additions to other property and equipment	(2,009)	(1,326)	(1,683)
Acquisition of drilling company	(339)	—	—
Proceeds from sales of other assets	1,312	883	176
Proceeds from (additions to) investments	101	(134)	(40)
Other	(87)	12	—
Total other investing activities	(1,022)	(565)	(1,547)
Total cash used in investing activities	$ (5,812)	$ (8,503)	$ (5,462)

(a) Including related capitalized interest.

Bank Credit Facilities

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

	Corporate Credit Facility[a]	Midstream Credit Facility[b]	Oilfield Services Credit Facility[c]
		($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	June 2016	November 2016
Borrowing capacity	$ 4,000	$ 600[d]	$ 500[e]
Amount outstanding as of December 31, 2011	$ 1,719	$ 1	$ 29
Letters of credit outstanding as of December 31, 2011	$ 38	$ —	$ —

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

(b) Borrower is Chesapeake Midstream Operating, L.L.C.

(c) Borrower is Chesapeake Oilfield Operating, L.L.C.

(d) We estimate the capacity was limited to approximately $280 million as of December 31, 2011 by certain restrictive provisions.

(e) We estimate the capacity was limited to approximately $290 million as of December 31, 2011 by certain restrictive provisions.

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, our credit facilities do not contain provisions which would trigger an acceleration of amounts due under the respective 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 determined 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, 2011. 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 $600 million midstream syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems in support of 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 other than certain joint venture equity interests, of the wholly owned subsidiaries (the restricted subsidiaries) of CMD, itself a wholly owned subsidiary of Chesapeake. Amounts outstanding 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 1.00% to 1.75% or (ii) the Eurodollar rate, which is based on LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. 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 midstream master limited partnership affiliate, CHKM. In December 2011, the leverage ratio increased for a three-fiscal-quarter period beginning October 1, 2011 due to the sale of CMD's wholly owned subsidiary, AMS, as it was classified as a material disposition of assets. We were in compliance with all covenants under the agreement at December 31, 2011. 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 CMD and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

Oilfield Services Credit Facility

In November 2011, we closed on a new syndicated revolving bank credit facility for our oilfield services operations, which have recently been segregated under the wholly owned subsidiary, COS, and its wholly owned subsidiary, COO. The facility matures in November 2016, has initial commitments of $500 million and may be expanded to $900 million at COO's option, subject to additional bank participation. The facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. Borrowings under the credit facility are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries), and bear interest at our option at either (i) the greater of the reference rate of Bank of America, N.A., the federal funds effective rate plus 0.50%, and one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 1.00% to 1.75% per annum or (ii) the Eurodollar rate, which is based on LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused

portion of the credit facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The oilfield services credit facility agreement contains various covenants and restrictive provisions which limit the ability of COO 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 lease adjusted indebtedness to EBITDAR, a senior secured leverage ratio based on the ratio of secured indebtedness to EBITDA and a fixed charge coverage ratio based on the ratio of lease adjusted interest expense to EBITDAR, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at December 31, 2011. If COO 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 oilfield services credit facility agreement also has cross default provisions that apply to other indebtedness COO and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

Hedging Facility

We have a multi-counterparty secured hedging facility with 18 counterparties that have committed to provide approximately 6.5 tcfe of hedging capacity for commodity price derivatives and 6.5 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.5 billion under the terms of the facility. As of December 31, 2011, we had hedged under the facility 2.1 tcfe of our future production with price derivatives and 0.1 tcfe with basis derivatives. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and natural gas liquids price and basis derivative instruments 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 certain 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 trading capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based trading limits are applied separately to price and basis derivative instruments. In addition, there are volume-based sub-limits for natural gas, oil and natural gas liquids derivative instruments. 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 derivative instruments 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.

Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities discussed above, as of December 31, 2011, our long-term debt consisted of the following ($ in millions):

7.625% senior notes due 2013	$ 464
9.5% senior notes due 2015	1,265
6.25% euro-denominated senior notes due 2017[(a)]	446
6.5% senior notes due 2017	660
6.875% senior notes due 2018	474
7.25% senior notes due 2018	669
6.625% senior notes due 2019[(b)]	650
6.625% senior notes due 2020	1,300
6.875% senior notes due 2020	500
6.125% senior notes due 2021	1,000
2.75% contingent convertible senior notes due 2035[(c)]	396
2.5% contingent convertible senior notes due 2037[(c)]	1,168
2.25% contingent convertible senior notes due 2038[(c)]	347
Discount on senior notes[(d)]	(490)
Interest rate derivatives[(e)]	28
	$ 8,877

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.2973 to €1.00 as of December 31, 2011. See Note 9 of our consolidated financial statements included in Item 8 of this report for information on our related foreign currency derivatives.

(b) Issuers are COO and Chesapeake Oilfield Finance, Inc., a wholly owned subsidiary of COO formed solely to facilitate the offering of the 6.625% Senior Notes due 2019. It is nominally capitalized and has no operations or revenues. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the fourth quarter of 2011, 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 2012 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	$ 48.51	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.16	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.27	June 14, 2019

(d) Included in this discount is $444 million associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

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

Chesapeake Senior Notes and Contingent Convertible Notes

The Chesapeake senior notes and the contingent convertible senior notes, as defined in note (b) to the table above, are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Chesapeake's obligations under the senior notes and the contingent convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our wholly owned subsidiaries. CMD and its subsidiaries, COS and its subsidiaries, CHK Utica, Chesapeake Granite Wash Trust and certain de minimis subsidiaries are not guarantors. See Note 18 of the notes to our consolidated financial statements 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. The indentures governing the contingent convertible senior notes do not have any financial or restricted payment covenants.

We are required to account for the liability and equity components of our convertible debt instruments separately and to reflect interest expense at the interest rate of similar nonconvertible debt at the time of issuance. These rates for our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038 are 6.86%, 8.0% and 8.0%, respectively.

COO Senior Notes

In October 2011, our wholly owned subsidiary, COO, issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. COO used the net proceeds of approximately $637 million from the placement to make a cash distribution to its direct parent, Chesapeake Oilfield Services, L.L.C., to enable it to reduce indebtedness under an intercompany note with Chesapeake. Chesapeake then used the cash distribution to reduce indebtedness under its corporate revolving bank credit facility.

The COO senior notes are the unsecured senior obligations of COO and rank equally in right of payment with all of COO's other existing and future senior unsecured indebtedness and rank senior in right of payment to all of its future subordinated indebtedness. The COO senior notes are jointly and severally, fully and unconditionally guaranteed by all of COO's wholly owned subsidiaries, other than de minimus subsidiaries. The notes may be redeemed at any time at specified make-whole or redemption prices and, prior to November 15, 2014, up to 35% of the aggregate principal amount may be redeemed in connection with certain equity offerings. Holders of the COO notes have the right to require COO to repurchase their notes upon a change of control on the terms set forth in the indenture, and COO must offer to repurchase the notes upon certain asset sales. The COO senior notes are subject to covenants that may, among other things, limit the ability of COO and its subsidiaries to make restricted payments, incur indebtedness, issue preferred stock, create liens, and consolidate, merge or transfer assets.

Conversions and Exchanges of Contingent Convertible Senior Notes and Preferred Stock

In 2010 and 2009, 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

In 2011, 2010 and 2009, shares of our cumulative convertible preferred stock were converted into shares of common stock as summarized below.

Year of Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares (in thousands)	Number of Common Shares (in thousands)
2011	5.75%	3	111
2010	5.0% (series 2005)	5	21
2009	6.25%	144	1,239
	4.125%	3	183
			1,422

Contractual Obligations and Off-balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2011, these arrangements and transactions included (i) operating lease agreements, (ii) VPP obligations (to physically deliver volumes and pay related lease operating expenses in the future), (iii) open purchase commitments, (iv) open delivery commitments, (v) open drilling commitments, (vi) undrawn letters of credit and (vii) variable interests held in VIEs. Other than described above, we have no off-balance sheet arrangements or transactions that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources.

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The table below summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2011.

	Payments Due By Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	($ in millions)				
Long-term debt:					
Principal	$ 11,087	$ —	$ 464	$ 3,014	$ 7,609
Interest	4,529	580	1,110	867	1,972
Financing lease obligations and other[(a)]	869	18	91	33	727
Operating lease obligations[(b)]	998	200	444	273	81
Asset retirement obligations[(c)]	323	5	47	12	259
Purchase obligations[(d)]	14,441	1,486	2,605	2,686	7,664
Unrecognized tax benefits[(e)]	246	—	—	246	—
Standby letters of credit	38	38	—	—	—
Other	69	13	27	7	22
Total contractual cash obligations	$ 32,600	$ 2,340	$ 4,788	$ 7,138	$ 18,334

(a) See Note 1 of the notes to our consolidated financial statements in Item 8 of this report for a description of our other long-term liabilities.

(b) See Note 4 of the notes to our consolidated financial statements in Item 8 of this report for a description of our operating lease obligations.

(c) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2011 balance sheet.

(d) 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.

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

In addition to the obligations in the table above, we enter into various commitments through the normal course of business that could potentially result in a future cash obligation that we are unable to quantify. See Note 4 of the notes to our consolidated financial statements in Item 8 of this report for further discussion. Also, see Note 13 of the notes to our consolidated financial statements in Item 8 of this report for further discussion of VIEs.

Hedging Activities

Natural Gas and Oil Derivatives

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, 2011, our natural gas and oil derivative instruments were comprised of swaps, call options, swaptions, knockout swaps and basis protection swaps. Item 7A. *Quantitative and Qualitative Disclosures About Market Ris*k contains a description of each of these instruments and realized and unrealized gains and losses on natural gas and oil derivatives during 2011, 2010 and 2009. 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 hedged 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.

The estimated fair values of our natural gas and oil derivative contracts as of December 31, 2011 and 2010 are provided below. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* of this report for additional information concerning the fair value of our natural gas and oil derivative instruments.

	December 31,	
	2011	2010
	($ in millions)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ —	$ 1,307
Natural gas call options	(284)	(701)
Natural gas put options	—	(59)
Natural gas basis protection swaps	(42)	(55)
Fixed-price oil swaps	15	(31)
Oil call options	(1,282)	(1,129)
Oil swaptions	(53)	—
Fixed-price oil knockout swaps	7	19
Estimated fair value	$ (1,639)	$ (649)

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 qualifying 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 ($162) million, ($156) million and $94 million as of December 31, 2011, 2010 and 2009, respectively. Based upon the market prices at December 31, 2011, we expect to transfer to earnings approximately $17 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 mark-to-market values) 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, 2011, 2010 and 2009 are presented in Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*, and 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 cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. 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, 2011, Chesapeake had net income of $1.742 billion, or $2.32 per diluted common share, on total revenues of $11.635 billion. This compares to net income of $1.774 billion, or $2.51 per diluted common share, on total revenues of $9.366 billion during the year ended December 31, 2010, and 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.

Natural Gas and Oil Sales. During 2011, natural gas and oil sales were $6.024 billion compared to $5.647 billion in 2010 and $5.049 billion in 2009. In 2011, Chesapeake produced and sold 1.194 tcfe of natural gas and oil at a weighted average price of $5.70 per mcfe, compared to 1.035 tcfe in 2010 at a weighted average price of $6.09 per mcfe, and 905.5 bcfe in 2009 at a weighted average price of $6.22 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized losses on derivatives of $789 million, $657 million and $588 million in 2011, 2010 and 2009, respectively). The decrease in prices in 2011 resulted in a decrease in revenue of $461 million and increased production resulted in a $968 million increase, for a total increase in revenues of $507 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.

For 2011, we realized an average price per mcf of natural gas of $4.77, compared to $5.57 in 2010 and $5.93 in 2009 (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). Included in the 2011 and 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 $63.90, $62.71 and $58.38 in 2011, 2010 and 2009, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $1.554 billion, or $1.30 per mcfe, in 2011, a net increase of $2.056 billion, or $1.99 per mcfe, in 2010 and a net increase of $2.346 billion, or $2.59 per mcfe, in 2009.

A change in natural gas and oil prices has a significant impact on our natural gas and oil revenues and cash flows. Assuming 2011 production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2011 revenues and cash flows of approximately $100 million and $97 million, respectively, and an increase or decrease of $1.00 per

barrel of oil sold would result in an increase or decrease in 2011 revenues and cash flows of approximately $32 million and $30 million, respectively, without considering the effect of hedging activities.

The following tables show our production and prices by operating division for 2011, 2010 and 2009:

	2011						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Southern[c]	554.7	2.83	1.1	39.50	561.8	47%	2.89
Northern	258.2	3.55	20.9	64.61	383.0	32	5.90
Eastern	135.8	3.27	1.5	59.79	144.8	12	3.69
Western	55.4	3.58	8.2	78.28	104.6	9	8.04
Total[d]	1,004.1	3.12	31.7	67.11	1,194.2	100%	4.40

	2010						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Southern[c]	418.7	2.98	0.8	29.91	423.4	42%	3.01
Northern	368.8	3.73	13.8	56.57	451.3	43	4.78
Eastern	74.1	3.68	0.4	51.67	76.8	7	3.85
Western	63.3	4.28	3.4	74.42	83.7	8	6.25
Total[d]	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]
Southern[c]	346.0	2.46	0.3	52.65	347.7	39%	2.50
Northern	349.3	3.60	7.8	55.24	395.6	44	4.25
Eastern	43.2	3.82	0.2	53.12	44.8	4	3.98
Western	96.3	3.77	3.5	56.82	117.4	13	4.79
Total[d]	834.8	3.16	11.8	55.60	905.5	100%	3.63

(a) Includes NGLs.

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

(c) Our Southern division primarily includes the Haynesville/Bossier Shale and the Barnett Shale which hold approximately 22% and 20% of our estimated proved reserves by volume as of December 31, 2011. Production for the Haynesville/Bossier Shale for the years ended 2011, 2010 and 2009 was 408.7 bcfe, 239.3 bcfe and 87.2 bcfe, respectively. Production for the Barnett Shale for the years ended 2011, 2010 and 2009 was 143.7 bcfe, 176.3 bcfe and 238.0 bcfe, respectively.

Our Barnett Shale production is concentrated in urban areas where the cost to develop the necessary infrastructure to gather and deliver the natural gas to intrastate pipelines significantly exceeds the cost of similar infrastructure in non-urban areas. Additionally, the rapid development of the Barnett Shale required the construction of new pipelines to provide an adequate market for these new gas reserves. In order to support the timely construction of these new pipelines, we

entered into firm transportation contracts that obligate the Company to pay demand fees even if we do not deliver specified volumes of natural gas into certain gathering systems and intrastate pipelines. The demand fees associated with unused capacity and the other gathering and transportation fees described above have resulted in lower natural gas price realizations in the Barnett Shale.

(d) 2011 period production reflects the sale of all of our Fayetteville Shale assets, which closed in March 2011 and various other asset sales, including VPP #6, VPP #7, VPP #8 and VPP #9, which closed in February 2010, June 2010, September 2010 and May 2011, respectively. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for information on divestitures.

Our average daily production of 3.272 bcfe for 2011 consisted of 2.751 bcf of natural gas (84% on a natural gas equivalent basis) and 86,784 bbls of liquids (16% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 9% and our year-over-year growth rate of liquids production was 72%. Our percentage of revenue from liquids in 2011 was 40% of unhedged natural gas and oil revenue compared to 25% in 2010 and 20% in 2009.

Marketing, Gathering and Compression Sales and Expenses. Marketing, gathering and compression sales and expenses consist of third-party revenue and expenses related to our marketing, gathering and compression operations. Marketing, gathering and compression activities are performed by Chesapeake primarily for owners in Chesapeake-operated wells. Chesapeake realized $5.090 billion in marketing, gathering and compression sales in 2011, with corresponding expenses of $4.967 billion, for a net margin before depreciation of $123 million. This compares to sales of $3.479 billion and $2.463 billion, expenses of $3.352 billion and $2.316 billion, and margins before depreciation of $127 million and $147 million in 2010 and 2009, respectively. In 2011 and 2010, Chesapeake realized an increase in marketing, gathering and compression sales and expenses primarily due to an increase in third-party marketing 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 and the sale of our Springridge natural gas gathering system and the related facilities in the Haynesville Shale to CHKM in December 2010.

Oilfield Services Revenue and Expense. Oilfield services consist of third-party revenue and expenses related to our oilfield services operations. Chesapeake recognized $521 million in oilfield services revenue in 2011 with corresponding expense of $402 million, for a net margin before depreciation of $119 million. This compares to revenue of $240 million and $190 million, expenses of $208 million and $182 million and net margins before depreciation of $32 million and $8 million in 2010 and 2009, respectively. Oilfield services margins have increased as our oilfield service business has grown in addition to an increase in service rates throughout 2010 and 2011.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $1.073 billion in 2011, compared to $893 million and $876 million in 2010 and 2009, respectively. On a unit-of-production basis, production expenses were $0.90 per mcfe in 2011 compared to $0.86 and $0.97 per mcfe in 2010 and 2009, respectively. The per unit increase in 2011 was primarily the result of the sale of our Fayetteville Shale producing wells, which were high volume wells with lower per unit costs. The per unit expense decrease in 2010 was primarily the result of completing new high volume wells with lower per unit production costs.

The following table shows our production expenses by operating division and our ad valorem tax expenses for 2011, 2010 and 2009:

	2011		2010		2009	
	Production Expenses	$/mcfe	Production Expenses	$/mcfe	Production Expenses	$/mcfe
			($ in millions, except per unit)			
Southern	$ 334	0.59	$ 262	0.62	$ 258	0.74
Northern	384	1.01	349	0.77	323	0.82
Eastern	134	0.93	117	1.52	101	2.26
Western	159	1.52	100	1.22	114	0.97
	1,011	0.85	828	0.80	796	0.88
Ad valorem tax	62	0.05	65	0.06	80	0.09
Total	$ 1,073	0.90	$ 893	0.86	$ 876	0.97

Production Taxes. Production taxes were $192 million in 2011 compared to $157 million in 2010 and $107 million in 2009. On a unit-of-production basis, production taxes were $0.16 per mcfe in 2011 compared to $0.15 per mcfe in 2010 and $0.12 per mcfe in 2009. The $35 million increase in production taxes from 2010 to 2011 is due to an increase in the average sales price of oil of $8.44 per bbl (excluding gains or losses on derivatives), and a production increase of 159 bcfe, offset by a decrease in the average sales price of natural gas of $0.31 per mcf (excluding gains or losses on derivatives). The $50 million increase in production taxes from 2009 to 2010 is due to an increase in the average sales price of natural gas and oil of $0.47 per mcfe (excluding gains or losses on derivatives), and a production increase of 130 bcfe. 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 and other property, plant and equipment (see Note 10 of the notes to our consolidated financial statements included in Item 8 of this report), were $548 million in 2011, $453 million in 2010 and $349 million in 2009. General and administrative expenses were $0.46, $0.44 and $0.38 per mcfe for 2011, 2010 and 2009, respectively. The increase in 2011 and 2010 is the result of the Company's continued growth resulting in higher payroll and associated costs. Included in general and administrative expenses is stock-based compensation of $92 million in 2011, $84 million in 2010 and $83 million in 2009. Restricted stock expense is based on the price of our common stock on the grant date of the award.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock and helps offset the fact that we do not have a pension plan. Employee restricted stock awards generally vest over a period of four 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, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, drilling and completion 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 the construction of certain of our property, plant and equipment. We capitalized $432 million, $378 million and $359 million of internal costs in 2011, 2010 and 2009, respectively, directly related to our natural gas and oil property acquisition, drilling and completion efforts and the construction of our property, plant and equipment.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas and oil properties was $1.632 billion, $1.394 billion and $1.371 billion during 2011, 2010 and 2009, 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 $1.37, $1.35 and $1.51 in 2011, 2010 and 2009, respectively. The decrease in the average rate from 2009 to 2011 is due primarily to reductions of our natural gas and oil full cost pool resulting from our divestitures in 2011, 2010 and 2009 and impairments of our full cost pool in 2009 as well as the addition of reserves through our drilling activities.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $291 million in 2011, compared to $220 million in 2010 and $244 million in 2009. The average DD&A rate per mcfe was $0.24, $0.21 and $0.27 in 2011, 2010 and 2009, respectively. The increase from 2010 to 2011 was primarily due to additional depreciation expense associated with assets acquired over the past year, offset by assets sold over the past year. The decrease from 2009 to 2010 was primarily due to certain of our midstream assets that were contributed to our midstream joint venture, CHKM, on September 30, 2009 and subsequently deconsolidated on January 1, 2010, offset by additional depreciation expense associated with the assets acquired during 2009 and 2010. 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 and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as drilling and completion costs.

(Gains) Losses on Sales and Impairments of Fixed Assets. In 2011, we recorded a ($391) million net gain associated with sales and impairments of other fixed assets, which consisted of a ($436) million gain on the sale of AMS to CHKM, a ($1) million gain related to various sales of other fixed assets and $46 million of impairments primarily related to certain of our midstream assets. In 2010, we recorded a ($116) million net gain associated with sales and impairments of other fixed assets, which consisted of a ($157) million gain on the sale of our Springridge gas gathering system to CHKM, a net $20 million loss related to various sales of other fixed assets, including the sale of pipe, gas gathering systems and other miscellaneous assets, and a $21 million impairment of midstream assets primarily related to obsolescence of certain pipe inventory. In 2009, we recorded a $168 million net loss on sales and impairments of other fixed assets, which consisted of a $38 million loss on the sale of two gathering systems and 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 oilfield services assets and $13 million of bad debt expense related to potentially uncollectible receivables.

Impairment of Natural Gas and Oil Properties. In 2009, due to lower commodity prices, we reported a non-cash impairment charge on our natural gas and oil properties of $11.0 billion. 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 derivative instruments.

Restructuring Costs. In 2009, we recorded $34 million of restructuring and relocation costs related to 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 14 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 was $44 million in 2011 compared to $19 million in 2010 and $113 million in 2009 as follows:

	Years Ended December 31,		
	2011	2010	2009
	($ in millions)		
Interest expense on senior notes	$ 653	$ 718	$ 765
Interest expense on credit facilities	70	61	60
Realized (gains) losses on interest rate derivatives	7	(14)	(23)
Unrealized (gains) losses on interest rate derivatives	7	(66)	(91)
Amortization of loan discount and other	39	36	35
Capitalized interest	(732)	(716)	(633)
Total interest expense	$ 44	$ 19	$ 113
Average long-term borrowings	$ 9,373	$ 10,345	$ 11,167

Interest expense, excluding unrealized (gains) losses on interest rate derivatives and net of amounts capitalized, was $0.03 per mcfe in 2011, $0.08 per mcfe in 2010 and $0.22 per mcfe in 2009. The decrease in interest expense per mcfe in 2011 and 2010 is due to increased production volumes, a decrease in the aggregate principal amount of our senior notes outstanding and an increase in capitalized interest. Capitalized interest increased in 2011 and 2010 as a result of a significant increase in unevaluated properties, the base on which interest is capitalized.

Earnings (Losses) on Investments. Earnings (losses) on investments was $156 million, $227 million and ($39) million in 2011, 2010 and 2009, respectively. The 2011 earnings related to our equity in the net income of certain investments, primarily CHKM and FTS International, LLC (FTS). The 2010 earnings 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 loss related to our equity in the net losses of certain investments.

Losses on Purchases or Exchanges of Debt. During 2011, we completed tender offers to purchase $1.373 billion in aggregate principal amount of certain of our senior notes and $531 million in aggregate principal amount of certain of our contingent convertible senior notes. Associated with the tender offers we recorded losses of approximately $166 million related to the senior notes and $8 million related to the contingent convertible senior notes. Also during 2011, we purchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $128 million. Associated with these purchases, we recognized a loss of $2 million in 2011.

During 2010, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, 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 a $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).

Impairment of Investments. We recorded $16 million and $162 million of impairments of certain investments in 2010 and 2009, respectively. Each of our investees was impacted by the dramatic slowing of the worldwide economy and the credit markets in 2009 and 2010. The economic weakness resulted in significantly reduced natural gas and oil prices which led 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 $23 million, $16 million and $11 million in 2011, 2010 and 2009, respectively. The 2011 income consisted of $3 million of interest income and $20 million of miscellaneous income. 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.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $1.123 billion in 2011 compared to income tax expense of $1.110 billion in 2010 and an income tax benefit of $3.483 billion in 2009. Of the $1.123 billion in income tax expense recorded in 2011, $1.110 billion is deferred. Of the $13 million increase in 2011, $14 million was the result of an increase in the effective tax rate

which was offset by a $1 million decrease as a result of the decrease in net income before income taxes. Our effective income tax rate was 39% in 2011 compared to 38.5% in 2010 and 37.5% in 2009. 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 2012.

Application of Critical Accounting Policies

Readers of this report and users of the information contained in it should be aware that certain events may impact our financial results based on the accounting policies in place. The four policies we consider to be the most significant are discussed below. The Company's management has discussed each critical accounting policy with the Audit Committee of the Company's Board of Directors.

The selection and application of accounting policies 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.

Derivatives. Chesapeake uses commodity price and financial risk management instruments to mitigate a portion of our exposure to price fluctuations in natural gas and oil prices, 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 commodity 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, or not elected 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 settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative is deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows.

Accounting guidance for derivative instruments and hedging activities establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as 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 interest rate 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. 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. Additionally, in accordance with accounting guidance for derivatives and hedging, to the extent that a legal right of set-off exists, Chesapeake nets the value of its derivative instruments with the same counterparty in the accompanying consolidated balance sheets.

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 derivative 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 derivative instruments 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, 2011, 2010 and 2009, the fair value of our derivatives were liabilities of $1.719 billion, $761 million and $63 million, respectively.

Variable Interest Entities. An entity is referred to as a VIE pursuant to accounting guidance for consolidation if it possesses one of the following criteria: (i) it is thinly capitalized, (ii) the residual equity holders do not control the entity, (iii) the equity holders are shielded from the economic losses, (iv) the equity holders do not participate fully in the entity's residual economics, or (v) the entity was established with non-substantive voting interests. We consolidate a VIE when we have both the power to direct the activities that most significantly impact the activities of the VIE and the right to receive benefits or the obligation to absorb losses of the entity that could be potentially significant to the VIE. Along with the VIEs that are consolidated in accordance with these guidelines, we also hold variable interests in other VIEs that are not consolidated because we are not the primary beneficiary. We continually monitor both consolidated and unconsolidated VIEs to determine if any events have occurred that could cause the primary beneficiary to change. See Note 13 of the notes to our consolidated financial statements in Item 8 of this report for further discussion of VIEs.

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 those of 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. 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 prior to the ending date of the quarterly period. 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. See *Natural Gas and Oil Properties* in Note 1 of the notes to our consolidated financial statements in Item 8 of this report for further information on the full cost method of accounting.

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, 2011, we had deferred tax assets of $2.323 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, 2011 and 2010, we had accrued accounts receivable from our Chief Executive Officer, Aubrey K. McClendon, of $45 million and $30 million, respectively, representing joint interest billings from December 2011 and 2010. These amounts were invoiced and timely paid in the following month. 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. From time to time, Mr. McClendon has sold his

FWPP interests in conjunction with sales by the Company of its interests in the same properties, and the proceeds related to those sales have been allocated between Mr. McClendon and the Company based on their respective ownership interests and on the same terms as those that applied to the Company's properties included in the sale.

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. 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. We are recognizing the incentive award as general and administrative expense over the five-year vesting period for the clawback resulting in an expense of approximately $15 million per year beginning in 2009. The net incentive award after deduction of applicable withholding and employment taxes 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.

In 2011, Chesapeake entered into a license and naming rights agreement with The Professional Basketball Club, LLC (PBC) for the arena in downtown Oklahoma City. The PBC is the owner of the Oklahoma City Thunder basketball team, a National Basketball Association franchise and the arena's primary tenant. Mr. McClendon has a 19.2% equity interest in PBC. Under the terms of the agreement, Chesapeake has committed to pay fees ranging from $3 million to $4 million per year through 2023 for the arena naming rights and other associated benefits. The naming rights provide Chesapeake with an enhanced public awareness and recognition both locally and nationally. Since 2008, Chesapeake has been a founding sponsor of the Oklahoma City Thunder under successive one-year contracts. In 2011, it entered into a 12-year sponsorship agreement, committing to pay an average annual fee of $3 million for advertising, use of an arena suite and other benefits. In 2011, the Company also agreed to purchase Oklahoma City Thunder game tickets for the 2011-2012 regular season home games for approximately $3 million and committed to purchase tickets for any 2012 home playoff games.

Pursuant to a court-approved litigation settlement with certain plaintiff shareholders under Litigation in Item 3 of this report, the sale of an antique map collection that occurred in December 2008 between Mr. McClendon and the Company will be rescinded. Mr. McClendon will pay the Company approximately $12 million plus interest, and the Company will reconvey the map collection to Mr. McClendon. The transaction is scheduled to be completed not later than 30 days after entry of a final non-appealable judgment.

Other Related Parties

During 2011 and 2010, our 46%-owned affiliate, 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 2011 and 2010, our transactions with CHKM included the following:

	Years Ended December 31,	
	2011	2010
	($ in millions)	
Amounts paid to CHKM:		
Gas gathering fees[(a)]	$ 469	$ 378
Amounts received from CHKM:		
Compressor rentals	60	48
Inventory purchases	93	47
Other services provided	91	73
Total amounts received from CHKM	$ 244	$ 168

(a) Other working interest and royalty owners are charged their proportionate share of the gas gathering fees.

As of December 31, 2011 and 2010, we had net receivables (payables) from (to) CHKM of $2 million and ($45) million, respectively. In addition, in 2011 and 2010, we sold natural gas gathering systems and related equipment to CHKM. See Note 11 of the notes to our consolidated financial statements in Item 8 of this report for further discussion.

During 2011, 2010 and 2009, our 30%-owned affiliate, FTS, provided us pressure pumping and other services in the ordinary course of business. During 2011, 2010 and 2009, we paid FTS $369 million, $89 million and $43 million, respectively, for these services. As of December 31, 2011, 2010 and 2009, we had $115 million, $30 million and $8 million, respectively, due FTS 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 December 2011, the FASB issued guidance on disclosure of information about offsetting and related arrangements to enable users of a company's financial statements to understand the effect of those arrangements on its financial position. The standard is effective for annual reporting periods beginning on or after January 1, 2013. This guidance will not have an impact on our financial position or results of operations.

In September 2011, the FASB issued guidance related to the annual goodwill impairment test. The guidance provides entities with the option of performing a qualitative assessment to determine whether the two-step goodwill impairment test is necessary. The revised standard is effective for goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We do not expect this guidance to have a material effect on our financial condition or results of operations as it is a change in application of the goodwill impairment test only.

In June 2011, the FASB issued guidance on comprehensive income, which provides two options for presenting items of net income, comprehensive income and total comprehensive income, by either

creating one continuous statement of comprehensive income or two separate consecutive statements. We adopted this guidance in 2011. Adoption had no impact on our financial position or results of operations. In December 2011, the FASB deferred the effective date of certain presentation requirements for items reclassified out of accumulated other comprehensive income. This guidance will not have an impact on our financial position or results of operations.

In May 2011, the FASB issued guidance which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value under GAAP and International Financial Reporting Standards (IFRS). This new guidance changes some fair value measurement principles and disclosure requirements. We will have additional disclosures around our Level 3 financial instruments that are reported at fair value, and we will categorize the level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. This guidance is effective January 1, 2012. The guidance will not have an impact on our financial position or results of operations.

In 2010, the FASB issued guidance requiring additional disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method effective beginning on January 1, 2011. We adopted this guidance in 2011. Adoption had no impact on our financial position or results of operations. See Note 15 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 as amended (the "Exchange Act"). 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 drilling activity and drilling and completion capital expenditures, and anticipated asset monetizations, 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 fund capital expenditures, 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;

- our ability 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, the need to secure hedging liabilities and the ability of counterparties to satisfy their obligations to us;
- 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;
- oilfield services shortages, pipeline and gathering system capacity constraints and transportation interruptions that could adversely affect our cash flow; and
- losses possible from pending or future litigation.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this report and our other filings with the Securities and Exchange Commission (SEC) 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 Derivatives

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. 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 higher 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 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 (calls and swaptions). 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. We do this when we would be satisfied to sell our production at the price being capped by the call strike price or believe it would 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. In the second half of 2011, we bought natural gas calls to, in effect, lock in sold call positions. Due to the low natural gas prices, we were able to achieve this at a low cost to us. We deferred the payment of the premium on these trades to the related month of production being hedged. At times, we have taken advantage of attractive strip prices in out-years and sold natural gas and oil call options to our counterparties in

exchange for near-term natural gas swaps with fixed prices above the then current market price. This effectively allows 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. In the fourth quarter of 2011, we entered into oil swaps that can be extended at the option of the counterparty. This allows us to receive a higher fixed price on these swaps than what the market would have offered without such an option. Some of our derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception and the cash settlements associated with these instruments are classified as financing cash flows in the accompanying consolidated statement of cash flows.

We determine the volume we may potentially hedge by reviewing our 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 derivative instruments are already executed for some volume above the new production forecasts, the positions are reversed. The actual fixed 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 are at 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 trade that effectively reverses the current position. 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.

We have determined 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. Future risk related to counterparties not being able to meet their obligations has been partially mitigated under our secured hedging facility which requires counterparties to post collateral if their obligations to Chesapeake are in excess of defined thresholds. 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. See Note 15 of the notes to our consolidated financial statements in Item 8 of this report for further discussion of the fair value measurements associated with our derivatives.

As of December 31, 2011, 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 and, occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call

option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call options, no payment is due from either party.

- *Swaptions:* Chesapeake sells swaptions to counterparties that allow them, on a specific date, to extend an existing fixed-price swap for a certain period of time.
- *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 a certain pre-determined knockout price.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. Our basis protection swaps 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.

As of December 31, 2011, we had the following open natural gas and oil derivative instruments:

		Weighted Average Price				Cash Flow	Fair
	Volume	Fixed	Put	Call	Differential	Hedge	Value
Natural Gas:	(tbtu)			(per mmbtu)			($ in millions)
Call Options (sold):							
2012	370	$ —	$ —	$ 7.36	$ —	No	$ (1)
2013	415	—	—	6.44	—	No	(23)
2014	330	—	—	6.43	—	No	(40)
2015	226	—	—	6.31	—	No	(54)
2016	279	—	—	6.72	—	No	(99)
2017 – 2020	114	—	—	10.92	—	No	(27)
Call Options (bought)[a]:							
2012	(223)	—	—	7.90	—	No	—
2015	(110)	—	—	6.16	—	No	(30)
2016	(44)	—	—	6.00	—	No	(10)
Basis Protection Swaps:							
Q1 2012	2	—	—	—	(0.35)	No	(1)
Q2 2012	20	—	—	—	(0.81)	No	(13)
Q3 2012	21	—	—	—	(0.80)	No	(12)
Q4 2012	8	—	—	—	(0.74)	No	(4)
2013 – 2018	55	—	—	—	(0.48)	No	(12)
Total Natural Gas							$ (326)

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		Weighted Average Price				Cash Flow	Fair
	Volume	Fixed	Put	Call	Differential	Hedge	Value
Oil:	(mmbbl)			(per bbl)			($ in millions)
Non-Qualified Swaps:							
Q1 2012	4.6	$ 101.15	$ —	$ —	$ —	No	$ 9
Q2 2012	4.6	101.82	—	—	—	No	11
Q3 2012	2.1	100.93	—	—	—	No	4
Q4 2012	1.7	99.55	—	—	—	No	1
2013	0.7	87.69	—	—	—	No	(6)
2014	0.7	88.27	—	—	—	No	(3)
2015	0.5	88.75	—	—	—	No	(1)
Call Options (sold)[(b)]:							
Q1 2012	4.1	—	—	93.03	—	No	(23)
Q2 2012	4.0	—	—	93.03	—	No	(38)
Q3 2012	4.1	—	—	93.03	—	No	(45)
Q4 2012	4.1	—	—	93.03	—	No	(49)
2013	19.4	—	—	94.74	—	No	(285)
2014	15.4	—	—	96.61	—	No	(214)
2015	19.4	—	—	100.57	—	No	(264)
2016	18.9	—	—	104.71	—	No	(249)
2017	5.3	—	—	83.50	—	No	(115)
Swaptions:							
Q3 2012	1.8	106.38	—	—	—	No	(11)
Q4 2012	2.3	106.45	—	—	—	No	(13)
2013	3.7	102.88	—	—	—	No	(29)
Knock-Out Swaps:							
Q1 2012	0.2	109.50	60.00	—	—	No	2
Q2 2012	0.2	109.50	60.00	—	—	No	2
Q3 2012	0.2	109.50	60.00	—	—	No	2
Q4 2012	0.2	109.50	60.00	—	—	No	1
Total Oil							$ (1,313)
Total Natural Gas and Oil							$ (1,639)

(a) Included in the fair value are deferred premiums of $59 million and $28 million which we will pay in 2015 and 2016, respectively.

(b) Included in oil call options are NGL call options in the amount of 5,000 bbls per day at $38.01 per bbl for 2012.

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In addition to the open derivative positions disclosed above, at December 31, 2011, we had $352 million of net hedging gains related to settled trades for future production periods that will be recorded within natural gas and oil sales as realized gains (losses) as they are transferred from either accumulated other comprehensive income or unrealized gains (losses) in the month of related production based on the terms specified in the original contract as noted below.

	December 31, 2011
	($ in millions)
Q1 2012	$ 139
Q2 2012	170
Q3 2012	3
Q4 2012	(17)
2013	47
2014	(191)
2015	165
2016	21
2017 – 2022	15
Total	$ 352

The table below reconciles the changes in fair value of our natural gas and oil derivatives during the years ended December 31, 2011, 2010 and 2009. Of the $1.639 billion fair value liability as of December 31, 2011, ($178) million related to contracts maturing in the next 12 months and ($1.461) billion related to contracts maturing after 12 months. All transactions hedged as of December 31, 2011 are expected to mature by December 31, 2022.

	2011	2010	2009
		($ in millions)	
Fair value of contracts outstanding, as of January 1	$ (649)	$ 21	$ 1,305
Change in fair value of contracts	664	995	1,266
Fair value of new contracts when entered into	(347)	(581)	(21)
Contracts realized or otherwise settled	(478)	(1,691)	(2,102)
Fair value of contracts when closed	(829)	607	(427)
Fair value of contracts outstanding, as of December 31	$ (1,639)	$ (649)	$ 21

The change in natural gas and oil prices during the year ended December 31, 2011 decreased the value of our derivative liabilities by $664 million. This gain is recorded in natural gas and oil sales or in accumulated other comprehensive income. We entered into new contracts which were in a liability position of $347 million. We settled contracts for a gain of $478 million and we terminated contracts that were in an asset position of $829 million. The realized gain is recorded in natural gas and oil sales in the month of related production.

Pursuant to accounting guidance for derivatives and hedging, certain derivatives qualify for designation as cash flow hedges. Following these provisions, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). Realized gains (losses) consist of settled contracts related to the production periods being reported. Unrealized gains (losses) consist of both temporary fluctuations in the mark-to-market values of non-qualifying contracts and settled values of non-qualifying derivatives related to future production periods.

The components of natural gas and oil sales for the years ended December 31, 2011, 2010 and 2009 are presented below.

	Years Ended December 31,		
	2011	2010	2009
	($ in millions)		
Natural gas and oil sales	$ 5,259	$ 4,248	$ 3,291
Realized gains (losses) on natural gas and oil derivatives	1,554	2,056	2,346
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(782)	(634)	(624)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(7)	(23)	36
Total natural gas and oil sales	$ 6,024	$ 5,647	$ 5,049

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates.

	Years of Maturity						
	2012	2013	2014	2015	2016	Thereafter	Total
	($ in millions)						
Liabilities:							
Long-term debt – fixed rate[(a)]	$ —	$ 464	$ —	$ 1,265	$ —	$ 7,609	$ 9,338
Average interest rate	—	7.63%	—	9.50%	—	5.58%	6.21%
Long-term debt – variable rate	$ —	$ —	$ —	$ 1,719	$ 30	$ —	$ 1,749
Average interest rate	—	—	—	2.03%	2.83%	—	2.04%

(a) This amount does not include the discount included in long-term debt of ($490) million and interest rate derivatives of $28 million.

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

Interest Rate Derivatives

To mitigate a portion of our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives. As of December 31, 2011, our interest rate derivative instruments consisted of the following types of instruments:

- *Swaps*: Chesapeake enters into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and a pay fixed interest rate) to manage our interest rate exposure related to our bank credit facility borrowings.
- *Swaptions*: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a swap with us on a specific date.

As of December 31, 2011, the following interest rate derivatives were outstanding:

	Notional Amount	Weighted Average Rate Fixed	Weighted Average Rate Floating[(a)]	Fair Value Hedge	Net Premiums	Fair Value
	($ in millions)				($ in millions)	
Fixed to Floating:						
Swaption						
Q1 2012	$ 300	6.13%	3 ml plus 340 bp	No	$ 2	$ —
Floating to Fixed:						
Swaps						
Mature 2014 – 2015	$ 1,050	2.13%	1 – 6 mL	No	—	(42)
					$ 2	$ (42)

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

In addition to open derivative positions disclosed above, at December 31, 2011 we had $81 million of net hedging gains related to settled contracts that will be recorded within interest expense as realized gains (losses) as they are transferred from either our senior note liability or unrealized interest expense gains (losses) over the next nine-year term of the related senior notes. In conjunction with our May 2011 tender offers, we transferred $18 million of the gain to loss on redemption of debt.

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. The components of interest expense for the years ended December 31, 2011, 2010 and 2009 are presented below.

	Years Ended December 31, 2011	2010	2009
		($ in millions)	
Interest expense on senior notes	$ 653	$ 718	$ 765
Interest expense on credit facilities	70	61	60
Realized (gains) losses on interest rate derivatives	7	(14)	(23)
Unrealized (gains) losses on interest rate derivatives	7	(66)	(91)
Amortization of loan discount and other	39	36	35
Capitalized interest	(732)	(716)	(633)
Total interest expense	$ 44	$ 19	$ 113

Foreign Currency Derivatives

In December 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 cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. As a result, we reclassified a loss of $38 million from accumulated other comprehensive income to the consolidated statement of operations, $20 million of which related to the unwound notional amount and was included in losses on purchases or exchanges of debt, and $18 million of which related to future interest associated with the unwound principal and was included in interest expense. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay Chesapeake €11 million and Chesapeake pays the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%.

Upon maturity of the notes, the counterparties will pay Chesapeake €344 million and Chesapeake will pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swaps, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swaps qualify as cash flow hedges. The fair values of the cross currency swaps are recorded on the consolidated balance sheet as a liability of $38 million at December 31, 2011. The euro-denominated debt in long-term debt has been adjusted to $446 million at December 31, 2011 using an exchange rate of $1.2973 to €1.00.

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

INDEX TO FINANCIAL STATEMENTS
CHESAPEAKE ENERGY CORPORATION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management has performed an assessment of the effectiveness of the Company's internal control over financial reporting and has determined the Company's internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

/s/ AUBREY K. MCCLENDON
Aubrey K. McClendon
Chairman of the Board and Chief Executive Officer
/s/ DOMENIC J. DELL'OSSO, JR.
Domenic J. Dell'Osso, Jr.
Executive Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries (the "Company") at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for variable interest entities as of January 1, 2010. Also as discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it estimates the quantities of oil and gas reserves in 2009 and the limitation on its capitalized costs as of December 31, 2009.

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

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

/s/ PricewaterhouseCoopers LLP
Tulsa, Oklahoma

February 29, 2012

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $0 attributable to our VIE)	$ 351	$ 102
Restricted cash	44	—
Accounts receivable	2,505	1,974
Short-term derivative assets	13	947
Deferred income tax asset	139	139
Other current assets	125	104
Total Current Assets	3,177	3,266
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full cost accounting:		
Evaluated natural gas and oil properties ($498 and $0 attributable to our VIE)	41,723	38,952
Unevaluated properties	16,685	14,469
Natural gas gathering systems and treating plants	1,763	1,545
Oilfield services equipment	1,498	921
Other property and equipment	3,360	2,805
Total Property and Equipment, at Cost	65,029	58,692
Less: accumulated depreciation, depletion and amortization (($6) and $0 attributable to our VIE)	(28,290)	(26,314)
Total Property and Equipment, Net	36,739	32,378
LONG-TERM ASSETS:		
Investments	1,531	1,208
Other long-term assets	388	327
TOTAL ASSETS	$ 41,835	$ 37,179
CURRENT LIABILITIES:		
Accounts payable	$ 3,311	$ 2,069
Short-term derivative liabilities ($9 and $0 attributable to our VIE)	191	15
Accrued interest	183	191
Other current liabilities ($23 and $0 attributable to our VIE)	3,397	2,215
Total Current Liabilities	7,082	4,490
LONG-TERM LIABILITIES:		
Long-term debt, net	10,626	12,640
Deferred income tax liabilities	3,484	2,384
Long-term derivative liabilities ($10 and $0 attributable to our VIE)	1,541	1,693
Asset retirement obligations	323	301
Other long-term liabilities	818	407
Total Long-Term Liabilities	16,792	17,425
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized:		
7,251,515 and 7,254,515 shares outstanding	3,062	3,065
Common stock, $0.01 par value, 1,000,000,000 shares authorized:		
660,888,159 and 655,251,275 shares issued	7	7
Paid-in capital	12,146	12,194
Retained earnings	1,608	190
Accumulated other comprehensive income (loss)	(166)	(168)
Less: treasury stock, at cost; 1,552,533 and 1,221,299 common shares	(33)	(24)
Total Chesapeake Stockholders' Equity	16,624	15,264
Noncontrolling interests	1,337	—
Total Equity	17,961	15,264
TOTAL LIABILITIES AND EQUITY	$ 41,835	$ 37,179

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2011	2010	2009
	($ in millions, except per share data)		
REVENUES:			
Natural gas and oil	$ 6,024	$ 5,647	$ 5,049
Marketing, gathering and compression	5,090	3,479	2,463
Oilfield services	521	240	190
Total Revenues	11,635	9,366	7,702
OPERATING EXPENSES:			
Natural gas and oil production	1,073	893	876
Production taxes	192	157	107
Marketing, gathering and compression	4,967	3,352	2,316
Oilfield services	402	208	182
General and administrative	548	453	349
Natural gas and oil depreciation, depletion and amortization	1,632	1,394	1,371
Depreciation and amortization of other assets	291	220	244
(Gains) losses on sales and impairments of fixed assets	(391)	(116)	168
Impairment of natural gas and oil properties	—	—	11,000
Restructuring	—	—	34
Total Operating Expenses	8,714	6,561	16,647
INCOME (LOSS) FROM OPERATIONS	2,921	2,805	(8,945)
OTHER INCOME (EXPENSE):			
Interest expense	(44)	(19)	(113)
Earnings (losses) on investments	156	227	(39)
Losses on purchases or exchanges of debt	(176)	(129)	(40)
Impairments of investments	—	(16)	(162)
Other income	23	16	11
Total Other Income (Expense)	(41)	79	(343)
INCOME (LOSS) BEFORE INCOME TAXES	2,880	2,884	(9,288)
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	13	—	4
Deferred income taxes	1,110	1,110	(3,487)
Total Income Tax Expense (Benefit)	1,123	1,110	(3,483)
NET INCOME (LOSS)	1,757	1,774	(5,805)
Net income attributable to noncontrolling interests	(15)	—	(25)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,742	1,774	(5,830)
Preferred stock dividends	(172)	(111)	(23)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 1,570	$ 1,663	$ (5,853)
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ 2.47	$ 2.63	$ (9.57)
Diluted	$ 2.32	$ 2.51	$ (9.57)
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.3375	$ 0.30	$ 0.30
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	637	631	612
Diluted	752	706	612

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2011	2010	2009
	($ in millions)		
Net income (loss)	$ 1,757	$ 1,774	$ (5,805)
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of $137 million, $129 million and $413 million	224	212	677
Reclassification of (gain) loss on settled derivative instruments, net of income taxes of ($139) million, ($298) million and ($540) million	(225)	(491)	(885)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $3 million, $9 million and ($14) million	4	14	(23)
Unrealized (gain) loss on available-for-sale securities, net of income taxes of ($1) million, ($3) million and $14 million	(1)	(5)	23
Reclassification of loss on investments, net of income taxes of $0, $0 and $26 million	—	—	43
Other comprehensive income (loss)	2	(270)	(165)
Comprehensive income (loss)	1,759	1,504	(5,970)
Net income attributable to noncontrolling interests	(15)	—	(25)
Comprehensive income (loss) available to Chesapeake	$ 1,744	$ 1,504	$ (5,995)

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2011	2010	2009
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ 1,757	$ 1,774	$ (5,805)
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	1,923	1,614	1,615
Deferred income tax expense (benefit)	1,110	1,110	(3,487)
Unrealized losses on derivatives	796	592	497
Stock-based compensation	153	147	140
Accretion of discount on contingent convertible notes	—	78	79
(Gains) losses or impairments on sales of other property and equipment	(391)	(116)	168
(Gains) losses on investments	(41)	(107)	39
Losses on purchases or exchanges of debt	5	29	40
Impairment of natural gas and oil properties	—	—	11,000
Impairment of investments	—	16	162
Other	(3)	32	39
Increase in accounts receivable and other assets	(530)	(769)	(31)
Increase (decrease) in accounts payable, accrued liabilities and other	1,124	717	(100)
Cash provided by operating activities	5,903	5,117	4,356
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and completion costs on proved and unproved properties	(7,467)	(5,242)	(3,572)
Acquisition of proved and unproved properties	(4,974)	(6,945)	(2,268)
Proceeds from divestitures of proved and unproved properties	7,651	4,292	1,926
Additions to other property and equipment	(2,009)	(1,326)	(1,683)
Proceeds from sales of other assets	1,312	883	176
Proceeds from (additions to) investments	101	(134)	(40)
Acquisition of drilling company	(339)	—	—
Increase in restricted cash	(44)	—	—
Other	(43)	(31)	(1)
Cash used in investing activities	(5,812)	(8,503)	(5,462)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from credit facilities borrowings	15,509	15,117	7,761
Payments on credit facilities borrowings	(17,466)	(13,303)	(9,758)
Proceeds from issuance of senior notes, net of offering costs	1,614	1,967	1,346
Proceeds from issuance of preferred stock, net of offering costs	—	2,562	—
Cash paid to purchase debt	(2,015)	(3,434)	—
Cash paid for common stock dividends	(207)	(189)	(181)
Cash paid for preferred stock dividends	(172)	(92)	(23)
Cash received on financing derivatives	1,043	621	109
Proceeds from sale of noncontrolling interests	1,348	—	588
Proceeds from other financings	300	—	199
Distributions to noncontrolling interests	(9)	—	(10)
Net increase (decrease) in outstanding payments in excess of cash balance	353	20	(249)
Other	(140)	(88)	(118)
Cash provided by (used in) financing activities	158	3,181	(336)
Net increase (decrease) in cash and cash equivalents	249	(205)	(1,442)
Cash and cash equivalents, beginning of period	102	307	1,749
Cash and cash equivalents, end of period	$ 351	$ 102	$ 307

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

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

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF NET CASH PAYMENTS (REFUNDS) FOR:

	Years Ended December 31,		
	2011	2010	2009
		($ in millions)	
Interest, net of capitalized interest	$ —	$ 11	$ 64
Income taxes, net of refunds received	$ (25)	$ (291)	$ 7

SUPPLEMENTAL SCHEDULE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of December 31, 2011, 2010 and 2009, dividends payable on our common and preferred stock were $99 million, $90 million and $53 million, respectively.

In 2011, 2010 and 2009, natural gas and oil properties were adjusted by $176 million, $161 million and ($93) million, respectively, as a result of an increase (decrease) in accrued acquisition, drilling and completion costs.

In 2011, 2010 and 2009, other property and equipment were adjusted by $64 million, ($19) million and ($55) million, respectively, as a result in an increase (decrease) in accrued costs.

As of December 31, 2011, 2010 and 2009, we had recorded $81 million, $371 million and $244 million, respectively, of various liabilities related to the purchase of proved and unproved properties and other assets.

In 2011, we sold a wholly owned midstream subsidiary to our 46% owned affiliate, Chesapeake Midstream Partners, L.P. (CHKM), for total consideration of $879 million, including cash of $600 million and 9,791,605 common units of CHKM that had a value at closing of $279 million. See Note 11 for further discussion of this transaction.

In 2009, we issued 24,822,832 shares of common stock, valued at $429 million, for the purchase of proved and unproved properties pursuant to an acquisition shelf registration statement.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY

	Years Ended December 31,		
	2011	2010	2009
	($ in millions, except per share data)		
PREFERRED STOCK:			
Balance, beginning of period	$ 3,065	$ 466	$ 505
Issuance of 0, 1,500,000 and 0 shares of 5.75% preferred stock	—	1,500	—
Issuance of 0, 1,100,000 and 0 shares of 5.75% preferred stock (series A)	—	1,100	—
Conversion of 3,000, 5,000 and 146,801 shares of preferred stock for common stock	(3)	(1)	(39)
Balance, end of period	3,062	3,065	466
COMMON STOCK:			
Balance, beginning of period	7	6	6
Exchange of convertible notes for 0, 298,500 and 10,210,169 shares of common stock	—	—	—
Conversion of preferred stock for 111,111, 20,774 and 1,422,425 shares of common stock	—	—	—
Issuance of 0, 0 and 24,822,832 shares of common stock for the purchase of proved and unproved properties	—	—	—
Stock-based compensation	—	1	—
Balance, end of period	7	7	6
PAID-IN CAPITAL:			
Balance, beginning of period	12,194	12,146	11,680
Stock-based compensation	171	226	199
Purchase of contingent convertible notes	(123)	—	—
Issuance of 0, 0 and 24,822,832 shares of common stock for the purchase of proved and unproved properties	—	—	421
Exchange of convertible notes for 0, 298,500 and 10,210,169 shares of common stock	—	8	262
Conversion of preferred stock for 111,111, 20,774 and 1,422,425 shares of common stock	3	1	39
Offering/transaction expenses	(12)	(38)	(16)
Reduction in tax benefit from stock-based compensation	(26)	(13)	(48)
Dividends on common stock	(48)	(95)	(185)
Dividends on preferred stock	(15)	(44)	(22)
Exercise of stock options	2	3	4
Allocation of joint venture capital to Global Infrastructure Partners	—	—	(294)
Tax effect on equalization of partners' capital	—	—	106
Balance, end of period	12,146	12,194	12,146

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY – (Continued)

	Years Ended December 31,		
	2011	2010	2009
	($ in millions, except per share data)		
RETAINED EARNINGS (DEFICIT):			
Balance, beginning of period	$ 190	$ (1,261)	$ 4,569
Net income (loss) attributable to Chesapeake	1,742	1,774	(5,830)
Cumulative effect of accounting change, net of income taxes of $0, $89 million and $0	—	(142)	—
Dividends on common stock	(168)	(95)	—
Dividends on preferred stock	(156)	(86)	—
Balance, end of period	1,608	190	(1,261)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(168)	102	267
Hedging activity	3	(265)	(231)
Investment activity	(1)	(5)	66
Balance, end of period	(166)	(168)	102
TREASURY STOCK – COMMON:			
Balance, beginning of period	(24)	(15)	(10)
Purchase of 425,140, 351,163 and 227,827 shares for company benefit plans	(11)	(9)	(5)
Release of 93,906, 7,069 and 7,898 shares for company benefit plans	2	—	—
Balance, end of period	(33)	(24)	(15)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	16,624	15,264	11,444
NONCONTROLLING INTERESTS:			
Balance, beginning of period	—	897	—
Sales of noncontrolling interests	1,340	—	588
Allocation of joint venture capital to Global Infrastructure Partners	—	—	294
Net income attributable to noncontrolling interests	15	—	25
Distributions to noncontrolling interest owners	(18)	—	(10)
Deconsolidation of investment in Chesapeake Midstream Partners	—	(897)	—
Balance, end of period	1,337	—	897
TOTAL EQUITY	$ 17,961	$ 15,264	$ 12,341

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation ("Chesapeake" or the "Company") is a natural gas and oil exploration and production company engaged in the exploration, development and acquisition of properties for the production of natural gas and oil from underground reservoirs. We also provide substantial marketing, midstream, drilling and other oilfield services. Our operations are located onshore and in the continental United States.

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake holds a controlling interest. Chesapeake consolidates subsidiaries in which it holds, directly or indirectly, more than 50% of the voting rights and variable interest entities (VIEs) in which Chesapeake is the primary beneficiary. We use the equity method of accounting to record our net interests in VIEs where we are not the primary beneficiary and, in entities not deemed to be VIEs, where Chesapeake holds 20% to 50% of the voting rights and/or has the ability to exercise significant influence. Under the equity method, our share of net income (loss) is included in our consolidated statements of operations according to our equity ownership or according to the terms of the applicable governing instrument. Investments in securities not accounted for under the equity method have been designated as available-for-sale and, as such, are carried at fair value whenever this value is readily determinable. Otherwise, the investment is carried at cost. See Note 12 for further discussion of investments. All significant intercompany accounts and transactions have been eliminated. Undivided interests in natural gas and oil exploration and production joint ventures are consolidated on a proportionate basis.

Variable Interest Entities

An entity is referred to as a VIE pursuant to accounting guidance for consolidation if it possesses one of the following criteria: (i) it is thinly capitalized, (ii) the residual equity holders do not control the entity, (iii) the equity holders are shielded from the economic losses, (iv) the equity holders do not participate fully in the entity's residual economics, or (v) the entity was established with non-substantive voting interests. We consolidate a VIE when we have both the power to direct the activities that most significantly impact the activities of the VIE and the right to receive benefits or the obligation to absorb losses of the entity that could be potentially significant to the VIE. Along with the VIEs that are consolidated in accordance with these guidelines, we also hold variable interests in other VIEs that are not consolidated because we are not the primary beneficiary. We continually monitor both consolidated and unconsolidated VIEs to determine if any events have occurred that could cause the primary beneficiary to change. See Note 13 for further discussion of VIEs.

Cumulative Effect of Accounting Change

Effective January 1, 2010, in accordance with new authoritative guidance for VIEs, we ceased consolidating our midstream joint venture within our financial statements and began to account for the joint venture under the equity method (see Note 12). Adoption of this new guidance resulted in an after-tax cumulative effect charge to retained earnings of $142 million, which is reflected in our consolidated statement of equity for the year ended December 31, 2010. This charge reflects the difference between the carrying value of our initial investment in the joint venture, which was recorded at carryover basis as an entity under common control, and the fair value of our equity in the joint venture as of the formation date. See Note 13 for further discussion of VIEs.

Accounting Estimates

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

Estimates of natural gas and oil reserves and their values, future production rates and future costs and expenses are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions may be material and could materially affect our financial statements. The volatility of commodity prices, including the further decline of U.S. natural gas prices, results in increased uncertainty inherent in such estimates and assumptions. A further decline in natural gas prices or a significant decline in oil prices could result in actual results differing significantly from our estimates.

Risks and Uncertainties

Approximately 83% of our estimated proved reserves volumes as of December 31, 2011 were natural gas and 84% of our 2011 natural gas and oil sales volumes were natural gas. Although we are shifting our strategy to a more liquids-heavy portfolio, having 40% of our natural gas and oil revenue before the effects of hedging derived from liquids production in 2011, and curtailing drilling operations and production in our dry gas plays due to low natural gas prices, we have a material exposure to those low prices. While our derivative arrangements serve to mitigate a portion of the effect of price volatility on our cash flows, our forecasted natural gas production is currently not protected against downward price adjustments by derivative instruments and our use of crude oil derivatives to partially mitigate the price risk of our liquids production is subject to basis risk to the extent oil and natural gas liquids prices do not remain highly correlated. Sustained low natural gas prices, and volatile commodity prices in general, could have a material adverse effect on our financial position, results of operations and cash flows, which could adversely impact our ability to comply with financial covenants under our credit facilities and further limit our ability to fund our planned capital expenditures. In addition, sustained low commodity prices could result in a reduction in the estimated quantity of proved reserves we report and in the estimated future net cash flows expected to be generated from reserves that may require us to write down the carrying value of our natural gas and oil properties, and such amounts could be material.

Cash and Cash Equivalents and Restricted Cash

For purposes of the consolidated financial statements, Chesapeake considers investments in all highly liquid instruments with original maturities of three months or less at date of purchase to be cash equivalents. Restricted cash consists of a minimum cash balance equal to two quarterly dividend payments as required by our CHK Utica financial transaction. See Note 8 for further discussion.

Accounts Receivable

Our accounts receivable are primarily from purchasers of natural gas and oil and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our

customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of all our counterparties and 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 2011 and 2010, we recognized nominal amounts and during 2009, we recognized $13 million of bad debt expense related to potentially uncollectible receivables. Accounts receivable as of December 31, 2011 and 2010 are detailed below.

	December 31,	
	2011	2010
	($ in millions)	
Natural gas and oil sales	$ 1,089	$ 821
Joint interest	1,171	977
Oilfield services	43	10
Related parties[(a)]	45	30
Other	176	154
Allowance for doubtful accounts	(19)	(18)
Total accounts receivable	$ 2,505	$ 1,974

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

Natural Gas and Oil Properties

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 (see Note 10). Capitalized costs are amortized on a composite unit-of-production method based on proved natural gas and oil reserves. Estimates of our proved reserves as of December 31, 2011 were prepared by both third-party engineering firms and Chesapeake's internal staff. Approximately 77% of these proved reserves estimates (by volume) at December 31, 2011 were prepared by independent engineering firms. In addition, our internal engineers review and update our reserves on a quarterly basis. The average composite rates used for depreciation, depletion and amortization of natural gas and oil properties were $1.37 per mcfe in 2011, $1.35 per mcfe in 2010 and $1.51 per mcfe in 2009.

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 prospect area where individual property costs are not significant and are assessed individually when individual costs are significant.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2011 and notes the year in which the associated costs were incurred.

	Year of Acquisition				
	2011	2010	2009	Prior	Total
			($ in millions)		
Leasehold acquisition cost	$ 3,452	$ 5,161	$ 1,086	$ 3,562	$ 13,261
Exploration cost	1,638	73	—	30	1,741
Capitalized interest	642	472	137	432	1,683
Total	$ 5,732	$ 5,706	$ 1,223	$ 4,024	$ 16,685

We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the Securities and Exchange Commission (SEC) on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating 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 prior to the ending date of the quarterly period. 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. Cash flow hedges locked in prior to December 31, 2011 which relate to future production periods decreased the full cost ceiling by $250 million. As of December 31, 2011, none of our open derivative instruments were qualified as cash flow hedges. Our natural gas and oil hedging activities are discussed in Note 9 of these consolidated financial statements.

Two primary factors impacting the ceiling test are reserves 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 extended 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 written off as an expense.

Through September 30, 2009, all proved natural gas and oil reserve volumes were prepared using previous SEC reserve requirements that are not comparable to the SEC's Modernization Rules which are applicable for quarterly periods ending subsequent to September 30, 2009. In addition, for purposes of determining future net revenues for our ceiling test, our net proved natural gas and oil reserves would have been calculated through September 30, 2009 using end of period commodity prices rather than using the unweighted arithmetic average of natural gas and oil prices on the first day of each month within the preceding 12-month period. These factors impact the calculation of our unit-of-production depletion expense and our quarterly ceiling tests, which therefore affects the comparability of our financial statements between periods presented.

We account for seismic costs in accordance with Rule 4-10 of Regulation S-X. Specifically, Rule 4-10 requires that all companies that use the full cost method capitalize exploration costs as part of their natural gas and oil properties (i.e., full cost pool). Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Further, exploration costs include, among other things, geological and geophysical studies and salaries and other expenses of geologists,

geophysical crews and others conducting those studies. Such costs are capitalized as incurred. Seismic costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties. The Company reviews its unproved properties and associated seismic costs quarterly in order to ascertain whether impairment has occurred. To the extent that seismic costs cannot be directly associated with specific unevaluated properties, they are included in the amortization base as incurred.

Other Property and Equipment

Other property and equipment consists primarily of natural gas gathering systems and treating plants, oilfield services equipment, including drilling rigs, rental tools, pressure pumping and mining equipment, natural gas compressors, land, buildings and improvements, vehicles and office equipment. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. The costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from the accounts, and the resulting gain or loss is reflected in operating costs. Other property and equipment costs, excluding land, are depreciated on a straight-line basis. A summary of other property and equipment and the useful lives is as follows:

	December 31,		Useful
	2011	2010	Life
	($ in millions)		(in years)
Natural gas gathering systems and treating plants	$ 1,763	$ 1,545	20
Oilfield services equipment	1,498	921	3 – 15
Buildings and improvements	1,202	917	10 – 39
Natural gas compressors	303	304	20
Land	926	896	—
Other	929	688	2 – 7
Total other property and equipment, at cost	6,621	5,271	
Less: accumulated depreciation and amortization	(1,082)	(720)	
Total other property and equipment, net	$ 5,539	$ 4,551	

Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value, if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. For 2011 and 2010, we recorded impairments of $46 million and $21 million, respectively, primarily to midstream assets. For 2009, we recorded an impairment of $86 million associated with certain of our midstream assets and $27 million associated with certain of our oilfield services assets.

Noncontrolling Interests

Noncontrolling interests represent third-party equity ownership in certain of our consolidated subsidiaries or our VIE and are presented as a component of equity. See Note 8 for further discussion of noncontrolling interests.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Capitalized Interest

During 2011, 2010 and 2009, interest of approximately $727 million, $711 million and $627 million, respectively, was capitalized on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Additional interest of $6 million, $5 million and $6 million was capitalized in 2011, 2010 and 2009, respectively, on midstream assets which were under construction. In 2011, an immaterial amount of interest was capitalized on oilfield services assets which were under construction. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings.

Accounts Payable and Other Current Liabilities

Included in accounts payable at December 31, 2011 and 2010 are liabilities of approximately $604 million and $251 million, respectively, representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Other current liabilities as of December 31, 2011 and 2010 are detailed below.

	December 31,	
	2011	2010
	($ in millions)	
Revenues and royalties due others	$ 1,090	$ 732
Accrued natural gas and oil drilling and production costs	590	398
Accrued acquisition costs	81	371
Joint interest prepayments received	865	221
Accrued payroll and benefits	199	123
Accrued dividends	99	90
Other	473	280
Total other current liabilities	$ 3,397	$ 2,215

Other Long-Term Liabilities

Other long-term liabilities as of December 31, 2011 and 2010 are detailed below.

	December 31,	
	2011	2010
	($ in millions)	
CHK Utica ORRI conveyance obligation[(a)]	$ 290	$ —
Financing lease obligations[(b)]	143	145
Revenues and royalties due others	109	78
Mortgages payable[(c)]	55	55
Other	221	129
Total other long-term liabilities	$ 818	$ 407

(a) $10 million of the total $300 million obligation is recorded in other current liabilities. See Note 8 for further discussion of the CHK Utica financial transaction.

(b) In 2009, we financed 113 real estate surface assets in the Barnett Shale area for approximately $145 million and entered into a 40-year master lease agreement under which we agreed to lease the sites for approximately $15 million to $27 million annually. This lease transaction was recorded as a financing lease and the cash received was recorded with an offsetting long-term liability on the

consolidated balance sheet. Chesapeake exercised its option to repurchase two of the assets in 2010 and one of the assets in 2011. As of December 31, 2011, we had 110 assets remaining.

(c) In 2009, we financed our regional Barnett Shale headquarters building in Fort Worth, Texas for net proceeds of approximately $54 million with a five-year term loan which has a floating rate of prime plus 275 basis points. At our option, we may prepay in full without penalty beginning in year four. The payment obligation is guaranteed by Chesapeake.

Debt Issuance and Hedging Facility Costs

Included in other long-term assets are costs associated with the issuance of our senior notes and costs primarily associated with our revolving bank credit facilities and hedging facility. The remaining unamortized issuance costs at December 31, 2011 and 2010 totaled $163 million and $162 million, respectively, and are being amortized over the life of the senior notes, revolving bank credit facilities or hedging facility.

Asset Retirement Obligations

We recognize liabilities for retirement obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which a natural gas or oil well is acquired or drilled. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our natural gas and oil properties. See Note 16 for further discussion of asset retirement obligations.

Revenue Recognition

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

Natural Gas Imbalances. We follow the "sales method" of accounting for our natural gas revenue whereby we recognize sales revenue on all natural gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining natural gas reserves on the underlying properties. The natural gas imbalance net position at December 31, 2011 and 2010 was a liability of $8 million and $7 million, respectively.

Marketing, Gathering and Compression Sales. Chesapeake takes title to the natural gas it purchases from other working interest owners in operated wells at the terminus of gathering systems (where applicable), and delivers the natural gas to third parties, at which time revenues are recorded. Chesapeake's results of operations related to its natural gas and oil marketing activities are presented on a "gross" basis, because we act as a principal rather than an agent. Gathering and compression revenues consist of fees billed to other working interest owners in operated wells or third-party producers for the gathering, treating and compression of natural gas. Revenues are recognized when the service is performed and are based upon non-regulated rates and the related gathering, treating and compression volumes. All significant intercompany accounts and transactions have been eliminated.

Oilfield Services Revenue. Our oilfield services operating segment is responsible for contract drilling, oilfield trucking, oilfield rental, pressure pumping and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties. Revenues are recognized when the service is performed. All significant intercompany accounts and transactions have been eliminated.

Derivatives

Chesapeake uses commodity price and financial risk management instruments to mitigate a portion of our exposure to price fluctuations in natural gas and oil prices and changes in interest rates and foreign exchange rates. Results of commodity derivative transactions are reflected in natural gas and oil sales, and results of interest rate and foreign exchange rate derivative transactions are reflected in interest expense.

We have established the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are 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.

Accounting guidance for derivative instruments and hedging activities establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as 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 interest rate derivative instruments designated as fair value hedges, changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are recognized currently in earnings. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative is deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows.

Stock-Based Compensation

Chesapeake's stock-based compensation programs consist of restricted stock, and prior to 2006 stock options, issued to employees and non-employee directors. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the fair value of the equity instruments at the date of the grant. We utilized the Black-Scholes option pricing model to measure the fair value of stock options. To the extent compensation cost relates to employees directly involved in natural gas and oil acquisition, exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expenses, natural gas and oil production expenses, marketing, gathering and compression expenses or oilfield services expense.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

For the years ended December 31, 2011, 2010 and 2009, we recorded the following stock-based compensation:

	Years Ended December 31,		
	2011	2010	2009
		($ in millions)	
Natural gas and oil properties	$ 112	$ 120	$ 112
General and administrative expenses	92	84	74
Natural gas and oil production expenses	33	35	34
Marketing, gathering and compression expenses	17	18	16
Oilfield services expense	11	9	8
Restructuring costs	—	—	9
Total	$ 265	$ 266	$ 253

Cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock are classified as financing cash inflows, while reductions in benefits are classified as operating cash outflows in our consolidated statements of cash flows. For the years ended December 31, 2011, 2010 and 2009, we recognized reductions in tax benefits related to stock-based compensation of $26 million, $13 million and $48 million, respectively.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2010 and 2009 to conform to the presentation used for the 2011 consolidated financial statements.

2. Net Income Per Share

Accounting guidance for earnings per share (EPS) requires presentation of "basic" and "diluted" earnings per share on the face of the statements of operations for all entities with complex capital structures as well as a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

For the years ended December 31, 2011 and 2010, all outstanding securities that were convertible into common stock were included in the calculation of diluted EPS. For the year ended December 31, 2009, the following securities and associated adjustments to net income, consisting of dividends, were not included in the calculation of diluted EPS, as the effects were antidilutive:

	Net Income Adjustments	Shares
	($ in millions)	(in millions)
Year Ended December 31, 2009:		
Common stock equivalent of our preferred stock outstanding:		
4.50% cumulative convertible preferred stock	$ 12	6
5.00% cumulative convertible preferred stock (series 2005B)	$ 10	5
Common stock equivalent of our preferred stock outstanding prior to conversion:		
6.25% mandatory convertible preferred stock	$ 1	1
Unvested restricted stock	$ —	6
Outstanding stock options	$ —	1

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

A reconciliation for the years ended December 31, 2011 and 2010 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
For the Year Ended December 31, 2011:			
Basic EPS	$ 1,570	637	$ 2.47
Effect of Dilutive Securities:			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.75% cumulative convertible preferred stock	86	55	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	63	39	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	11	5	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	12	6	
Unvested restricted stock	—	9	
Outstanding stock options	—	1	
Diluted EPS	$ 1,742	752	$ 2.32
For the Year Ended December 31, 2010:			
Basic EPS	$ 1,663	631	$ 2.63
Effect of Dilutive Securities:			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.75% cumulative convertible preferred stock	49	32	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	39	25	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	11	5	
Common shares assumed issued for 4.50% cumulative convertible preferred stock convertible preferred stock	12	6	
Unvested restricted stock	—	6	
Outstanding stock options	—	1	
Diluted EPS	$ 1,774	706	$ 2.51

As a result of the net loss to common stockholders for the year ended December 31, 2009, both basic weighted average shares outstanding, which are used in computing basic EPS, and diluted weighted average shares outstanding, which are used in computing diluted EPS, were 612 million shares. The basic and diluted loss per common share was $9.57.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

3. Debt

Our long-term debt consisted of the following as of December 31, 2011 and 2010:

	December 31,	
	2011	2010
	($ in millions)	
7.625% senior notes due 2013	$ 464	$ 500
9.5% senior notes due 2015	1,265	1,425
6.25% euro-denominated senior notes due 2017[(a)]	446	796
6.5% senior notes due 2017	660	1,100
6.875% senior notes due 2018	474	600
7.25% senior notes due 2018	669	800
6.625% senior notes due 2019[(b)]	650	—
6.625% senior notes due 2020	1,300	1,400
6.875% senior notes due 2020	500	500
6.125% senior notes due 2021	1,000	—
2.75% contingent convertible senior notes due 2035[(c)]	396	451
2.5% contingent convertible senior notes due 2037[(c)]	1,168	1,378
2.25% contingent convertible senior notes due 2038[(c)]	347	752
Corporate revolving bank credit facility	1,719	3,612
Midstream revolving bank credit facility	1	94
Oilfield services revolving bank credit facility	29	—
Discount on senior notes[(d)]	(490)	(777)
Interest rate derivatives[(e)]	28	9
Total notes payable and long-term debt	$ 10,626	$ 12,640

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.2973 to €1.00 and $1.3269 to €1.00 as of December 31, 2011 and 2010, respectively. See Note 9 for information on our related foreign currency derivatives.

(b) Issuers are Chesapeake Oilfield Operating, L.L.C. (COO) and Chesapeake Oilfield Finance, Inc., a wholly owned subsidiary of COO, formed solely to facilitate the offering of the 6.625% Senior Notes due 2019. It is nominally capitalized and has no operations or revenues. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the fourth quarter of 2011, 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 2012 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	$ 48.51	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.16	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.27	June 14, 2019

(d) Discount at December 31, 2011 and 2010 included $444 million and $711 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

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

Chesapeake Senior Notes and Contingent Convertible Senior Notes

The Chesapeake senior notes and the contingent convertible senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Chesapeake's obligations under the senior notes and the contingent convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our wholly owned subsidiaries. Chesapeake Midstream Development, L.P. and its subsidiaries, Chesapeake Oilfield Services, L.L.C. and its subsidiaries, CHK Utica, L.L.C., Chesapeake Granite Wash Trust and certain de minimis subsidiaries are not guarantors. See Note 18 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. The indentures governing the contingent convertible senior notes do not have any financial or restricted payment covenants.

We are required to account for the liability and equity components of our convertible debt instruments separately and to reflect interest expense at the interest rate of similar nonconvertible debt at the time of issuance. These rates for our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038 are 6.86%, 8.0% and 8.0%, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

In May 2011, we completed and settled tender offers to purchase the following senior notes and contingent convertible senior notes in order to reduce the amount of our outstanding indebtedness. We funded the purchase of the notes with a portion of the net proceeds we received from the sale of our Fayetteville Shale assets which is described in Note 11.

	Principal Amount Purchased
	($ in millions)
7.625% senior notes due 2013	$ 36
9.5% senior notes due 2015	160
6.25% euro-denominated senior notes due 2017[(a)]	380
6.5% senior notes due 2017	440
6.875% senior notes due 2018	126
7.25% senior notes due 2018	131
6.625% senior notes due 2020	100
Total senior notes	1,373
2.75% contingent convertible senior notes due 2035	55
2.5% contingent convertible senior notes due 2037	210
2.25% contingent convertible senior notes due 2038	266
Total contingent convertible senior notes	531
Total	$ 1,904

(a) We purchased €256 million in aggregate principal amount of our euro-denominated senior notes which had a value of $380 million based on the exchange rate of $1.4821 to €1.00. Simultaneously with our purchase of the euro-denominated senior notes, we unwound cross currency swaps for the same principal amount. See Note 9 for additional information.

We paid $2.058 billion in cash for the tender offers described above and recorded associated losses of approximately $174 million. The losses included $154 million in cash premiums, $20 million of deferred charges, $160 million of note discounts and $2 million of interest rate hedging losses, offset by $162 million of the equity component of the contingent convertible notes.

In March 2011, we repurchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $128 million. Associated with these repurchases, we recognized a loss of $2 million.

In February 2011, we issued $1.0 billion principal amount of 6.125% Senior Notes due 2021 in a registered public offering. We used the net proceeds of $977 million from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility.

In August 2010, we filed a shelf registration statement on Form S-3 with the SEC for the offering, from time to time, of debt securities.

In August 2010, we completed a public offering of $2.0 billion aggregate principal amount of senior notes for net proceeds of approximately $1.967 billion. The offering consisted of $600 million of 6.875% Senior Notes due 2018 and $1.4 billion of 6.625% Senior Notes due 2020. We used the net proceeds from the offerings to complete tender offers to purchase senior notes as described below.

In August 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. In September 2010, we redeemed in whole 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 tender offers and redemptions, we recognized a loss of $40 million.

In July 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. Associated with the redemption, we recognized a loss of $19 million.

In June 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 January 2010, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $11 million in aggregate principal amount for an aggregate of 298,500 shares of our common stock in privately negotiated exchanges. Associated with these exchanges, we recognized a loss of $2 million.

No scheduled principal payments are required under the Chesapeake senior notes or contingent convertible senior notes until 2013 when $464 million is due.

COO Senior Notes

In October 2011, our wholly owned subsidiary, COO, issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. COO used the net proceeds of approximately $637 million from the placement to make a cash distribution to its direct parent, Chesapeake Oilfield Services, L.L.C., to enable it to reduce indebtedness under an intercompany note with Chesapeake. Chesapeake then used the cash distribution to reduce indebtedness under its corporate revolving bank credit facility.

The COO senior notes are the unsecured senior obligations of COO and rank equally in right of payment with all of COO's other existing and future senior unsecured indebtedness and rank senior in right of payment to all of its future subordinated indebtedness. The COO senior notes are jointly and severally, fully and unconditionally guaranteed by all of COO's wholly owned subsidiaries, other than de minimis subsidiaries. The notes may be redeemed at any time at specified make-whole or redemption prices and, prior to November 15, 2014, up to 35% of the aggregate principal amount may be redeemed in connection with certain equity offerings. Holders of the COO notes have the right to require COO to repurchase their notes upon a change of control on the terms set forth in the indenture, and COO must offer to repurchase the notes upon certain asset sales. The COO senior notes are subject to covenants that may, among other things, limit the ability of COO and its subsidiaries to make restricted payments, incur indebtedness, issue preferred stock, create liens, and consolidate, merge or transfer assets.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Bank Credit Facilities

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

	Corporate Credit Facility[a]	Midstream Credit Facility[b]	Oilfield Services Credit Facility[c]
		($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	June 2016	November 2016
Borrowing capacity	$ 4,000	$ 600[d]	$ 500[e]
Amount outstanding as of December 31, 2011	$ 1,719	$ 1	$ 29
Letters of credit outstanding as of December 31, 2011	$ 38	$ —	$ —

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

(b) Borrower is Chesapeake Midstream Operating, L.L.C.

(c) Borrower is Chesapeake Oilfield Operating, L.L.C.

(d) We estimate the capacity was limited to approximately $280 million as of December 31, 2011 by certain restrictive provisions.

(e) We estimate the capacity was limited to approximately $290 million as of December 31, 2011 by certain restrictive provisions.

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, our credit facilities do not contain provisions which would trigger an acceleration of amounts due under the respective 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 determined 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, 2011. 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 $600 million midstream syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems in support of 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, other than certain joint venture equity interests, of the wholly owned subsidiaries (the restricted subsidiaries) of Chesapeake Midstream Development, L.P. (CMD), itself a wholly owned subsidiary of Chesapeake. Amounts outstanding 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 1.00% to 1.75% or (ii) the Eurodollar rate, which is based on LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. 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 midstream master limited partnership affiliate, CHKM. In December 2011, the leverage ratio increased for a three-fiscal-quarter period beginning October 1, 2011 due to the sale of CMD's wholly owned subsidiary, Appalachia Midstream Services, L.L.C., as it was classified as a material disposition of assets. We were in compliance with all covenants under the agreement at December 31, 2011. 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 CMD and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

Oilfield Services Credit Facility

In November 2011, we closed on a new syndicated revolving bank credit facility for our oilfield services operations, which have recently been segregated under the wholly owned subsidiary Chesapeake Oilfield Services, L.L.C. and its wholly owned subsidiary COO. The facility matures in November 2016, has initial commitments of $500 million and may be expanded to $900 million at COO's option, subject to additional bank participation. The facility is used to fund capital expenditures

and for general corporate purposes associated with our oilfield services operations. Borrowings under the credit facility are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries), and bear interest at our option at either (i) the greater of the reference rate of Bank of America, N.A., the federal funds effective rate plus 0.50%, and one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 1.00% to 1.75% per annum or (ii) the Eurodollar rate, which is based on LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the credit facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The oilfield services credit facility agreement contains various covenants and restrictive provisions which limit the ability of COO 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 lease adjusted indebtedness to EBITDAR, a senior secured leverage ratio based on the ratio of secured indebtedness to EBITDA and a fixed charge coverage ratio based on the ratio of lease adjusted interest expense to EBITDAR, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at December 31, 2011. If COO 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 oilfield services credit facility agreement also has cross default provisions that apply to other indebtedness COO and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

4. Contingencies and Commitments

Contingencies

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. On September 2, 2010, the court denied the defendants' motion to dismiss, and on August 1, 2011, the plaintiffs filed a motion for class certification. Discovery in the case is proceeding. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against certain current and former directors and officers of the Company asserting breaches of fiduciary duties relating to alleged material omissions in the registration statement for the July 2008 offering. The derivative action is stayed pursuant to stipulation. A second derivative action relating to the July 2008 offering was filed against certain current and former directors and officers of the Company in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. This action also asserts breaches of fiduciary duties with respect to alleged material omissions in the offering registration statement. The Company filed a motion to dismiss the action on November 30, 2011, and plaintiffs filed an Opposition on January 9, 2012. Chesapeake is named as a nominal defendant in both derivative actions.

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, among other things, breaches of fiduciary duties relating to the 2008 compensation of the Company's CEO, Aubrey K. McClendon, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition naming Chesapeake as a nominal defendant was filed on June 23, 2009. Chesapeake's motion to dismiss was granted on February 26, 2010, and the Oklahoma Court of Civil Appeals affirmed the dismissal on August 26, 2011. The plaintiffs filed a petition for writ of certiorari with the Oklahoma Supreme Court on September 13, 2011.

On January 30, 2012, the District Court of Oklahoma County, Oklahoma approved the settlement between the parties in the consolidated derivative action, as well as a case on appeal at the Oklahoma Court of Civil Appeals requesting inspection of Company books and records relating to the December 2008 employment agreement with its CEO. The principal terms of the settlement include the rescission of the sale of an antique map collection that occurred in December 2008 between Mr. McClendon and the Company, whereby Mr. McClendon will pay the Company $12 million plus interest and the Company will reconvey the map collection to Mr. McClendon, and the adoption and/or implementation of a variety of corporate governance measures. The court awarded attorney fees and expenses to plaintiffs' counsel in the amount of $3,750,000, to be paid by Chesapeake and/or its insurers. Pursuant to the settlement, the consolidated derivative action and books and records action were dismissed with prejudice against all defendants.

On September 6 and 8, 2011, in separate derivative actions filed in the U.S. District Court for the Western District of Oklahoma against certain of the Company's current and former directors, two shareholders alleged that the Chesapeake board wrongfully refused their demands to investigate purported breaches of fiduciary duties relating to Mr. McClendon's 2008 compensation and, as a result, each of these shareholders asserts he is entitled to seek relief on behalf of the Company. These federal derivative actions were consolidated on December 23, 2011 and were stayed pending final approval of the state court settlement. On February 7, 2012, the Court entered an order deferring defendants' response to the complaint until March 6, 2012.

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, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their natural gas and oil 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 has successfully defended a number of these cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal. Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute incidental to the Company's business operations is likely to have a material adverse effect on its 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.

The Company records an associated liability when a loss is probable and the amount is reasonably estimable. The Company accounts for legal defense costs in the period the costs are incurred.

Environmental Risk

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

There are presently pending against us orders for compliance issued by the U.S. Environmental Protection Agency (EPA) related to our compliance with Clean Water Act (CWA) permitting requirements in West Virginia, and for four of the sites subject to EPA orders for compliance, we have also received and have responded to a federal grand jury subpoena requesting documents. We understand that the U.S. Department of Justice is investigating possible criminal violations of and liabilities under the CWA with respect to three of the four sites. The CWA provides authority for significant civil and criminal penalties for the placement of fill in a jurisdictional stream or wetland without a permit from the Army Corps of Engineers. CWA civil penalties can be as high as $37,500 per day, per violation, and possible criminal penalties range from $2,500 to $25,000 per day, per violation, for misdemeanor liability (i.e., criminally negligent conduct) and from $5,000 to $50,000 per day, per violation, for felony liability (i.e., knowing conduct). In addition, the West Virginia Department of Environmental Protection has issued orders for compliance related to alleged violations of the West Virginia Dam Control and Safety Act at four structures constructed for Chesapeake in West Virginia. Although we cannot estimate the amount of any monetary sanctions, resolution of the orders for compliance related to alleged violations of the West Virginia Dam Control and Safety Act, EPA's compliance orders under the CWA, and the DOJ's investigation under the CWA can each reasonably be expected to include monetary sanctions in excess of $100,000.

Commitments

Rig Leases

In a series of transactions since 2006, our drilling subsidiaries have sold 93 drilling rigs (net of one repurchased rig) and related equipment for $802 million and entered into master lease agreements under which we agreed to lease the rigs from the buyer for initial terms of five to ten years. The lease obligations are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is amortized to oilfield services expense over the lease term. Under the leases, we can exercise an early purchase option or we can purchase the rigs at the expiration of the lease for the fair market value at the time. In addition, in most cases we have the option to renew the lease for negotiated new terms at the expiration of the lease.

Compressor Leases

Through various transactions since 2007, our compression subsidiary has sold 2,542 compressors (net of six repurchased units), a significant portion of its compressor fleet, for $635 million

and entered into a master lease agreement. The term of the agreement varies by buyer ranging from four to ten years. The lease obligations are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is amortized to marketing, gathering and compression expenses over the lease term. Under the leases, we can exercise an early purchase option or we can purchase the compressors at the expiration of the lease for the fair market value at the time. In addition, in most cases we have the option to renew the lease for negotiated new terms at the expiration of the lease.

Future operating lease obligations related to rigs, compressors and other equipment or property are not recorded in the accompanying consolidated balance sheets. The aggregate undiscounted minimum future lease payments are presented below.

	December 31, 2011			
	Rigs	Compressors	Other	Total
	($ in millions)			
2012	$ 110	$ 73	$ 17	$ 200
2013	112	77	15	204
2014	98	131	11	240
2015	39	56	9	104
2016	67	95	7	169
After 2016	26	50	5	81
Total	$ 452	$ 482	$ 64	$ 998

Rent expense, including short-term rentals, for the years ended December 31, 2011, 2010 and 2009 was $184 million, $161 million and $149 million, respectively.

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers, including our equity affiliate CHKM, for future gathering, processing and transportation of natural gas and liquids to move certain of our production to market. Working interest owners will be responsible for their proportionate share of these costs under joint operating agreements. Commitments related to gathering, processing and transportation agreements are not recorded in the accompanying consolidated balance sheets.

The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest owners, are presented below.

	December 31, 2011
	($ in millions)
2012	$ 1,030
2013	1,175
2014	1,218
2015	1,306
2016	1,380
After 2016	7,664
Total	$ 13,773

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Drilling Contracts

Chesapeake has contracts with various drilling contractors to lease approximately 58 rigs with terms ranging from three months to three years. These commitments are not recorded in the accompanying consolidated balance sheets. As of December 31, 2011, the aggregate undiscounted minimum future drilling rig commitments are presented below.

	December 31, 2011
	($ in millions)
2012	$ 194
2013	78
2014	135
Total	$ 407

Drilling Obligations

In December 2011, as part of our Utica joint venture development agreement with Total, we committed to spud not less than 90 cumulative Utica wells by December 31, 2012, 270 cumulative wells by December 31, 2013 and 540 cumulative wells by December 31, 2014. If we fail to meet the drilling commitment at any such year end for any reason other than a force majeure event, the drilling carry percentage used to determine our promoted well reimbursement will be reduced from 60% to 45% for a number of wells drilled in the following calendar year equal to the number of wells we were short the drilling commitment. This reduction will not affect the total carry to be received.

We have also committed to drill wells in conjunction with our CHK Utica financial transaction and in conjunction with the formation of the Chesapeake Granite Wash Trust. See Note 8 for discussion of noncontrolling interests.

Natural Gas and Oil Purchase Obligations

Our marketing segment regularly commits to purchase natural gas from other owners in our properties and such commitments typically are short-term in nature. We have also committed to purchase any natural gas and oil associated with certain volumetric production payment transactions. The purchase commitments are based on market prices at the time of production, and the purchased natural gas and oil is resold.

Net Acreage Maintenance Commitments

Under the terms of our joint venture agreements with Statoil, Total and CNOOC (see Note 11), we are required to extend, renew or replace certain expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated joint development areas.

Other Commitments

In April 2011, we entered into a master frac service agreement with our equity affiliate, FTS International, LLC (FTS), which expires on December 31, 2014. Pursuant to this agreement, we are committed to enter into a predetermined number of backstop contracts if utilization of FTS fleets falls below a certain level. We have guaranteed a gross profit margin of 10% to FTS on such backstop contracts. To date, we have not entered into any backstop contracts, and since we use fracing services continuously, we do not anticipate any material payments under this commitment.

In July 2011, we agreed to invest $150 million in newly issued convertible promissory notes of Clean Energy Fuels Corp. (Nasdaq:CLNE), based in Seal Beach, California. The investment is being made in three equal $50 million promissory notes, the first of which was issued on July 11, 2011, with the remaining notes scheduled to be issued in June 2012 and June 2013. The notes bear interest at the annual rate of 7.5%, payable quarterly, and are convertible at our option into shares of Clean Energy's common stock at a 22.5% conversion premium, resulting in a conversion price of $15.80 per share. See Note 12 for further discussion of this investment.

In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Louisville, Colorado. The first $35 million tranche of our investment was funded in July 2011 and the remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached by July 2013. See Note 12 for further discussion of this investment.

In December 2011, we sold Appalachia Midstream Services, L.L.C., a wholly owned subsidiary of CMD, to our equity affiliate, CHKM, for total consideration of $879 million, subject to a customary post-closing working capital adjustment. In addition, CMD has committed to pay CHKM for any quarterly shortfall between the actual adjusted EBITDA from the assets sold and specified quarterly targets, which total $100 million in 2012 and $150 million in 2013. We recorded this guarantee at an estimated fair value of $27 million at the time of the sale. It is included in other current and non-current liabilities on our consolidated balance sheet as of December 31, 2011. We will release this liability over the two-year term of the guarantee if the assets are meeting the specific quarterly targets. To the extent we are required to make payments under the guarantee, we will record the differences between the liability and the associated payments in earnings. See Note 11 for further discussion of this transaction.

In conjunction with an acceleration of the remaining drilling carry owed us by Total in our Barnett Shale joint venture, we agreed to maintain our operated rig count at no less than six rigs in the Barnett Shale through December 31, 2012.

As part of our normal course of business, we enter into various agreements providing, or otherwise arranging, financial or performance assurances to third parties on behalf of our consolidated subsidiaries. These agreements may include future payment obligations or commitments regarding operational performance that effectively guarantees our subsidiaries' future performance.

In connection with our purchase and sale agreements, we have frequently provided for indemnification to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party or in regards to perfecting title to property. These indemnifications generally have a discrete term and are intended to protect the parties against the risks that are difficult to predict or cannot be quantified at the time of the consummation of a particular transaction.

Certain of our natural gas and oil properties are burdened by non-operating interests such as royalties, overriding royalties and volumetric production payments. As the holder of the working interest from which such interests have been carved, we have the responsibility to bear the cost of developing and producing the reserves attributable to such interests.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

5. Income Taxes

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

	Years Ended December 31,		
	2011	2010	2009
		($ in millions)	
Current	$ 13	$ —	$ 4
Deferred	1,110	1,110	(3,487)
Total	$ 1,123	$ 1,110	$ (3,483)

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

	Years Ended December 31,		
	2011	2010	2009
		($ in millions)	
Income tax expense (benefit) at the federal statutory rate (35%)	$ 1,008	$ 1,009	$ (3,251)
State income taxes (net of federal income tax benefit)	74	78	(275)
Other	41	23	43
Total	$ 1,123	$ 1,110	$ (3,483)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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

	Years Ended December 31,	
	2011	2010
	($ in millions)	
Deferred tax liabilities:		
Natural gas and oil properties	$ (2,883)	$ (2,074)
Other property and equipment	(634)	(184)
Investments	(56)	—
Volumetric production payments	(1,453)	(1,394)
Contingent convertible debt	(396)	(493)
Deferred tax liabilities	(5,422)	(4,145)
Deferred tax assets:		
Net operating loss carryforwards	1,198	1,386
Derivative instruments	395	115
Asset retirement obligations	123	114
Investments	—	40
Deferred stock compensation	62	84
Accrued liabilities	82	25
Alternative minimum tax credits	257	11
State statutory depletion	121	93
Other	85	32
Deferred tax assets	2,323	1,900
Net deferred tax asset (liability)	(3,099)	(2,245)
Other non-current tax liabilities	(246)	—
Total deferred tax liabilities	$ (3,345)[(a)]	$ (2,245)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 139	$ 139
Non-current deferred income tax liability	(3,484)	(2,384)
Total	$ (3,345)	$ (2,245)

(a) In addition to the income tax expense of $1.123 billion, activity during 2011 includes an increase to deferred tax liabilities of $26 million related to stock-based compensation, $25 million related to acquisitions and $1 million related to derivative instruments. The activity during 2011 also includes a decrease to deferred tax liabilities of $74 million related to the repurchase of contingent convertible notes and $1 million related to investments. These items were not recorded as part of the provision for income taxes.

As of December 31, 2011 and 2010, we classified $139 million of deferred tax assets as current that were attributable to current temporary differences associated with accrued liabilities, derivative liabilities and other items. As of December 31, 2011 and 2010, non-current deferred tax liabilities on the consolidated balance sheet included net non-current deferred tax liabilities of $3.238 billion and $2.384 billion, respectively. Also, included as of December 31, 2011 was $246 million of non-current liabilities related to uncertain tax positions associated with the federal alternative minimum tax.

Deferred tax assets relating to tax benefits of employee share-based compensation have been reduced related to stock options exercised and restricted stock that vested in periods in which Chesapeake was in a net operating loss position. Some exercises and vestings result in tax deductions

in excess of previously recorded benefits based on the stock option or restricted stock value at the time of grant (windfalls). Although these additional tax benefits or windfalls are reflected in net operating loss carryforwards in the tax return, the additional tax benefit associated with the windfalls is not recognized until the deduction reduces taxes payable pursuant to accounting for stock compensation under GAAP. Accordingly, since the tax benefit does not reduce Chesapeake's current taxes payable due to net operating loss carryforwards, these windfall tax benefits are not reflected in Chesapeake's net operating losses in deferred tax assets as of December 31, 2011. Windfalls included in net operating loss carryforwards but not reflected in deferred tax assets as of December 31, 2011 totaled $21.2 million. Any shortfalls resulting from tax deductions that were less than the previously-recorded benefits were recorded as reductions to additional paid-in capital.

At December 31, 2011, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $3.155 billion which excludes the NOL carryforwards related to unrecognized tax benefits and stock compensation windfalls that have not been recognized under GAAP. Additionally, we had $66 million of alternative minimum tax (AMT) NOL carryforwards, net of unrecognized tax benefits, available as a deduction against future AMT income. The NOL carryforwards expire from 2019 through 2031. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income.

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

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

The following table summarizes our net operating losses as of December 31, 2011 and any related limitations:

	Total	Limited	Annual Limitation
		($ in millions)	
Net operating loss	$ 3,155	$ 80	$ 16
AMT net operating loss	$ 66	$ 66	$ 15

As of December 31, 2011, we do not believe that an ownership change has occurred. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

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. As of December 31, 2011, the amount of unrecognized tax benefits related to NOL carryforwards associated with uncertain tax positions and AMT associated with uncertain tax positions was $369 million. As of December 31, 2010, the amount of unrecognized tax benefits related to AMT associated with uncertain tax positions was $34 million. If these unrecognized tax benefits are disallowed and we are required to pay additional AMT liabilities, any payments can be utilized as credits against future regular tax liabilities. If these unrecognized tax benefits are disallowed and our NOL carryforwards are reduced, the reduction will be offset by additional tax basis that will generate future deductions. The uncertain tax positions identified would not have a material effect on the effective tax rate. As of December 31, 2011, we had an accrued liability of $12 million for interest related to these uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

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

	2011	2010	2009
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 34	$ 231	$ 60
Additions based on tax positions related to the current year	135	—	171
Additions to tax positions of prior years	200	(197)	—
Settlements	—	—	—
Unrecognized tax benefits at end of period	$ 369	$ 34	$ 231

Chesapeake files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. With few exceptions, Chesapeake is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years prior to 2007. The Internal Revenue Service (IRS) is currently examining Chesapeake's 2007, 2008 and 2009 U.S. income tax returns.

6. Related Party Transactions

Chief Executive Officer

As of December 31, 2011 and 2010, we had accrued accounts receivable from our Chief Executive Officer, Aubrey K. McClendon, of $45 million and $30 million, respectively, representing joint interest billings from December 2011 and 2010. These amounts were invoiced and timely paid in the following month. 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. From time to time, Mr. McClendon has sold his FWPP interests in conjunction with sales by the Company of its interests in the same properties, and the proceeds related to those sales have been allocated between Mr. McClendon and the Company based on their respective ownership interests and on the same terms as those that applied to the Company's properties included in the sale.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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. 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. We are recognizing the incentive award as general and administrative expense over the five-year vesting period for the clawback resulting in an expense of approximately $15 million per year beginning in 2009. The net incentive award, after deduction of applicable withholding and employment taxes, 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.

In 2011, Chesapeake entered into a license and naming rights agreement with The Professional Basketball Club, LLC (PBC) for the arena in downtown Oklahoma City. The PBC is the owner of the Oklahoma City Thunder basketball team, a National Basketball Association franchise and the arena's primary tenant. Mr. McClendon has a 19.2% equity interest in PBC. Under the terms of the agreement, Chesapeake has committed to pay fees ranging from $3 million to $4 million per year through 2023 for the arena naming rights and other associated benefits. The naming rights provide Chesapeake with an enhanced public awareness and recognition both locally and nationally. Since 2008, Chesapeake has been a founding sponsor of the Oklahoma City Thunder under successive one-year contracts. In 2011, it entered into a 12-year sponsorship agreement, committing to pay an average annual fee of $3 million for advertising, use of an arena suite and other benefits. In 2011, the Company also agreed to purchase Oklahoma City Thunder game tickets for the 2011-2012 regular season home games for approximately $3 million and committed to purchase tickets for any 2012 home playoff games.

Pursuant to a court-approved litigation settlement with certain plaintiff shareholders described in Note 4, the sale of an antique map collection that occurred in December 2008 between Mr. McClendon and the Company will be rescinded. Mr. McClendon will pay the Company approximately $12 million plus interest, and the Company will reconvey the map collection to Mr. McClendon. The transaction is scheduled to be completed not later than 30 days after entry of a final non-appealable judgment.

Other Related Parties

During 2011 and 2010, our 46%-owned affiliate, CHKM, provided us natural gas gathering and treating services in the ordinary course of business. In addition, there are agreements in place whereby we support CHKM in functions for which we are reimbursed. During 2011 and 2010, our transactions with CHKM included the following:

	Years Ended December 31,	
	2011	2010
	($ in millions)	
Amounts paid to CHKM:		
Gas gathering fees (a)	$ 469	$ 378
Amounts received from CHKM:		
Compressor rentals	60	48
Inventory purchases	93	47
Other services provided	91	73
Total amounts received from CHKM	$ 244	$ 168

(a) Other working interest and royalty owners are charged their proportionate share of the gas gathering fees.

As of December 31, 2011 and 2010, we had net receivables (payables) from (to) CHKM of $2 million and ($45) million, respectively. In addition, in 2011 and 2010, we sold natural gas gathering systems and related equipment to CHKM. See Note 11 for further discussion.

During 2011, 2010 and 2009, our 30%-owned affiliate, FTS, provided us pressure pumping and other services in the ordinary course of business. During 2011, 2010 and 2009, we paid FTS $369 million, $89 million and $43 million, respectively, for these services. As well operators, we are reimbursed by other working interest owners through the joint interest billing process for their proportionate share of these costs. As of December 31, 2011, 2010 and 2009, we had $115 million, $30 million and $8 million, respectively, due FTS for services provided and not yet paid.

7. Employee Benefit Plans

Our qualified 401(k) profit sharing plan (401(k) Plan) is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except certain employees of Chesapeake Appalachia, L.L.C. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) Plan accounts, subject to plan limits and those set by the Internal Revenue Service. Chesapeake matches employee contributions dollar for dollar (subject to a maximum contribution of 15% of an employee's annual salary and bonus compensation) with Chesapeake common stock purchased in the open market. The Company contributed $72 million, $54 million and $48 million to the 401(k) Plan in 2011, 2010 and 2009, respectively.

Chesapeake also maintains a nonqualified deferred compensation plan, the Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan (DC Plan). Prior to 2009, to be eligible to participate in the DC Plan, an employee must have received annual compensation (base salary and bonus combined in the prior 12 months) of at least $100,000, had a minimum of one year of service as a Company employee and have made the maximum contribution allowable under the 401(k) Plan. For employees with at least five years of service as a Company employee, the Company matched employee contributions to the plan in Chesapeake common stock. On January 1, 2009, the plan was amended to allow for participation for any employees who received compensation (base salary only) of at least $150,000 and had an employment agreement with the Company. The plan amendment also allowed an employee who is at least age 55 to elect for the matching contributions to be made in any one of the investment options. In addition, in 2009 and 2010, the Company matched employee contributions with Chesapeake common stock once the employee had at least three years of service as a Company employee. Chesapeake matches 100% of employee contributions up to 15% of base salary and bonus in the aggregate for the DC Plan. In 2011, the Company began matching contributions immediately upon an employee's participation in the DC plan. The maximum compensation that can be deferred by employees under all Company deferred compensation plans, including the Chesapeake 401(k) plan, is a total of 75% of base salary and 100% of performance bonus. We contributed $12 million, $9 million and $7 million to the DC Plan during 2011, 2010 and 2009, respectively, to fund the match. The Company's non-employee directors are able to defer up to 100% of director fees into the DC Plan.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Chesapeake maintains no post-employment benefit plans except those sponsored by its wholly owned subsidiary, Chesapeake Appalachia, L.L.C. Participation in these plans is limited to existing employees who are union members and former employees who were union members. The Chesapeake Appalachia, L.L.C. benefit plans provide health care and life insurance benefits to eligible employees upon retirement. We account for these benefits on an accrual basis. As of December 31, 2011, the Company had accrued approximately $2 million in accumulated post-employment benefit liability.

8. Stockholders' Equity, Restricted Stock, Stock Options and Noncontrolling Interests

Common Stock

The following is a summary of the changes in our common shares issued for 2011, 2010 and 2009:

	Years Ended December 31,		
	2011	2010	2009
		(in thousands)	
Shares issued at January 1	655,251	648,549	607,953
Restricted stock issuances (net of forfeitures)	4,961	5,924	3,633
Stock option exercises	565	458	508
Preferred stock conversions	111	21	1,422
Convertible note exchanges	—	299	10,210
Common stock issued for the purchase of proved and unproved properties	—	—	24,823
Shares issued at December 31	660,888	655,251	648,549

In 2010 and 2009, 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	Number of Common Shares
		($ in millions)	(in thousands)
2010	2.25% due 2038	$ 11	299
2009	2.25% due 2038	$ 364	10,210

The difference between the allocated debt value of the notes that were exchanged and the fair value of the common stock issued resulted in a loss of $2 million and $40 million, including deferred charges associated with the exchanges, on the cancellation of indebtedness for the years ended December 31, 2010 and 2009, respectively.

In 2009, we issued 24,822,832 shares of common stock, valued at $429 million for the purchase of proved and unproved properties pursuant to an acquisition shelf registration statement.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2011:

Preferred Stock Series	Issue Date	Liquidation Preference per Share	Holder's Conversion Right	Conversion Rate	Conversion Price	Company's Conversion Right From	Company's Market Conversion Trigger[(a)]
5.75% cumulative convertible non-voting	May and June 2010	$ 1,000	Any time	37.0370	$ 27.0000	May 17, 2015	$ 35.1000
5.75% (series A) cumulative convertible non-voting	May 2010	$ 1,000	Any time	35.7961	$ 27.9360	May 17, 2015	$ 36.3168
4.50% cumulative convertible	September 2005	$ 100	Any time	2.2772	$ 43.9142	September 15, 2010	$ 57.0885
5.00% cumulative convertible (series 2005B)	November 2005	$ 100	Any time	2.5766	$ 38.8108	November 15, 2010	$ 50.4540

(a) Convertible at the Company's option if the trading price of the Company's common stock equals or exceeds the trigger price for a specified time period or after the conversion date indicated if there are less than 250,000 shares of 4.50% or 5.00% (series 2005B) preferred stock outstanding or 25,000 shares of 5.75% or 5.75% (series A) preferred stock outstanding.

The following reflects the changes in our preferred shares outstanding for 2011, 2010 and 2009:

	5.75%	5.75% (A)	4.50%	5.00% (2005B)	5.00% (2005)	6.25%	4.125%
				(in thousands)			
Shares outstanding at January 1, 2011	1,500	1,100	2,559	2,096	—	—	—
Conversion of preferred for common stock	(3)	—	—	—	—	—	—
Shares outstanding at December 31, 2011	1,497	1,100	2,559	2,096	—	—	—
Shares outstanding at January 1, 2010	—	—	2,559	2,096	5	—	—
Preferred stock issuances	1,500	1,100	—	—	—	—	—
Conversion of preferred for common stock	—	—	—	—	(5)	—	—
Shares outstanding at December 31, 2010	1,500	1,100	2,559	2,096	—	—	—
Shares outstanding at January 1, 2009	—	—	2,559	2,096	5	144	3
Conversion of preferred for common stock	—	—	—	—	—	(144)	(3)
Shares outstanding at December 31, 2009	—	—	2,559	2,096	5	—	—

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

In 2011, 2010 and 2009, shares of our cumulative convertible preferred stock were converted into shares of common stock as summarized below.

Year of Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares
		(in thousands)	
2011	5.75%	3	111
2010	5.0% (series 2005)	5	21
2009	6.25%	144	1,239
	4.125%	3	183
			1,422

There were no gains or losses associated with the conversions noted above.

Dividends

Dividends declared on our common stock and preferred stock are reflected as adjustments to retained earnings to the extent a surplus of retained earnings will exist after giving effect to the dividends. To the extent retained earnings are insufficient to fund the distributions, such payments constitute a return of contributed capital rather than earnings and are accounted for as a reduction to paid-in capital.

Dividends on our outstanding preferred stock are payable quarterly. We may pay dividends on our 5.00% Cumulative Convertible Preferred Stock (Series 2005B) and our 4.50% Cumulative Convertible Preferred Stock in cash, common stock or a combination thereof, at our option. Dividends on both series of our 5.75% Cumulative Convertible Non-Voting Preferred Stock are payable only in cash.

Stock-Based Compensation Plans

Under Chesapeake's Long Term Incentive Plan, restricted stock, stock options, stock appreciation rights, performance shares and other stock awards may be awarded to employees, directors and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares of common stock available for awards under the plan may not exceed 43,000,000 shares. The maximum period for exercise of an option or stock appreciation right may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option or stock appreciation right on the date of grant. Awards granted under the plan become vested at specified dates or upon the satisfaction of certain performance or other criteria determined by a committee of the Board of Directors. No awards may be granted under this plan after September 30, 2014. This plan has been approved by our shareholders. There were 68,824, 87,500 and 87,500 shares of restricted stock issued to our non-employee directors from this plan in 2011, 2010 and 2009, respectively. Additionally, there were 4.5 million, 5.8 million and 4.0 million restricted shares issued, net of forfeitures, to employees and consultants during 2011, 2010 and 2009, respectively, from this plan. As of December 31, 2011, there were 9.2 million shares remaining available for issuance under the plan.

Under Chesapeake's 2003 Stock Incentive Plan, restricted stock and incentive and nonqualified stock options to purchase our common stock may be awarded to employees and consultants of

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares available for awards under the plan may not exceed 10,000,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option on the date of grant. Restricted stock and options granted become vested at dates determined by a committee of the Board of Directors. No awards may be granted under this plan after April 14, 2013. This plan has been approved by our shareholders. There were 0.4 million, 0.1 million and (0.4) million restricted shares, net of forfeitures, issued during 2011, 2010 and 2009, respectively, from this plan. As of December 31, 2011, there were approximately 89,000 shares remaining available for issuance under the plan.

Under Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, 10,000 shares of Chesapeake's common stock are awarded to each newly appointed non-employee director on his or her first day of service. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued may not exceed 100,000 shares. This plan has been approved by our shareholders. In each of 2011, 2010 and 2009, 10,000 shares of common stock were awarded to new directors from this plan. As of December 31, 2011, there were 30,000 shares remaining available for issuance under this plan.

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

Name of Plan	Eligible Participants	Type of Options	Shares Covered	Shareholder Approved	Outstanding Options at December 31, 2011
2002 and 2001 Stock Option Plans	Employees and consultants	Incentive and nonqualified	3,000,000/ 3,200,000	Yes	382,320
2002 and 2001 Nonqualified Stock Option Plans	Employees and consultants	Nonqualified	4,000,000/ 3,000,000	No	470,953
2000 and 1999 Employee Stock Option Plans	Employees and consultants	Nonqualified	3,000,000 (each plan)	No	47,700
1996 and 1994 Stock Option Plans	Employees and consultants	Incentive and nonqualified	6,000,000/ 4,886,910	Yes	32,941

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is generally four years from the date of grant for employees and three years for non-employee directors. To the extent compensation cost relates to employees directly involved in natural gas and oil acquisition, exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expense, production expenses, marketing, gathering and compression expenses or oilfield services expense. Note 1 details the accounting for our stock-based compensation expense in 2011, 2010 and 2009.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

A summary of the status of the unvested shares of restricted stock and changes during 2011, 2010 and 2009 is presented below.

	Number of Unvested Restricted Shares (in thousands)	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2011	21,375	$ 28.68
Granted	9,541	$ 28.38
Vested	(10,401)	$ 31.76
Forfeited	(971)	$ 27.28
Unvested shares as of December 31, 2011	19,544	$ 26.97
Unvested shares as of January 1, 2010	19,225	$ 31.89
Granted	9,061	$ 24.19
Vested	(5,900)	$ 31.99
Forfeited	(1,011)	$ 30.05
Unvested shares as of December 31, 2010	21,375	$ 28.68
Unvested shares as of January 1, 2009	21,622	$ 38.85
Granted	8,019	$ 18.65
Vested	(9,214)	$ 36.38
Forfeited	(1,202)	$ 34.46
Unvested shares as of December 31, 2009	19,225	$ 31.89

The aggregate intrinsic value of restricted stock vested during 2011 was approximately $298 million based on the stock price at the time of vesting.

As of December 31, 2011, there was $345 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of approximately 2.5 years.

The vesting of certain restricted stock grants could result in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the years ended December 31, 2011, 2010 and 2009, we recognized reductions in tax benefits related to restricted stock of $23 million, $15 million and $49 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Stock Options

We granted stock options prior to 2006 under several stock compensation plans. Outstanding options expire ten years from the date of grant and vested over a four-year period. All of our stock options outstanding are fully vested and exercisable and there are no shares authorized for future grants.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table provides information related to stock option activity for 2011, 2010 and 2009:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)]
	(in thousands)			($ in millions)
Outstanding at January 1, 2011	1,808	$ 8.90		
Exercised	(757)	7.59		$ 15
Forfeited/Canceled	—	—		
Outstanding and exercisable at December 31, 2011	1,051	$ 9.84	1.41	$ 13
Outstanding at January 1, 2010	2,283	$ 8.36		
Exercised	(475)	6.29		$ 8
Forfeited/Canceled	—	—		
Outstanding and exercisable at December 31, 2010	1,808	$ 8.90	2.03	$ 31
Outstanding at January 1, 2009	2,802	$ 8.13		
Exercised	(508)	7.12		$ 8
Forfeited/Canceled	(11)	6.47		
Outstanding and exercisable at December 31, 2009	2,283	$ 8.36	2.75	$ 40

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

There is no remaining unrecognized compensation cost related to unvested stock options.

During the year ended December 31, 2011, we recognized a reduction in tax benefits related to stock options of $3 million. During the years ended December 31, 2010 and 2009, we recognized excess tax benefits related to stock options of $2 million and $1 million, respectively. All amounts were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table summarizes information about stock options outstanding and exercisable at December 31, 2011:

Range of Exercise Prices			Number of Options (in thousands)	Weighted-Avg. Remaining Contractual Life in Years	Weighted-Avg. Exercise Price
$ 5.20	–	$ 5.20	167	0.56	$ 5.20
5.35	–	7.74	57	0.48	6.50
7.80	–	7.80	221	1.02	7.80
7.86	–	10.01	56	1.06	8.49
10.08	–	10.08	291	1.48	10.08
10.10	–	13.37	119	1.94	12.26
13.58	–	15.06	27	2.47	14.96
15.47	–	15.47	38	3.01	15.47
16.08	–	16.08	25	2.75	16.08
22.49	–	22.49	50	3.25	22.49
$ 5.20	–	$ 22.49	1,051	1.41	$ 9.84

Noncontrolling Interests

Utica Financial Transaction. CHK Utica, L.L.C. (CHK Utica) is an unrestricted, non-guarantor consolidated subsidiary we formed in October 2011 to develop a portion of our Utica Shale natural gas and oil assets. In exchange for all of the common shares, we contributed to CHK Utica approximately 700,000 net acres of leasehold within an area of mutual interest in the Utica Shale play covering 13 counties located primarily in eastern Ohio. During November and December 2011, in private placements, third-party investors contributed $1.25 billion in cash to CHK Utica in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3% overriding royalty interest (ORRI) in up to 1,500 net wells to be drilled on certain of our Utica Shale leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK Utica limited liability company agreement (the LLC Agreement), as the holder of all the common shares and the sole managing member of CHK Utica, we maintain voting and managerial control of CHK Utica and therefore include it in our consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $300 million to the ORRI obligation and $950 million to the preferred shares. The ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our consolidated balance sheet. Pursuant to the LLC Agreement, CHK Utica is required to retain $400 million of the $1.25 billion of investment proceeds to fund its development activities and make the next two quarters of preferred dividend payments. The amount retained for paying such dividends, approximately $44 million, is reflected as restricted cash on our consolidated balance sheet.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 7% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, cash flow from the assets owned by CHK Utica are insufficient to fund the dividend in full in any quarter, whether as a result of capital expenditures, drilling results or otherwise. We have committed to drill, for the benefit of CHK Utica, a minimum of 50 net wells per year through 2016 in the CHK Utica area of mutual interest, up to a minimum cumulative total of 250 net wells. If we fail to meet the then-current drilling commitment in any year, we must pay to CHK Utica $5

million for each well we are short of such drilling commitment. As the managing member of CHK Utica, we may, at our sole discretion and election at any time after December 31, 2013, distribute certain excess cash of CHK Utica, as determined in accordance with the LLC Agreement. Any such optional distribution of excess cash is allocated 70% to the preferred shares (which is applied toward redemption of the preferred shares) and 30% to the common shares unless we have not met our drilling commitment at such time, in which case such optional distributions would be allocated 100% to the preferred shares (and applied toward redemption thereof). We may also, at our sole election and discretion, in accordance with the LLC Agreement, cause CHK Utica to redeem the CHK Utica preferred shares for cash, in whole or in part. The preferred shares will be redeemed at a valuation equal to the greater of a 10% internal rate of return or a return on investment of 1.4x, in each case inclusive of dividends paid at the rate of 7% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to October 31, 2018, the optional redemption valuation increases to the greater of a 17.5% internal rate of return or a return on investment of 2.0x. The preferred shares are redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of December 31, 2011, the redemption price, and the liquidation preference, was $1,400 per preferred share. CHK Utica is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. CHK Utica also receives its proportionate share of the benefit of the drilling carry associated with our joint venture with Total in the Utica Shale. See Note 11 for further discussion of the joint venture.

The CHK Utica investors' right to receive, proportionately, a 3% ORRI in the first 1,500 net wells drilled on our Utica Shale leasehold is subject to an increase to 4% in any year in which we do not meet our commitment to drill the wells subject to the ORRI obligation, which runs from 2012 through 2023. However, in no event would we deliver to investors more than a total ORRI of 3% of 1,500 net wells. If at any time we hold fewer net acres than would enable us to drill all then-remaining net wells on 150-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining net wells. We retain the right to repurchase the investors' right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining net wells once we have drilled a minimum of 1,300 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the future conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our natural gas and oil properties. For 2011, approximately $10 million of income was attributable to the noncontrolling interests of CHK Utica.

Chesapeake Granite Wash Trust. In November 2011, Chesapeake Granite Wash Trust (the Trust) issued 23,000,000 common units representing beneficial interests in the Trust at a price of $19.00 per common unit in its initial public offering. The common units are listed on the New York Stock Exchange and trade under the symbol "CHKR". We own an approximate 51% beneficial interest in the Trust, including 12,062,500 common units and 11,687,500 subordinated units. The Trust has a total of 46,750,000 units outstanding.

In connection with the initial public offering of the Trust, we conveyed royalty interests to the Trust that entitled the Trust to receive: (i) 90% of the proceeds (after deducting post production expenses and any applicable taxes) that we receive from the production of hydrocarbons from 69 producing wells, and, (ii) 50% of the proceeds (after deducting post production expenses and any applicable taxes) in 118 development wells to be drilled on approximately 45,400 gross acres (28,700 net acres) in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma. Pursuant to the terms of a development agreement with the Trust, we are obligated to drill, or cause to

be drilled, the development wells at our own expense prior to June 30, 2016, and the Trust will not be responsible for any costs related to the drilling of the development wells or any other operating or capital costs of the Trust properties. In addition, we granted to the Trust a lien on our remaining royalty interests in the development wells in order to secure our drilling obligation to the Trust, although the maximum amount that may be recovered by the Trust under such lien could not exceed $263 million initially and is proportionately reduced as we fulfill our drilling obligation over time. As of December 31, 2011, we had drilled 11.46 development wells and the maximum amount recoverable under the drilling support lien was approximately $237 million.

The subordinated units we hold in the Trust are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is no less than 80% of the target distribution for the corresponding quarter (subordination threshold). If there is not sufficient cash to fund such a distribution on all of the Trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. In exchange for agreeing to subordinate a portion of our Trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the underlying properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter is 20% greater than the target distribution for such quarter (incentive threshold). The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. At the end of the fourth full calendar quarter following Chesapeake's satisfaction of its drilling obligation with respect to the development wells, the subordinated units will automatically convert into common units on a one-for-one basis and Chesapeake's right to receive incentive distributions will terminate. After such time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share on a pro rata basis in the Trust's distributions.

We have determined that the Trust constitutes a VIE and that Chesapeake is the primary beneficiary. As a result, the Trust is included in our consolidated financial statements. As of December 31, 2011, $380 million was recorded as a noncontrolling interest on our consolidated balance sheet representing the public unitholders' investment in common units of the Trust. For the period from the initial public offering to December 31, 2011, approximately $5 million of income was attributable to the Trust's noncontrolling interests in our consolidated statement of operations. See Note 13 for further discussion of VIEs.

Cardinal Gas Services. Cardinal Gas Services, L.L.C. (Cardinal), an unrestricted, non-guarantor consolidated subsidiary was formed in December 2011 to acquire, develop, operate and own midstream assets in the Utica Shale. In exchange for the contribution of approximately $14 million in midstream assets, we received 66% of the outstanding membership units of Cardinal. In exchange for approximately $5 million, Total E&P USA, Inc. (Total) received 25% of the outstanding membership units and in exchange for approximately $2 million, CGAS Properties, L.P. (CGAS), an affiliate of Enervest, Ltd., received 9% of the membership units. The contributions from Total and CGAS were recorded as noncontrolling interests. Each member is responsible for its proportionate share of capital costs. As of December 31, 2011, the noncontrolling interest balance on the consolidated balance sheet associated with the contributions from Total and GCAS was approximately $7 million. There was no income (loss) attributable to noncontrolling interests in Cardinal in 2011.

9. Derivatives and Hedging Activities

Natural Gas and Oil Derivatives

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. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives. As of December 31, 2011 and 2010, our natural gas and oil derivative instruments were comprised of the following types of instruments:

- *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.
- *Swaptions:* Chesapeake sells swaptions to counterparties that allow them, on a specific date, to extend an existing fixed-price swap for a certain period of time.
- *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. Our basis protection swaps 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.

All of our derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The estimated fair values of our natural gas and oil derivative instruments as of December 31, 2011 and 2010 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2011		December 31, 2010	
	Volume	Fair Value	Volume	Fair Value
		($ in millions)		($ in millions)
Natural gas (tbtu):				
Fixed-price swaps	—	$ —	1,035	$ 1,307
Call options	1,357	(284)	1,478	(701)
Put options	—	—	(51)	(59)
Basis protection swaps	106	(42)	173	(55)
Total natural gas	1,463	(326)	2,635	492
Oil (mmbbl):				
Fixed-price swaps	14.9	15	4.4	(31)
Call options	94.7	(1,282)	64.2	(1,129)
Swaptions	7.8	(53)	—	—
Fixed-price knockout swaps	0.8	7	1.8	19
Total oil	118.2	(1,313)	70.4	(1,141)
Total estimated fair value		$ (1,639)		$ (649)

Pursuant to accounting guidance for derivatives and hedging, certain derivatives qualify for designation as cash flow hedges. Following this guidance, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales. 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 within natural gas and oil sales.

The components of natural gas and oil sales for the years ended December 31, 2011, 2010 and 2009 are presented below.

	Years Ended December 31,		
	2011	2010	2009
		($ in millions)	
Natural gas and oil sales	$ 5,259	$ 4,248	$ 3,291
Gains (losses) on natural gas and oil derivatives	772	1,422	1,722
Gains (losses) on ineffectiveness of cash flow hedges	(7)	(23)	36
Total natural gas and oil sales	$ 6,024	$ 5,647	$ 5,049

Based upon market prices at December 31, 2011, we expect to transfer approximately $17 million of net gain included in accumulated other comprehensive income during the next 12 months in the related month of production. All commodity derivative instruments as of December 31, 2011 are expected to mature by December 31, 2022.

We have a multi-counterparty secured hedging facility with 18 counterparties that have committed to provide approximately 6.5 tcfe of hedging capacity for commodity price derivatives and 6.5 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.5 billion under the terms of the facility. As of December 31, 2011, we had hedged under the facility 2.1 tcfe of our future production with price derivatives and 0.1 tcfe with basis derivatives. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and natural gas liquids price and basis derivative instruments 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 certain 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 derivative instruments. In addition, there are volume-based sub-limits for natural gas, oil and natural gas liquids derivative instruments. 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 derivative instruments 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.

Interest Rate Derivatives

To mitigate a portion of our exposure to volatility in interest rates related to our senior notes and bank credit facilities, we enter into interest rate derivatives. As of December 31, 2011 and 2010, our interest rate derivative instruments were comprised of the following types of instruments:

- *Swaps*: Chesapeake enters into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and pay a fixed interest rate) to manage our interest rate exposure related to our bank credit facilities borrowings.
- *Call Options*: Occasionally we sell call options for a premium when we think it is more likely that the option will expire unexercised. The option allows the counterparty to terminate a pre-determined open swap on a specific date.
- *Swaptions*: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a pre-determined swap with us on a specific date.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The notional amount and the estimated fair value of our interest rate derivatives outstanding as of December 31, 2011 and 2010 are provided below.

	December 31, 2011		December 31, 2010	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate:				
Swaps	$ 1,050	$ (42)	$ 1,900	$ (54)
Call options	—	—	250	(2)
Swaptions	300	—	500	(13)
Totals	$ 1,350	$ (42)	$ 2,650	$ (69)

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense in the consolidated statements of operations. The components of interest expense for the years ended December 31, 2011, 2010 and 2009 are presented below.

	Years Ended December 31,		
	2011	2010	2009
	($ in millions)		
Interest expense on senior notes	$ 653	$ 718	$ 765
Interest expense on credit facilities	70	61	60
(Gains) losses on interest rate derivatives	14	(80)	(114)
Amortization of loan discount and other	39	36	35
Capitalized interest	(732)	(716)	(633)
Total interest expense	$ 44	$ 19	$ 113

We have terminated certain fair value hedges related to senior notes. Gains and losses related to these terminated hedges will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next nine years, we will recognize $28 million in gains related to such transactions.

Foreign Currency Derivatives

In December 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 cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. As a result, we reclassified a loss of $38 million from accumulated other comprehensive income to the consolidated statement of operations, $20 million of which related to the unwound notional amount and was included in losses on purchases or exchanges of debt, and $18 million of which related to future interest associated with the unwound principal and was included in interest expense. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay Chesapeake €11 million and Chesapeake pays the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €344 million and Chesapeake will

pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swaps, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swaps qualify as cash flow hedges. The fair values of the cross currency swaps are recorded on the consolidated balance sheet as a liability of $38 million at December 31, 2011. The euro-denominated debt in long-term debt has been adjusted to $446 million at December 31, 2011 using an exchange rate of $1.2973 to €1.00.

Additional Disclosures Regarding Derivative Instruments and Hedging Activities

In accordance with accounting guidance for derivatives and hedging, to the extent that a legal right of set-off exists, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying consolidated balance sheets. Derivative instruments reflected as current in the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the respective balance sheet dates. The derivative settlement amounts are not due until the month in which the related underlying hedged transaction occurs. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivative is deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statements of cash flows.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table presents the fair value and location of each classification of derivative instrument included in the consolidated balance sheets as of December 31, 2011 and 2010 on a gross basis without regard to same-counterparty netting:

		Fair Value	
	Balance Sheet Location	December 31, 2011	December 31, 2010
		($ in millions)	
Asset Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$ —	$ 307
Commodity contracts	Long-term derivative instruments	—	12
Total		—	319
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	54	921
Commodity contracts	Long-term derivative instruments	1	229
Total		55	1,150
Liability Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	—	(59)
Interest rate contracts	Long-term derivative instruments	—	(25)
Foreign currency contracts	Long-term derivative instruments	(38)	(43)
Total		(38)	(127)
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(232)	(222)
Commodity contracts	Long-term derivative instruments	(1,462)	(1,837)
Interest rate contracts	Short-term derivative instruments	—	(15)
Interest rate contracts	Long-term derivative instruments	(42)	(29)
Total		(1,736)	(2,103)
Total derivative instruments		$ (1,719)	$ (761)

A consolidated summary of the effect of derivative instruments on the consolidated statements of operations for the years ended December 31, 2011 and 2010 is provided below, separating fair value, cash flow and non-qualifying derivatives.

Fair Value Hedges

For interest rate derivative instruments designated as fair value hedges, the fair values of the hedges are recorded on the consolidated balance sheets as assets or liabilities, with corresponding offsetting adjustments to the debt's carrying value. Our qualifying interest rate swaps are considered 100% effective and therefore no ineffectiveness was recorded for the periods presented below. Changes in the fair value of non-qualifying interest rate derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are currently reported in the consolidated statements of operations within interest expense.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table presents the gain (loss) recognized in the consolidated statements of operations for instruments designated as fair value derivatives:

		Years Ended December 31,		
Fair Value Derivatives	**Location of Gain (Loss)**	**2011**	**2010**	**2009**
			($ in millions)	
Interest rate contracts	Interest expense[(a)]	$ 16	$ 20	$ 37

We include the expense on the hedged item (i.e., fixed-rate borrowings) in the same line item – interest expense – as the offsetting gain or loss on the related interest rate swap listed above. For the years ended December 31, 2011, 2010 and 2009, this expense was $23 million, $19 million and $71 million respectively.

Cash Flow Hedges

A reconciliation of the components of accumulated other comprehensive income (loss) in the consolidated statements of stockholders' equity related to our cash flow hedges is presented below.

	Years Ended December 31,					
	2011		**2010**		**2009**	
	Before Tax	**After Tax**	**Before Tax**	**After Tax**	**Before Tax**	**After Tax**
			($ in millions)			
Balance, beginning of period	$ (291)	$ (181)	$ 134	$ 84	$ 505	$ 315
Net change in fair value	368	228	364	226	1,054	654
Gains reclassified to income	(364)	(225)	(789)	(491)	(1,425)	(885)
Balance, end of period	$ (287)	$ (178)	$ (291)	$ (181)	$ 134	$ 84

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table presents the pre-tax gain (loss) recognized in, and reclassified from, accumulated other comprehensive income (AOCI) related to instruments designated as cash flow derivatives:

Cash Flow Derivatives	Location of Gain (Loss)	Years Ended December 31, 2011	2010	2009
			($ in millions)	
Gain (Loss) Recognized in AOCI (Effective Portion)				
Commodity contracts	AOCI	$ 392	$ 386	$ 958
Foreign currency contracts	AOCI	(24)	(22)	96
		$ 368	$ 364	$ 1,054
Gain (Loss) Reclassified from AOCI (Effective Portion)				
Commodity contracts	Natural gas and oil sales	$ 402	$ 789	$ 1,425
Foreign currency contracts	Interest expense	(18)	—	—
Foreign currency contracts	Loss on purchase of debt	(20)	—	—
		$ 364	$ 789	$ 1,425
Gain (Loss) Recognized in Income				
Commodity contracts				
Ineffective portion	Natural gas and oil sales	$ (7)	$ (23)	$ 36
Amount initially excluded from effectiveness testing	Natural gas and oil sales	22	4	157
		$ 15	$ (19)	$ 193

Non-Qualifying Derivatives

The following table presents the gain (loss) recognized in the consolidated statements of operations for instruments not qualifying as cash flow or fair value derivatives:

Non-Qualifying Derivatives	Location of Gain (Loss)	Years Ended December 31, 2011	2010	2009
			($ in millions)	
Commodity contracts	Natural gas and oil sales	$ 348	$ 629	$ 139
Interest rate contracts	Interest expense	(12)	60	77
	Total	$ 336	$ 689	$ 216

Credit Risk

Derivative instruments enable us to mitigate 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 counterparties that are rated investment-grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. On December 31, 2011, our derivative instruments were spread among 17 counterparties. Additionally, the counterparties under our multi-counterparty secured

hedging facility described previously are required to secure their natural gas and oil derivative obligations in excess of defined thresholds. We use this facility for the majority of our natural gas, oil and natural gas liquids derivatives.

10. Supplemental Disclosures About Natural Gas and Oil Producing Activities (Unaudited)

Net Capitalized Costs

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

	December 31,	
	2011	2010
	($ in millions)	
Natural gas and oil properties:		
Proved	$ 41,723	$ 38,952
Unproved	16,685	14,469
Total	58,408	53,421
Less accumulated depreciation, depletion and amortization	(27,208)	(25,595)
Net capitalized costs	$ 31,200	$ 27,826

Unproved properties not subject to amortization at December 31, 2011, 2010 and 2009 consisted mainly of leasehold acquired through significant natural gas and oil property acquisitions and through direct purchases of leasehold. We capitalized approximately $727 million, $711 million and $627 million of interest during 2011, 2010 and 2009, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full cost pool. We will continue to evaluate our unproved properties and seismic projects, and although the timing of the ultimate evaluation or disposition of the properties cannot be determined, we can expect the majority of our unproved properties to be transferred into the amortization base over the next five years.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Costs Incurred in Natural Gas and Oil Drilling and Completion, Acquisitions and Divestitures

Costs incurred in natural gas and oil drilling and completion, acquisition and divestiture activities which have been capitalized are summarized as follows:

	December 31,		
	2011	2010	2009
		($ in millions)	
Drilling and completion costs:			
Development[a]	$ 5,495	$ 4,739	$ 2,729
Exploratory[b][c]	2,260	872	813
Asset retirement obligation and other	3	2	(2)
	7,758	5,613	3,540
Acquisition costs:			
Unproved properties[d]	4,736	6,953	2,793
Proved properties	48	243	61
	4,784	7,196	2,854
Proceeds from divestitures:			
Unproved properties	(4,943)	(1,524)	(1,265)
Proved properties	(2,612)	(2,876)	(461)
	(7,555)	(4,400)	(1,726)
Total	$ 4,987	$ 8,409	$ 4,668

(a) Includes capitalized internal costs of $399 million, $353 million and $337 million, respectively.

(b) Includes capitalized internal costs of $18 million, $16 million and $22 million, respectively.

(c) Includes related capitalized interest of $18 million, $24 million and $29 million, respectively.

(d) Includes related capitalized interest of $709 million, $687 million and $598 million, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Results of Operations from Natural Gas and Oil Producing Activities

Chesapeake's results of operations from natural gas and oil producing activities are presented below for 2011, 2010 and 2009. The following table includes revenues and expenses associated directly with our natural gas and oil producing activities. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our natural gas and oil operations.

	Years Ended December 31,		
	2011	2010	2009
		($ in millions)	
Natural gas and oil sales	$ 6,024	$ 5,647	$ 5,049
Production expenses	(1,073)	(893)	(876)
Production taxes	(192)	(157)	(107)
Impairment of natural gas and oil properties	—	—	(11,000)
Depletion and depreciation	(1,632)	(1,394)	(1,371)
Imputed income tax provision[(a)]	(1,220)	(1,233)	3,114
Results of operations from natural gas and oil producing activities	$ 1,907	$ 1,970	$ (5,191)

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

Natural Gas and Oil Reserve Quantities

Chesapeake's petroleum engineers and independent petroleum engineering firms estimated all of our proved reserves as of December 31, 2011, 2010 and 2009. Independent petroleum engineering firms estimated an aggregate of 77%, 78% and 83% of our estimated proved reserves (by volume), as of December 31, 2011, 2010 and 2009, respectively, as set forth below.

	December 31,		
	2011	2010	2009
Netherland, Sewell & Associates, Inc.	42%	58%	59%
Ryder Scott Company, L.P.	19%	6%	7%
Lee Keeling and Associates, Inc.	9%	7%	10%
Data & Consulting Services, Division of Schlumberger Technology Corporation	7%	7%	7%

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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. Based on reserve reporting rules effective December 31, 2009, the price is calculated using 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. 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 the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) 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 data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural 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: (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Developed natural gas and oil reserves are reserves of any category 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.

The information below on our natural gas and oil reserves is presented in accordance with regulations prescribed by the U.S. Securities and Exchange Commission as in effect as of the date of such estimates. Our reserve estimates are generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates will change as future information becomes available and as commodity prices change. Such changes could be material and could occur in the near term.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Presented below is a summary of changes in estimated reserves of Chesapeake for 2011, 2010 and 2009.

	Gas (bcf)	Oil[a] (mmbbl)	Total (bcfe)
December 31, 2011			
Proved reserves, beginning of period	15,455	273.4	17,096
Extensions, discoveries and other additions	4,156	254.6	5,683
Revisions of previous estimates	(361)	51.8	(50)
Production	(1,004)	(31.7)	(1,194)
Sale of reserves-in-place	(2,754)	(3.8)	(2,776)
Purchase of reserves-in-place	23	1.2	30
Proved reserves, end of period[b]	15,515	545.5	18,789
Proved developed reserves:			
Beginning of period	8,246	149.3	9,143
End of period	8,578	254.6	10,106
December 31, 2010			
Proved reserves, beginning of period	13,510	124.0	14,254
Extensions, discoveries and other additions	4,678	70.0	5,098
Revisions of previous estimates	(445)	104.6	183
Production	(925)	(18.4)	(1,035)
Sale of reserves-in-place	(1,426)	(11.2)	(1,493)
Purchase of reserves-in-place	63	4.4	89
Proved reserves, end of period	15,455	273.4	17,096
Proved developed reserves:			
Beginning of period	7,859	78.8	8,331
End of period	8,246	149.3	9,143
December 31, 2009			
Proved reserves, beginning of period	11,327	120.6	12,051
Extensions, discoveries and other additions	4,530	27.1	4,693
Revisions of previous estimates	(1,335)	(10.3)	(1,397)
Production	(835)	(11.8)	(906)
Sale of reserves-in-place	(209)	(1.8)	(220)
Purchase of reserves-in-place	32	0.2	33
Proved reserves, end of period	13,510	124.0	14,254
Proved developed reserves:			
Beginning of period	7,582	84.9	8,091
End of period	7,859	78.8	8,331

(a) Includes NGLs.

(b) Includes 130 bcf of natural gas and 18.9 mmbbls of oil reserves owned by the Chesapeake Granite Wash Trust, 64 bcf and 9.3 mmbbls of which are attributable to the noncontrolling interest holders.

During 2011, Chesapeake acquired approximately 30 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $48 million, and we sold 2.776 tcfe of our proved reserves for approximately $2.612 billion, including divestitures related to our Fayetteville Shale assets, a volumetric production payment transaction and other non-core asset sales. During 2011, we recorded negative revisions of 50 bcfe to the December 31, 2010 estimates of our reserves. Included in the revisions were 273 bcfe of positive revisions to producing properties and retained proved reserves estimates, offset by 337 bcfe of negative revisions associated with the deletion of proved undeveloped reserves no longer consistent with our development plans. In addition, we had 14 bcfe of positive revisions resulting from higher oil prices using the average of the first-day-of-the-month prices for the twelve months ended December 31, 2011, compared to the twelve months ended December 31, 2010. Higher prices increase the economic lives of the underlying natural gas and oil properties and thereby increase the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2011 were $4.12 per mcf and $95.97 per barrel before price differentials.

During 2010, Chesapeake acquired approximately 89 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $243 million (primarily in five separate transactions of greater than $10 million each), and we sold 1.493 tcfe of our proved reserves for approximately $2.876 billion, including divestitures related to three volumetric production payment transactions, the sale of a portion of our Barnett Shale assets and other non-core asset sales. During 2010, we recorded positive revisions of 183 bcfe to the December 31, 2009 estimates of our reserves. Included in the revisions were 189 bcfe of positive revisions resulting from higher natural gas prices using the average of the first-day-of-the-month prices for the twelve months ended December 31, 2010, compared to the twelve months ended December 31, 2009, and 6 bcfe of downward revisions resulting from changes to previous estimates. Higher prices extend the economic lives of the underlying natural gas and oil properties and thereby increase the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2010 were $4.38 per mcf and $79.42 per barrel before price differentials.

During 2009, Chesapeake acquired approximately 33 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $61 million (primarily in two separate transactions of greater than $10 million each) and we sold 220 bcfe of our proved reserves for approximately $576 million. During 2009, we recorded downward revisions of 1.397 tcfe to the December 31, 2008 estimates of our reserves. Included in the revisions were 952 bcfe of downward revisions resulting from lower natural gas prices using the average of the first-day-of-the-month prices for the twelve months ended December 31, 2010 compared to the spot price as of December 31, 2008, and 445 bcfe of downward revisions resulting from changes to previous estimates. Lower prices decrease the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2009 were $3.87 per mcf and $61.14 per barrel before price differentials.

Standardized Measure of Discounted Future Net Cash Flows

Accounting Standards Topic 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Chesapeake has followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2011, 2010 and 2009 were determined by applying the average of the first-day-of-the-month prices for the 12 months of the year and year-end costs to the estimated quantities of natural gas and oil to be

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

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

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

	Years Ended December 31,		
	2011	2010	2009
		($ in millions)	
Future cash inflows	$ 85,537[a]	$ 69,616[b]	$ 49,322[c]
Future production costs	(23,022)	(20,384)	(16,620)
Future development costs	(14,471)	(11,602)	(8,881)
Future income tax provisions	(12,266)	(6,859)	(4,106)
Future net cash flows	35,778	30,771	19,715
Less effect of a 10% discount factor	(20,148)	(17,588)	(11,512)
Standardized measure of discounted future net cash flows	$ 15,630	$ 13,183	$ 8,203

(a) Calculated using prices of $4.12 per mcf of natural gas and $95.97 per barrel of oil, before field differentials.

(b) Calculated using prices of $4.38 per mcf of natural gas and $79.42 per barrel of oil, before field differentials.

(c) Calculated using prices of $3.87 per mcf of natural gas and $61.14 per barrel of oil, before field differentials.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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

	Years Ended December 31,		
	2011	2010	2009
	($ in millions)		
Standardized measure, beginning of period[(a)]	$ 13,183	$ 8,203	$ 11,833
Sales of natural gas and oil produced, net of production costs[(b)]	(3,993)	(3,199)	(2,307)
Net changes in prices and production costs	512	3,337	(7,297)
Extensions and discoveries, net of production and development costs	9,139	5,580	2,374
Changes in future development costs	667	173	1,910
Development costs incurred during the period that reduced future development costs	680	717	650
Revisions of previous quantity estimates	(708)	199	(1,290)
Purchase of reserves-in-place	50	255	41
Sales of reserves-in-place	(2,083)	(2,235)	(377)
Accretion of discount	1,515	945	1,560
Net change in income taxes	(2,286)	(716)	2,521
Changes in production rates and other	(1,046)	(76)	(1,415)
Standardized measure, end of period[(a)(c)]	$ 15,630	$ 13,183	$ 8,203

(a) The impact of cash flow hedges has not been included in any of the periods presented.

(b) Excluding gains (losses) on derivatives.

(c) Effect of noncontrolling interest of Chesapeake Granite Wash Trust is immaterial.

11. Acquisitions and Divestitures

Acquisition of Bronco Drilling

In June 2011, we acquired Bronco Drilling Company, Inc., a publicly traded contract land drilling services company, for an aggregate purchase price of approximately $339 million, or $11.00 per share of Bronco common stock. The acquisition was accounted for as a business combination which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. Pro forma financial information is not presented as it would not be materially different from the information presented in the consolidated statement of operations.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table summarizes the assets acquired and liabilities assumed:

	As of June 6, 2011 ($ in millions)
Current assets	$ 53
Drilling rigs and equipment	290
Goodwill	29
Intangible assets	10
Other	15
Total assets acquired	397
Current liabilities	32
Long-term liabilities	1
Deferred income taxes	25
Total liabilities assumed	58
Net assets acquired	$ 339

The acquisition date fair value of the consideration transferred was $339 million in cash. We received carryover tax basis in Bronco's assets and liabilities because the acquisition was not a taxable transaction under the Internal Revenue Code. Based upon the purchase price allocation, a step-up in basis related to the assets acquired from Bronco resulted in a net deferred tax liability of approximately $25 million. We recorded goodwill of $29 million, which represents the amount of the consideration transferred in excess of the fair values assigned to the individual assets acquired and liabilities assumed. Goodwill is primarily attributable to operational and cost synergies expected to be realized from the acquisition by integrating Bronco's drilling rigs and assembled workforce and is included in other long-term assets on our consolidated balance sheets. Goodwill was assigned to drilling rig operations within our oilfield services segment which is discussed in Note 17. Goodwill recorded in the acquisition is not subject to amortization but will be tested annually for impairment on October 1. None of the goodwill is deductible for tax purposes. The drilling rigs and equipment we acquired from Bronco are now owned by Nomac Drilling, L.L.C., our drilling subsidiary of COO.

Fayetteville Shale Asset Sale

In March 2011, we sold all of our Fayetteville Shale assets in central Arkansas to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited (NYSE:BHP; ASX:BHP), for net proceeds of approximately $4.65 billion in cash. The properties sold consisted of approximately 487,000 net acres of leasehold, net production at closing of approximately 415 million cubic feet of natural gas equivalent per day and midstream assets consisting of approximately 420 miles of pipeline. Of the total proceeds received, $350 million was allocated to our Fayetteville Shale midstream assets and a $7 million gain was recorded for the divestiture of those assets. The remainder of the proceeds was allocated to our Fayetteville Shale natural gas and oil properties. Under full cost accounting rules, we accounted for the sale of our Fayetteville Shale natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss. As part of the transaction, Chesapeake agreed to provide technical and business services for up to one year for BHP Billiton's Fayetteville properties for an agreed-upon fee.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Joint Ventures

As of December 31, 2011, we had entered into seven significant joint ventures pursuant to which we sold a portion of our leasehold, producing properties and other assets located in six different resource plays and received cash of $7.1 billion in the aggregate and commitments for future drilling and completion cost sharing totaling $9.0 billion. These transactions have allowed us to recover much or all of our initial leasehold investments and reduce our ongoing capital costs in these plays. For accounting purposes, initial cash proceeds from these joint venture transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. The transactions are detailed below.

Primary Play	Joint Venture Partner[a]	Joint Venture Date	Interest Sold	Cash Proceeds Received at Closing	Total Drilling Carries	Drilling Carries Remaining[b]
					($ in millions)	
Utica	TOT	December 2011	25.0%	$ 610	$ 1,422	$ 1,422
Niobrara	CNOOC	February 2011	33.3%	570	697	570
Eagle Ford & Pearsall	CNOOC	November 2010	33.3%	1,120	1,080	144
Barnett	TOT	January 2010	25.0%	800	1,404[c]	—
Marcellus	STO	November 2008	32.5%	1,250	2,125	223
Fayetteville	BP	September 2008	25.0%	1,100	800	—
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508[d]	—
				$ 7,100	$ 9,036	$ 2,359

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

(b) As of December 31, 2011. The Utica carry must be used by January 2018, the Niobrara carry must be used by December 2014, the Eagle Ford and Pearsall carry must be used by March 2013 and the Marcellus carry must be used by November 2012. We expect to fully utilize these drilling carry commitments prior to expiration. See Note 4 for further discussion.

(c) In conjunction with an agreement requiring us to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012, TOT accelerated the payment of its remaining joint venture drilling carry in exchange for an approximate 9% reduction in the total amount of drilling carry obligation owed to us at that time. As a result, in October 2011, we received $471 million in cash from TOT, which included $46 million of carry obligation billed and $425 million for the remaining carry obligation. In January 2012, Chesapeake and TOT agreed to reduce the minimum rig count from 12 to six rigs.

(d) In September 2009, PXP accelerated the payment of its remaining carry in exchange for an approximate 12% reduction to the remaining drilling carry obligation owed to us at that time.

During 2011, 2010 and 2009, our drilling and completion costs included the benefit of approximately $2.570 billion, $1.151 billion and $1.153 billion, respectively, in drilling and completion carries paid by our joint venture partners, CNOOC, TOT, STO, BP and PXP.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

During 2011, 2010 and 2009, as part of our joint venture agreements with CNOOC, TOT, STO and PXP, we sold interests in additional leasehold in the Niobrara, Eagle Ford and Pearsall, Barnett, Marcellus and Haynesville and Bossier shale plays to our joint venture partners for approximately $511 million, $440 million and $100 million, respectively. For accounting purposes, cash proceeds from these transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Volumetric Production Payments

From time to time, we have monetized certain of our producing assets which are located in more mature producing regions through the sale of volumetric production payments (VPPs). A VPP is 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. We retain drilling rights on the properties below currently producing intervals and outside of producing well bores. We also retain all production beyond the specified volumes sold in the transaction.

We have completed the following volumetric production payment (VPP) transactions since 2007:

Date of VPP	Region	Proceeds	Proved Reserves (bcfe)	$ / mcfe	Original Term
		($ in millions)	(at time of sale)		(years)
May 2011	Mid-Continent	$ 853	177	$ 4.82	10
September 2010	Barnett Shale	1,150	390	$ 2.93	5
June 2010	Permian Basin	335	38	$ 8.73	10
February 2010	East Texas and the Texas Gulf Coast	180	46	$ 3.95	10
August 2009	South Texas	370	68	$ 5.46	7.5
December 2008	Anadarko and Arkoma Basins	412	98	$ 4.19	8
August 2008	Anadarko Basin	600	93	$ 6.38	11
May 2008	Texas, Oklahoma and Kansas	622	94	$ 6.53	11
December 2007	Kentucky and West Virginia	1,100	208	$ 5.29	15
		$ 5,622	1,212	$ 4.64	

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

Sale of Marcellus Midstream Assets

In December 2011, our wholly owned midstream subsidiary, CMD sold its wholly owned subsidiary, Appalachia Midstream Services, L.L.C. (AMS), which held substantially all of our Marcellus Shale midstream assets, to our affiliate, CHKM, for total consideration of $879 million, subject to a customary post-closing working capital adjustment, and recorded a gain of $436 million. At closing, we received cash of $600 million and 9,791,605 common units of CHKM that had a value at closing of $279 million. The stock consideration increased our ownership in CHKM from 42.3% to 46.1%. The assets sold included an approximate 47% ownership of an integrated system of assets that consist of 200 miles of pipeline in the Marcellus Shale. In addition, CMD has committed to pay CHKM any quarterly shortfall between the actual EBITDA from the assets sold and specified quarterly targets, which total $100 million in 2012 and $150 million in 2013. We have recorded the fair value of this guarantee as a liability. See Note 4 for further discussion of this commitment. We, and other producers in the area, have 15-year fixed fee gathering and compression agreements with AMS that include significant acreage dedications and an annual fee redetermination.

Sale of Springridge Gathering System

In December 2010, CMD sold its Springridge natural gas gathering system and related facilities in the Haynesville Shale to CHKM for $500 million and recorded a gain on the sale of $157 million. In connection with this transaction, CHKM and certain Chesapeake subsidiaries entered into ten-year gathering and compression agreements covering Chesapeake's and other producers' 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 through 2013 and periodic rate redetermination.

12. Investments

At December 31, 2011 and 2010, we had the following investments:

	Approximate % Owned	Accounting Method	Carrying Value December 31, 2011	Carrying Value December 31, 2010
			($ in millions)	
Chesapeake Midstream Partners, L.P.	46%	Equity	$ 987	$ 695
FTS International, LLC	30%	Equity	235	311
Chaparral Energy, Inc.	20%	Equity	143	133
Clean Energy Fuels Corp.	—	Cost	50	—
Sundrop Fuels, Inc.	25%	Equity	34	—
Gastar Exploration Ltd.	10%	Fair Value	22	29
Other	—	—	60	40
			$ 1,531	$ 1,208

Chesapeake Midstream Partners, L.P. Chesapeake Midstream Partners, L.P. (NYSE:CHKM) is a master limited partnership which we and Global Infrastructure Partners-A, L.P. and affiliated funds managed by Global Infrastructure Management, LLC and certain of their respective subsidiaries and affiliates (collectively, GIP) formed in 2010 to own, operate, develop and acquire gathering systems and other midstream energy assets. CHKM completed its initial public offering on August 3, 2010. As of December 31, 2011, public security holders, GIP and Chesapeake owned 23.5%, 30.4% and 46.1%,

respectively, of all outstanding CHKM limited partner interests. CHKM 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. CHKM is principally focused on natural gas gathering, the first segment of midstream energy infrastructure that connects natural gas produced at the wellhead to third-party takeaway pipelines. CHKM currently operates in Texas, Louisiana, Oklahoma, Kansas, Arkansas, Pennsylvania and West Virginia and provides gathering, treating and compression services to Chesapeake and other producers under long-term, fixed-fee contracts. See Note 13 for further discussion of CHKM.

In December 2011, through the sale of our wholly owned subsidiary, AMS to CHKM, we received 9,791,605 common units of CHKM and $600 million in cash consideration. The receipt of these units increased the cost basis of our investment by $279 million. We, along with GIP, each made an additional $3 million capital contribution to the general partner of CHKM to allow it to maintain its 2% general partner interest in CHKM as a result of CHKM's issuance of additional common units in connection with the AMS transaction.

During 2011, we recorded positive equity method adjustments of $83 million for our share of CHKM's income, received cash distributions of $85 million from CHKM and recorded accretion adjustments of $12 million related to our share of equity in excess of cost. The carrying value of our investment in CHKM is less than our underlying equity in net assets by approximately $156 million as of December 31, 2011. This difference is being accreted over the 20-year estimated useful lives of the underlying assets. See Note 13 for further discussion of CHKM.

FTS International, LLC. FTS International, LLC (FTS), based in Fort Worth, Texas, is a privately held parent company which, through its subsidiaries, provides pressure pumping and well stimulation to oil and gas companies. On May 6, 2011, there was a change in controlling ownership of FTS's predecessor, Frac Tech Holdings, LLC, which resulted in a recapitalization that increased our equity ownership from 26% to 30%. We also entered into a master frac services agreement that commits us to use certain services of FTS through 2014. See Note 4 for further discussion of this commitment.

In 2011, we recorded positive equity method adjustments of $133 million for our share of FTS's income, received cash distributions of $234 million from FTS and recorded accretion adjustments of $25 million. Based on the valuation of the net assets performed by FTS in conjunction with the change in controlling ownership, the carrying value of our investment in FTS is less than our underlying equity in FTS's net assets by approximately $868 million as of December 31, 2011. We allocated this difference to the tangible and intangible assets of FTS and will accrete the portion attributable to the non-goodwill assets over their estimated lives of nine years.

Chaparral Energy, Inc. Chaparral Energy, Inc., based in Oklahoma City, Oklahoma, is a private independent oil and natural gas company engaged in the production, acquisition and exploitation of oil and natural gas properties. During 2011, we recorded a $13 million adjustment related to our share of Chaparral's net gain and depreciation adjustments of $3 million related to the excess of our cost over our proportionate share of Chaparral's book equity. The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $54 million as of December 31, 2011. This excess is attributed to the natural gas and oil reserves held by Chaparral and is being amortized over the estimated life of these reserves based on a unit of production rate.

Due to the dramatic decrease in natural gas and oil prices at the end of 2008 and into 2009, as a result of the slowing worldwide economy we recognized an other than temporary impairment on our investment in Chaparral of $51 million in 2009.

Clean Energy Fuels Corp. In July 2011, we agreed to invest $150 million in newly issued convertible promissory notes of Clean Energy Fuels Corp. (Nasdaq:CLNE), based in Seal Beach, California. The investment is being made in three equal $50 million promissory notes, the first of which was issued in July 2011, with the remaining notes scheduled to be issued in June 2012 and June 2013. The notes bear interest at the annual rate of 7.5%, payable quarterly, and are convertible at our option into shares of Clean Energy's common stock at a 22.5% conversion premium, resulting in a conversion price of $15.80 per share. Under certain circumstances following the second anniversary of the issuance of a note, Clean Energy can force conversion of the debt. The entire principal balance of each note is due and payable seven years following issuance. Clean Energy will use our $150 million investment to accelerate its build-out of LNG fueling infrastructure for heavy-duty trucks at truck stops across interstate highways in the U.S.

Sundrop Fuels, Inc. In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Louisville, Colorado. The investment over the next two years will fund construction of a nonfood biomass-based "green gasoline" plant, capable of annually producing more than 40 million gallons of gasoline from natural gas and waste cellulosic material. The investment is intended to accelerate the development of an affordable, stable, room-temperature, natural gas-based fuel for immediate use in automobiles, diesel engine vehicles and aircraft. The first $35 million tranche of our investment was funded in July 2011 and the remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached by July 2013. The full investment will represent 50% of Sundrop Fuels' equity on a fully diluted basis. During 2011, we recorded a $1 million charge related to our share of Sundrop's net loss.

Gastar Exploration Ltd. Gastar Exploration Ltd. (NYSE Amex:GST), based in Houston, Texas, is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. During 2011, the common stock price of Gastar decreased from $4.30 per share to $3.18 per share. Our investment in Gastar has a historical cost basis of $89 million.

Due to the dramatic decrease in natural gas and oil prices at the end of 2008 and into 2009, as a result of the slowing worldwide economy, we recognized an other than temporary impairment on our investment in Gastar of $70 million, in March 2009.

Other. In 2011, Chesapeake NG Ventures Corporation, a wholly owned subsidiary, acquired 1 million common shares of Clean Energy Fuels Corp (NASDAQ:CLNE) at $10.00 per share. On December 31, 2011, the shares were trading at $12.46. We account for our investment as an available-for-sale investment which is carried at fair value. Additionally in 2011, our wholly owned subsidiary, Chesapeake Oilfield Services, L.L.C., made investments in transportation entities, furthering our goal for vertical integration, for a total of $17 million. These investments are accounted for using the equity method.

In 2010, we recorded a $16 million impairment of certain other equity investments. Our investees were impacted by the dramatic slowing of the worldwide economy and the tightening of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness 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 March 31, 2009 of $41 million.

13. Variable Interest Entities

In accordance with accounting guidance for consolidation, we consolidate the activities of VIEs of which we are the primary beneficiary. The primary beneficiary of a VIE is that variable interest holder possessing a controlling financial interest through (i) its power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (ii) its obligation to absorb losses or its right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether we own a variable interest in a VIE, we perform qualitative analysis of the entity's design, organizational structure, primary decision makers and relevant agreements.

Consolidated VIE

Chesapeake Granite Wash Trust. For discussion of the formation, operations and presentation of the Trust, please see *Noncontrolling Interests* in Note 8. The Trust is considered a VIE due to the lack of voting or similar decision-making rights by its equity holders regarding activities that have a significant effect on the economic success of the Trust. Our ownership in the Trust and our obligations under the development agreement and related drilling support lien constitute variable interests. We have determined that we are the primary beneficiary of the Trust as (i) we have the power to direct the activities that most significantly impact the economic performance of the Trust via our obligations to perform under the development agreement, and (ii) as a result of the subordination and incentive thresholds applicable to the subordinated units we hold in the Trust, we have the obligation to absorb losses and the right to receive residual returns that could potentially be significant to the Trust. As a result, we consolidate the Trust in our financial statements and the common units of the Trust owned by third parties are reflected as a noncontrolling interest.

The Trust is a consolidated entity whose legal existence is separate from Chesapeake and our other consolidated subsidiaries and the Trust is not a guarantor of any of Chesapeake's debt. The creditors or beneficial holders of the Trust have no recourse to the general credit of Chesapeake; however, we have certain obligations to the Trust through the development agreement that are secured by a drilling support lien on our retained interest in the development wells up to a specified maximum amount recoverable by the Trust, which could result in the Trust acquiring all or a portion of our retained interest in the development wells if we do not meet our drilling commitment. In consolidation, approximately $492 million of net oil and gas property assets, $32 million of current liabilities and $10 million in long-term liabilities were attributable to the Trust. We have presented parenthetically on the face of the consolidated balance sheet the assets of the Trust that can be used only to settle obligations of the Trust and the liabilities of the Trust for which creditors do not have recourse to the general credit of Chesapeake.

Unconsolidated VIE

Chesapeake Midstream Partners, L.P. We have an approximate 46% interest in CHKM through our ownership of common, general partner and subordinated units. CHKM focuses on unregulated business activities in service to both Chesapeake and third party natural gas producers and its revenues are generated from gathering, compression, dehydration and treating services. Certain Chesapeake employees provide services to CHKM through an employee secondment agreement and CHKM utilizes various support functions within Chesapeake, including accounting, human resources and information technology in return for certain cost reimbursements. As of December 31, 2011, common units owned by public security holders represented 23.5% of all outstanding limited partner interests, and Chesapeake and GIP held 46.1% and 30.4%, respectively, of all outstanding limited

partner interests. Of the limited partner units, approximately 51% and 77% of the units were subordinated for Chesapeake and GIP, respectively. The limited partners, collectively, have a 98% limited partner interest in CHKM, and Chesapeake and GIP each own 50% of the remaining 2% general partner interest.

The partnership agreement provides that, during the subordination period, the common units are entitled to distributions of available cash each quarter in an amount equal to the minimum quarterly distribution, which is $0.3375 per common unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash are permitted on the subordinated units. The subordination period will lapse at such time when the partnership has earned and paid at least $0.3375 per quarter on each common unit, subordinated unit and general partner unit for any three consecutive, non-overlapping four-quarter periods ending on or after June 30, 2013. Also, if the partnership has earned and paid at least 150% of the minimum quarterly distribution on each outstanding common unit, subordinated unit and general partner unit for each calendar quarter in a four-quarter period, the subordination period will terminate automatically. The subordination period will also terminate automatically if the general partner is removed without cause and the units held by the general partner and its affiliates are not voted in favor of removal. When the subordination period lapses or otherwise terminates, all remaining subordinated units will convert into common units on a one-for-one basis and the common units will no longer be entitled to arrearages. All subordinated units are held indirectly by Chesapeake and GIP.

CHKM is considered a VIE because of the significance of its operations to us and the contractual arrangements between Chesapeake and CHKM that pass certain economic risks to us which are disproportionate to our economic interest. These primarily include certain gas gathering agreements with CHKM pursuant to which we have committed to deliver annually specified minimum volumes of natural gas under firm transportation agreements, an EBITDA guarantee we issued to CHKM in conjunction with our December 2011 sale of AMS and the subordination of our units to those of other unitholders. Our ownership in CHKM, and our rights and commitments under our contractual arrangements with CHKM constitute variable interests. See *Other Commitments* in Note 4.

Because the general partner controls CHKM, we have determined that the power to direct the activities which are most significant to its economic performance are shared between us and GIP. Prior to 2010, we consolidated our investment and reported GIP's investment as a noncontrolling interest based on our conclusion that the disproportionate economics indicated we were the primary beneficiary. Effective January 1, 2010, in accordance with new authoritative guidance for VIEs, we began accounting for our investment under the equity method because the power to control the significant decisions of CHKM is shared with GIP. Adoption of this new guidance resulted in an after-tax cumulative effect charge to retained earnings of $142 million, which is reflected in our consolidated statement of equity for the year ended December 31, 2010. This charge reflects the difference between the carrying value of our initial investment and the fair value of our equity in the entity as of the formation date. See Note 12 for a discussion of the accounting for, and the carrying value of, our investment in CHKM. Also, see Note 11 for information regarding the sale of our Marcellus and Springridge midstream businesses to CHKM. For details regarding amounts paid and received from CHKM during 2011 and 2010, see Note 6.

Our risk of loss related to CHKM includes our investment balance and certain commitments to CHKM through the EBITDA guarantee and under our firm transportation agreements that could require us to make shortfall payments in the event we do not meet our minimum volume commitments. The creditors or other beneficial holders of CHKM common units have no other recourse to the general credit of Chesapeake.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

14. Restructuring Costs

In 2009, we restructured our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model the Company uses 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 reorganization include termination benefits, consolidating or closing facilities and relocating employees. In addition, we had certain other workforce reductions that resulted in termination benefits. A summary of Chesapeake's restructuring costs is presented below.

	Year Ended December 31, 2009
	($ in millions)
Termination and relocation costs	$ 22
Acceleration of restricted stock awards	9
Other associated costs	3
Total Restructuring Costs	$ 34

15. Fair Value Measurements

Certain financial instruments are reported at fair value on the consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses a market valuation approach based on available inputs and the following methods and assumptions to measure the fair values of its assets and liabilities, which may or may not be observable in the market.

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

Investments. The fair value of Chesapeake's investment in Gastar Exploration Ltd. (NYSE Amex: GST) and Clean Energy Fuels Corporation (NASDAQ:CLNE) common stock is based on a quoted market price.

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

Derivatives. The fair values of our commodity derivatives, interest rate swaps and cross currency swaps are based on third-party pricing models which utilize inputs that are either readily available in the public market, such as natural gas and oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by our counterparties for reasonableness. Since commodity, interest rate and cross currency swaps do not include optionality and therefore have no unobservable inputs, they are classified as Level 2. All other derivatives have some level of unobservable input, such as volatility curves, and are

therefore classified as Level 3. For interest rate options and swaptions, we use the fair value estimates provided by our respective counterparties. These values are reviewed internally for reasonableness using future interest rate curves and time to maturity. Derivatives are also subject to the risk that counterparties will be unable to meet their obligations. We factor in non-performance risk in the valuation of our derivatives using current published credit default swap rates. To date this has not had a material impact on the values of our derivatives.

Debt. The fair value of certain of our long-term debt is based on the face amount of that debt along with the value of related interest rate swaps.

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2011:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
	($ in millions)			
Financial Assets (Liabilities):				
Cash equivalents	$ 396	$ —	$ —	$ 396
Investments	34	—	—	34
Other long-term assets	61	—	—	61
Other long-term liabilities	(62)	—	—	(62)
Derivatives:				
Commodity assets	—	46	9	55
Commodity liabilities	—	(31)	(1,663)	(1,694)
Interest rate liabilities	—	(42)	—	(42)
Foreign currency liabilities	—	(38)	—	(38)
Total derivatives	—	(65)	(1,654)	(1,719)
Total	$ 429	$ (65)	$ (1,654)	$ (1,290)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2010:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
	($ in millions)			
Financial Assets (Liabilities):				
Cash equivalents	$ 102	$ —	$ —	$ 102
Investments	29	—	—	29
Other long-term assets	52	—	—	52
Long-term debt	—	—	(1,371)	(1,371)
Other long-term liabilities	(52)	—	—	(52)
Derivatives:				
Commodity assets	—	1,364	105	1,469
Commodity liabilities	—	(59)	(2,059)	(2,118)
Interest rate liabilities	—	—	(69)	(69)
Foreign currency assets	—	—	(43)	(43)
Total derivatives	—	1,305	(2,066)	(761)
Total	$ 131	$ 1,305	$ (3,437)	$ (2,001)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

A summary of the changes in Chesapeake's assets (liabilities) classified as Level 3 measurements during 2011 and 2010 is presented below.

	Derivatives			
	Commodity	Interest Rate	Foreign Currency	Debt
	($ in millions)			
Beginning Balance as of January 1, 2011	$ (1,954)	$ (69)	$ (43)	$ (1,371)
Total gains (losses) (realized/unrealized):				
Included in earnings or change in net assets[a]	113	23	—	—
Total purchases, issuances, sales and settlements:				
Sales	(1)	(8)	—	—
Settlements	188	—	—	—
Transfers in and out of Level 3[b]	—	54	43	1,371
Ending Balance as of December 31, 2011	$ (1,654)	$ —	$ —	$ —
Beginning Balance as of January 1, 2010	$ (666)	$ (132)	$ 43	$ (1,398)
Total gains (losses) (realized/unrealized):				
Included in earnings or change in net assets[a]	(1,114)	60	(63)	77
Included in other comprehensive income (loss)	(25)	—	(23)	—
Total purchases, issuances, sales and settlements:				
Issuances	—	—	—	(1,300)[c]
Sales	—	3	—	—
Settlements	(149)	—	—	1,250[c]
Ending Balance as of December 31, 2010	$ (1,954)	$ (69)	$ (43)	$ (1,371)

(a)

	Natural Gas and Oil Sales		Interest Expense	
	2011	2010	2011	2010
	($ in millions)			
Total gains (losses) included in earnings (or change in net assets) for the period	$ 113	$ (1,114)	$ 23	$ 74
Change in unrealized gains (losses) relating to assets still held at reporting date	$ (263)	$ (1,646)	$ —	$ 27

(b) The values related to interest rate and cross currency swaps were transferred from Level 3 to Level 2 as a result of our ability to begin using data readily available in the public market to corroborate our estimated fair values.

(c) Amount represents an increase or decrease in debt recorded at fair value as a result of new or terminated interest rate swaps.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term debt primarily using quoted market prices. Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	December 31, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Long-term debt	$ 10,598	$ 11,399	$ 12,631	$ 13,272

16. Asset Retirement Obligations

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

	Years Ended December 31,	
	2011	2010
	($ in millions)	
Asset retirement obligations, beginning of period	$ 301	$ 282
Additions	20	16
Revisions	(1)	—
Settlements and disposals	(16)	(12)
Accretion expense	19	15
Asset retirement obligations, end of period	$ 323	$ 301

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

17. Major Customers and Segment Information

There were no sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) for the years ended December 31, 2011 and 2010. For the year ended December 31, 2009, we had $571 million of sales to EDF Trading North America LLC which represented 10% of our total revenues before the effects of hedging.

In accordance with accounting guidance for disclosures about segments of an enterprise and related information, we have three reportable operating segments. Our exploration and production operating segment, natural gas and oil marketing, gathering and compression operating segment and oilfield services operating segment are managed separately because of the nature of their products and services. The exploration and production operating segment is responsible for finding and producing natural gas and oil. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of natural gas and oil primarily from Chesapeake-operated wells. The oilfield services operating segment is responsible for contract drilling, oilfield trucking, oilfield rental, pressure pumping and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties.

COO, a wholly owned subsidiary of Chesapeake Oilfield Services, L.L.C. (COS), is a diversified oilfield services company that we formed in October 2011 to own and operate our oilfield service assets. COO provides a wide range of well site services, primarily to Chesapeake and its working interest partners, including contract drilling, pressure pumping, tool rental, transportation and manufacturing of natural gas compressor packages and related production equipment. In connection with the reorganization of our oilfield services subsidiaries and operations, those subsidiaries were released from the guarantees and other credit support obligations that existed for the benefit of Chesapeake and its other subsidiaries, including Chesapeake's senior notes and contingent convertible senior notes, its corporate revolving bank credit facility and its multi-counterparty hedging facility. In addition, COO and its subsidiaries entered into agreements with Chesapeake pursuant to which they sublease rigs, provide certain oilfield services and obtain certain administrative services.

As a result of the formal reorganization of our oilfield services business in October 2011, we are recognizing our oilfield services business as a new reportable segment. Historically, our oilfield services business was presented as part of other operations. All prior year information has been restated to reflect the addition of our oilfield services business as a new reportable segment.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of natural gas and oil related to Chesapeake's ownership interests by the marketing operating segment are reflected as exploration and production revenues. Such amounts totaled $5.0 billion, $4.0 billion and $2.9 billion for 2011, 2010 and 2009, respectively. The following table presents selected financial information for Chesapeake's operating segments.

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)			
For the Year Ended December 31, 2011:						
Revenues	$ 6,024	$ 10,336	$ 1,258	$ —	$ (5,983)	$ 11,635
Intersegment revenues	—	(5,246)	(737)	—	5,983	—
Total revenues	$ 6,024	$ 5,090	$ 521	$ —	$ —	$ 11,635
Depreciation, depletion and amortization	1,759	55	172	37	(100)	1,923
(Gains) losses on sales and impairments of fixed assets	3	(398)	4	—	—	(391)
Interest expense	(42)	(15)	(48)	(195)	256	(44)
Earnings on investments	—	95	—	61	—	156
Losses on purchases or exchanges of debt	(176)	—	—	—	—	(176)
Other income	260	1	5	35	(278)	23
Income (Loss) Before Income Taxes	$ 2,561	$ 745	$ 72	$ (168)	$ (330)	$ 2,880
Total Assets	$ 35,403	$ 4,047	$ 1,571	$ 2,718	$ (1,904)	$ 41,835
Net Capital Expenditures	$ 5,119	$ 213	$ 542	$ 463	$ —	$ 6,337

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)			
For the Year Ended December 31, 2010:						
Revenues	$ 5,647	$ 7,655	$ 757	$ —	$ (4,693)	$ 9,366
Intersegment revenues	—	(4,176)	(517)	—	4,693	—
Total revenues	$ 5,647	$ 3,479	$ 240	$ —	$ —	$ 9,366
Depreciation, depletion and amortization	1,518	43	94	28	(69)	1,614
(Gains) losses on sales and impairments of fixed assets	(2)	(119)	(1)	4	2	(116)
Interest expense	(15)	(17)	(25)	(90)	128	(19)
Earnings on investments	—	193	—	34	—	227
Losses on purchases or exchanges of debt	(129)	—	—	—	—	(129)
Impairment of investments	—	—	—	(16)	—	(16)
Other income	134	2	—	8	(128)	16
Income (Loss) Before Income Taxes	$ 2,663	$ 584	$ 10	$ (102)	$ (271)	$ 2,884
Total Assets	$ 31,840	$ 3,436	$ 875	$ 2,044	$ (1,016)	$ 37,179
Net Capital Expenditures	$ 8,519	$ (2,012)	$ 272	$ 150	$ —	$ 6,929

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)			
For the Year Ended December 31, 2009:						
Revenues	$ 5,049	$ 5,681	$ 609	$ —	$ (3,637)	$ 7,702
Intersegment revenues	—	(3,218)	(419)	—	3,637	—
Total revenues	$ 5,049	$ 2,463	$ 190	$ —	$ —	$ 7,702
Depreciation, depletion and amortization	1,531	44	63	24	(47)	1,615
(Gains) losses on sales and impairments of fixed assets	13	128	27	—	—	168
Impairment of natural gas and oil properties	11,000	—	—	—	—	11,000
Interest expense	(110)	(1)	—	(82)	80	(113)
Losses on investments	—	—	—	(39)	—	(39)
Losses on purchases or exchanges of debt	(40)	—	—	—	—	(40)
Impairment of investments	—	—	—	(162)	—	(162)
Other income	77	1	1	12	(80)	11
Income (Loss) Before Income Taxes	$ (8,873)	$ 293	$ (43)	$ (301)	$ (364)	$ (9,288)
Total Assets	$ 24,038	$ 4,305	$ 679	$ 1,851	$ (959)	$ 29,914
Net Capital Expenditures	$ 4,258	$ 953	$ 301	$ 581	$ —	$ 6,093

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

18. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes and contingent convertible senior notes listed in Note 3 are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly owned subsidiaries on a senior unsecured basis. Our midstream and oilfield services subsidiaries, CMD and COS and their subsidiaries, are not guarantors and are subject to covenants in their respective revolving bank credit facility agreements referred to in Note 3 that restrict them from paying dividends or distributions or making loans to Chesapeake. COS and its subsidiaries were released as guarantors in October 2011 when they were formally reorganized and capitalized. All prior year information has been restated to reflect COS and its subsidiaries as non-guarantor subsidiaries. In addition, CHK Utica, Chesapeake Granite Wash Trust and certain de minimis subsidiaries are also non-guarantors.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2011
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 1	$ 350	$ —	$ 351
Other	1	2,664	418	(257)	2,826
Total Current Assets	1	2,665	768	(257)	3,177
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost, based on full cost accounting, net	—	29,284	2,017	(101)	31,200
Other property and equipment at cost, net	—	2,831	2,708	—	5,539
Total Property and Equipment, Net	—	32,115	4,725	(101)	36,739
LONG TERM ASSETS:					
Other assets	61	1,010	1,225	(377)	1,919
Investments in subsidiaries and intercompany advances	3,051	782	—	(3,833)	—
TOTAL ASSETS	$ 3,113	$ 36,572	$ 6,718	$ (4,568)	$ 41,835
CURRENT LIABILITIES:					
Current liabilities	$ 288	$ 6,509	$ 543	$ (258)	$ 7,082
Intercompany payable to (receivable) from parent	(14,274)	12,076	2,154	44	—
Total Current Liabilities	(13,986)	18,585	2,697	(214)	7,082
LONG-TERM LIABILITIES:					
Long-term debt, net	28	9,917	681	—	10,626
Deferred income tax liabilities	409	2,718	501	(144)	3,484
Other liabilities	38	2,286	735	(377)	2,682
Total Long-Term Liabilities	475	14,921	1,917	(521)	16,792
STOCKHOLDERS' EQUITY:					
Chesapeake stockholders' equity	16,624	3,051	782	(3,833)	16,624
Noncontrolling interests	—	15	1,322	—	1,337
Total Stockholders' Equity	16,624	3,066	2,104	(3,833)	17,961
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 3,113	$ 36,572	$ 6,718	$ (4,568)	$ 41,835

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2010
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 1	$ 101	$ —	$ 102
Other	7	3,050	143	(36)	3,164
Total Current Assets	7	3,051	244	(36)	3,266
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost, based on full cost accounting, net	—	27,867	4	(45)	27,826
Other property and equipment at cost, net	—	2,409	2,143	—	4,552
Total Property and Equipment, Net	—	30,276	2,147	(45)	32,378
LONG-TERM ASSETS:					
Other assets	166	661	708	—	1,535
Investments in subsidiaries and intercompany advance	1,244	527	—	(1,771)	—
TOTAL ASSETS	$ 1,417	$ 34,515	$ 3,099	$ (1,852)	$ 37,179
CURRENT LIABILITIES:					
Current liabilities	$ 302	$ 3,965	$ 259	$ (36)	$ 4,490
Intercompany payable to (receivable) from parent	(23,637)	21,535	2,017	85	—
Total Current Liabilities	(23,335)	25,500	2,276	49	4,490
LONG-TERM LIABILITIES:					
Long-term debt, net	8,934	3,612	94	—	12,640
Deferred income tax liabilities	482	1,867	165	(130)	2,384
Other liabilities	72	2,292	37	—	2,401
Total Long-Term Liabilities	9,488	7,771	296	(130)	17,425
STOCKHOLDERS' EQUITY:					
Chesapeake stockholders' equity	15,264	1,244	527	(1,771)	15,264
Noncontrolling interests	—	—	—	—	—
Total Stockholders' Equity	15,264	1,244	527	(1,771)	15,264
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,417	$ 34,515	$ 3,099	$ (1,852)	$ 37,179

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2011
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil	$ —	$ 5,940	$ 84	$ —	$ 6,024
Marketing, gathering and compression	—	5,006	221	(137)	5,090
Oilfield services	—	—	1,252	(731)	521
Total Revenues	—	10,946	1,557	(868)	11,635
OPERATING EXPENSES:					
Natural gas and oil production	—	1,073	—	—	1,073
Production taxes	—	190	2	—	192
Marketing, gathering and compression	—	4,922	128	(83)	4,967
Oilfield services	—	1	949	(548)	402
General and administrative	—	478	70	—	548
Natural gas and oil depreciation, depletion and amortization	—	1,625	7	—	1,632
Depreciation and amortization of other assets	—	165	227	(101)	291
(Gains) losses on sales and impairments of fixed assets	—	2	(393)	—	(391)
Total Operating Expenses	—	8,456	990	(732)	8,714
INCOME FROM OPERATIONS	—	2,490	567	(136)	2,921
OTHER INCOME (EXPENSE):					
Interest expense	(640)	(12)	(50)	658	(44)
Earnings on investments	—	60	96	—	156
Losses on purchases or exchanges of debt	(176)	—	—	—	(176)
Other income	646	30	23	(676)	23
Equity in net earnings of subsidiary	1,846	295	—	(2,141)	—
Total Other Income (Expense)	1,676	373	69	(2,159)	(41)
INCOME BEFORE INCOME TAXES	1,676	2,863	636	(2,295)	2,880
INCOME TAX EXPENSE (BENEFIT)	(66)	1,002	248	(61)	1,123
NET INCOME	1,742	1,861	388	(2,234)	1,757
Net income attributable to noncontrolling interests	—	(15)	—	—	(15)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	$ 1,742	$ 1,846	$ 388	$ (2,234)	$ 1,742

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2010
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil	$ —	$ 5,647	$ —	$ —	$ 5,647
Marketing, gathering and compression	—	3,368	248	(137)	3,479
Oilfield services	—	—	758	(518)	240
Total Revenues	—	9,015	1,006	(655)	9,366
OPERATING EXPENSES:					
Natural gas and oil production	—	893	—	—	893
Production taxes	—	157	—	—	157
Marketing, gathering and compression	—	3,293	125	(66)	3,352
Oilfield services	—	—	608	(400)	208
General and administrative	2	399	52	—	453
Natural gas and oil depreciation, depletion and amortization	—	1,394	—	—	1,394
Depreciation and amortization of other assets	—	147	142	(69)	220
(Gains) losses on sales and impairments of fixed assets	—	1	(117)	—	(116)
Total Operating Expenses	2	6,284	810	(535)	6,561
INCOME (LOSS) FROM OPERATIONS	(2)	2,731	196	(120)	2,805
OTHER INCOME (EXPENSE):					
Interest expense	(637)	(75)	(25)	718	(19)
Earnings on investments	—	34	193	—	227
Losses on purchases or exchanges of debt	(129)	—	—	—	(129)
Impairment of investments	—	(16)	—	—	(16)
Other income	718	11	5	(718)	16
Equity in net earnings of subsidiary	1,805	153	—	(1,958)	—
Total Other Income	1,757	107	173	(1,958)	79
INCOME BEFORE INCOME TAXES	1,755	2,838	369	(2,078)	2,884
INCOME TAX EXPENSE (BENEFIT)	(19)	1,033	142	(46)	1,110
NET INCOME	$ 1,774	$ 1,805	$ 227	$ (2,032)	$ 1,774

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2009
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil	$ —	$ 5,049	$ —	$ —	$ 5,049
Marketing, gathering and compression	—	2,181	510	(228)	2,463
Oilfield services	—	1	605	(416)	190
Total Revenues	—	7,231	1,115	(644)	7,702
OPERATING EXPENSES:					
Natural gas and oil production	—	877	(1)	—	876
Production taxes	—	107	—	—	107
Marketing, gathering and compression	—	2,125	201	(10)	2,316
Oilfield services	—	1	527	(346)	182
General and administrative	—	286	63	—	349
Natural gas and oil depreciation, depletion and amortization	—	1,371	—	—	1,371
Depreciation and amortization of other assets	—	135	156	(47)	244
(Gains) losses on sales and impairments of fixed assets	—	13	155	—	168
Impairment of natural gas and oil properties	—	11,000	—	—	11,000
Restructuring	—	34	—	—	34
Total Operating Expenses	—	15,949	1,101	(403)	16,647
INCOME (LOSS) FROM OPERATIONS	—	(8,718)	14	(241)	(8,945)
OTHER INCOME (EXPENSE):					
Interest expense	(652)	(145)	(1)	685	(113)
Losses on investments	—	(39)	—	—	(39)
Losses on purchases or exchanges of debt	(40)	—	—	—	(40)
Impairment of investments	—	(162)	—	—	(162)
Other income (expense)	685	89	(78)	(685)	11
Equity in net losses of subsidiary	(5,826)	(217)	—	6,043	—
Total Other Income (Expense)	(5,833)	(474)	(79)	6,043	(343)
LOSS BEFORE INCOME TAXES	(5,833)	(9,192)	(65)	5,802	(9,288)
INCOME TAX BENEFIT	(3)	(3,366)	(24)	(90)	(3,483)
NET LOSS	(5,830)	(5,826)	(41)	5,892	(5,805)
Net income attributable to noncontrolling interests	—	—	(25)	—	(25)
NET LOSS ATTRIBUTABLE TO CHESAPEAKE	$ (5,830)	$ (5,826)	$ (66)	$ 5,892	$ (5,830)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2011
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 6,371	$ 337	$ (805)	$ 5,903
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(10,420)	(2,021)	—	(12,441)
Proceeds from divestitures of proved and unproved properties	—	7,651	—	—	7,651
Additions to other property and equipment	—	(586)	(1,477)	54	(2,009)
Other investing activities	—	(684)	637	1,034	987
Cash used in investing activities	—	(4,039)	(2,861)	1,088	(5,812)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	14,041	1,468	—	15,509
Payments on credit facilities borrowings	—	(15,934)	(1,532)	—	(17,466)
Proceeds from issuance of senior notes, net of offering costs	977	—	637	—	1,614
Cash paid to purchase debt	(2,015)	—	—	—	(2,015)
Proceeds from sales of noncontrolling interests	—	—	1,348	—	1,348
Other financing activities	(494)	1,169	689	(196)	1,168
Intercompany advances, net	1,532	(1,608)	163	(87)	—
Cash provided by (used in) financing activities	—	(2,332)	2,773	(283)	158
Net increase (decrease) in cash and cash equivalents	—	—	249	—	249
Cash and cash equivalents, beginning of period	—	1	101	—	102
Cash and cash equivalents, end of period	$ —	$ 1	$ 350	$ —	$ 351

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2010
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 4,865	$ 522	$ (270)	$ 5,117
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(12,187)	—	—	(12,187)
Proceeds from divestitures of proved and unproved properties	—	4,292	—	—	4,292
Additions to other property and equipment	—	(274)	(1,059)	7	(1,326)
Other investing activities	—	52	666	—	718
Cash used in investing activities	—	(8,117)	(393)	7	(8,503)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	14,384	733	—	15,117
Payments on credit facilities borrowings	—	(12,664)	(639)	—	(13,303)
Proceeds from issuance of senior notes, net of offering costs	1,967	—	—	—	1,967
Proceeds from issuance of preferred stock, net of offering costs	2,562	—	—	—	2,562
Cash paid to purchase debt	(3,434)	—	—	—	(3,434)
Other financing activities	(339)	613	(124)	122	272
Intercompany advances, net	(756)	627	(12)	141	—
Cash provided by (used in) financing activities	—	2,960	(42)	263	3,181
Net increase (decrease) in cash and cash equivalents	—	(292)	87	—	(205)
Cash and cash equivalents, beginning of period	—	293	14	—	307
Cash and cash equivalents, end of period	$ —	$ 1	$ 101	$ —	$ 102

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2009
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 4,440	$ (84)	$ —	$ 4,356
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(5,840)	—	—	(5,840)
Proceeds from divestitures of proved and unproved properties	—	1,926	—	—	1,926
Additions to other property and equipment	—	(578)	(1,105)	—	(1,683)
Other investing activities	—	73	62	—	135
Cash used in investing activities	—	(4,419)	(1,043)	—	(5,462)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	6,933	828	—	7,761
Payments on credit facilities borrowings	—	(8,514)	(1,244)	—	(9,758)
Proceeds from issuance of senior notes, net of offering costs	1,346	—	—	—	1,346
Proceeds from sale of noncontrolling interest	—	—	588	—	588
Other financing activities	(276)	77	187	(261)	(273)
Intercompany advances, net	(1,070)	27	782	261	—
Cash provided by (used in) financing activities	—	(1,477)	1,141	—	(336)
Net increase (decrease) in cash and cash equivalents	—	(1,456)	14	—	(1,442)
Cash and cash equivalents, beginning of period	—	1,749	—	—	1,749
Cash and cash equivalents, end of period	$ —	$ 293	$ 14	$ —	$ 307

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

19. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2011 and 2010 are as follows ($ in millions except per share data):

	Quarters Ended			
	March 31, 2011	June 30, 2011	September 30, 2011	December 31, 2011
Total revenues	$ 1,612	$ 3,318	$ 3,977	$ 2,728
Gross profit[(a)]	$ (284)	$ 985	$ 1,483	$ 737
Net income (loss) attributable to Chesapeake	$ (162)	$ 510	$ 922	$ 472
Net income (loss) available to common stockholders	$ (205)	$ 467	$ 879	$ 429
Net earnings (loss) per common share:				
Basic	$ (0.32)	$ 0.74	$ 1.38	$ 0.67
Diluted	$ (0.32)	$ 0.68	$ 1.23	$ 0.63

	Quarters Ended			
	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
Total revenues	$ 2,798	$ 2,012	$ 2,581	$ 1,975
Gross profit[(a)]	$ 1,212	$ 447	$ 817	$ 329
Net income attributable to Chesapeake	$ 738	$ 255	$ 558	$ 223
Net income available to common stockholders	$ 732	$ 235	$ 515	$ 181
Net earnings per common share:				
Basic	$ 1.16	$ 0.37	$ 0.81	$ 0.29
Diluted	$ 1.14	$ 0.37	$ 0.75	$ 0.28

(a) Total revenue less operating costs.

20. 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 December 2011, the FASB issued guidance on disclosure of information about offsetting and related arrangements to enable users of a company's financial statements to understand the effect of those arrangements on its financial position. The standard is effective for annual reporting periods beginning on or after January 1, 2013. This guidance will not have an impact on our financial position or results of operations.

In September 2011, the FASB issued guidance related to the annual goodwill impairment test. The guidance provides entities with the option of performing a qualitative assessment to determine whether the two-step goodwill impairment test is necessary. The revised standard is effective for goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We do not expect this guidance to have a material effect on our financial condition or results of operations as it is a change in application of the goodwill impairment test only.

In June 2011, the FASB issued guidance on comprehensive income, which provides two options for presenting items of net income, comprehensive income and total comprehensive income, by either creating one continuous statement of comprehensive income or two separate consecutive statements. We adopted this guidance in 2011. Adoption had no impact on our financial position or results of operations. In December 2011, the FASB deferred the effective date of certain presentation requirements for items reclassified out of accumulated other comprehensive income. This guidance will not have an impact on our financial position or results of operations.

In May 2011, the FASB issued guidance which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value under GAAP and International Financial Reporting Standards (IFRS). This new guidance changes some fair value measurement principles and disclosure requirements. We will have additional disclosures around our Level 3 financial instruments that are reported at fair value, and we will categorize the level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. This guidance is effective January 1, 2012. The guidance will not have an impact on our financial position or results of operations.

In 2010, the FASB issued guidance requiring additional disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method effective beginning on January 1, 2011. We adopted this guidance in 2011. Adoption had no impact on our financial position or results of operations. See Note 15 for discussion regarding fair value measurements.

21. Subsequent Events

Senior Notes Issuance

On February 16, 2012, we issued $1.3 billion of 6.775% Senior Notes due 2019 in a registered public offering. The senior notes were priced at 98.75% of par to yield 7%. We used the net proceeds of $1.261 billion from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility.

Schedule II

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

		Additions			
Description	**Balance at Beginning of Period**	**Charged To Expense**	**Charged To Other Accounts**	**Deductions**	**Balance At End of Period**
December 31, 2011:					
Allowance for doubtful accounts	$ 18	$ 1	$ —	$ —	$ 19
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —
December 31, 2010:					
Allowance for doubtful accounts	$ 24	$ —	$ —	$ (6)	$ 18
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —
December 31, 2009:					
Allowance for doubtful accounts	$ 12	$ 12	$ —	$ —	$ 24
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —

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

Not applicable.

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

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of December 31, 2011, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake's disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of December 31, 2011, to ensure that information required to be disclosed by Chesapeake is accumulated and communicated to Chesapeake management, including Chesapeake's Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls

No changes in the Company's internal control over financial reporting occurred during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

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

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

Not applicable.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2012.

ITEM 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2012.

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

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2012.

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

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2012.

ITEM 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2012.

PART IV

ITEM 15. ***Exhibits and Financial Statement Schedules***

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

1. *Financial Statements*. Chesapeake's consolidated financial statements are included in Item 8 of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules*. Schedule II is included in Item 8 of this report with our consolidated financial statements. No other financial statement schedules are applicable or required.
3. *Exhibits*. The following exhibits are filed herewith pursuant to the requirements of Item 601 of Regulation S-K:

		Incorporated by Reference					
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**	**Furnished Herewith**
3.1.1	Chesapeake's Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	08/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	05/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	08/09/2010		
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
4.1*	Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.5% Senior Notes due 2017.	8-K	001-13726	4.1	08/16/2005		
4.2*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% Senior Notes due 2020.	8-K	001-13726	4.1.1	11/15/2005		
4.3*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.75% Contingent Convertible Senior Notes due 2035.	8-K	001-13726	4.1.2	11/15/2005		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.4*	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.625% Senior Notes due 2013.	8-K	001-13726	4.1	06/30/2006		
4.5*	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% Senior Notes due 2017.	8-K	001-13726	4.1	12/06/2006		
4.6*	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.5% Contingent Convertible Senior Notes due 2037.	8-K	001-13726	4.1	05/15/2007		
4.7*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.25% Senior Notes due 2018.	8-K	001-13726	4.1	05/29/2008		
4.8*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.25% Contingent Convertible Senior Notes due 2038.	8-K	001-13726	4.2	05/29/2008		
4.9*	Indenture dated as of February 2, 2009 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 9.5% Senior Notes due 2015.	8-K	001-13726	4.1	02/03/2009		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.9.1*	First Supplemental Indenture dated as of February 10, 2009 to Indenture dated as of February 2, 2009, with respect to additional 9.5% Senior Notes due 2015.	8-K	001-13726	4.2	02/17/2009		
4.10*	Indenture dated as of August 2, 2010 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee.	S-3	333-168509	4.1	08/03/2010		
4.10.1*	First Supplemental Indenture dated as of August 17, 2010 to Indenture dated as of August 2, 2010 with respect to 6.875% Senior Notes due 2018.	8-A	001-13726	4.2	9/24/2010		
4.10.2*	Second Supplemental Indenture, dated as of August 17, 2010 to Indenture dated as of August 2, 2010 with respect to 6.625% Senior Notes due 2020.	8-A	001-13726	4.3	9/24/2010		
4.10.3*	Fifth Supplemental Indenture dated February 11, 2011 to Indenture dated as of August 2, 2010 with respect to 6.125% Senior Notes due 2021.	8-A	001-13726	4.2	2/22/2011		
4.10.4*	Ninth Supplemental Indenture dated February 16, 2012 to Indenture dated as of August 2, 2010, with respect to 6.775% Senior Notes due 2019.	8-A	001-13726	4.2	2/24/2012		
4.11*	Eighth Amended and Restated Credit Agreement, dated as of December 2, 2010, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, The Royal Bank of Scotland plc and BNP Paribas, as Co-Syndication Agent, Credit Agricole Corporate and Investment Bank, as Documentation Agent, and the several lenders from time to time parties thereto.	8-K	001-13726	4.1	12/8/2010		
4.11.1	First Amendment to Eighth Amended and Restated Credit Agreement, dated as of September 19, 2011, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, the other agents named therein and the several lenders parties thereto.	10-Q	001-13726	4.12.1	11/9/2011		

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.11.2	Second Amendment to Eighth Amended and Restated Credit Agreement, dated as of October 12, 2011, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, the other agents named therein and the several lenders parties thereto.	10-Q	001-13726	4.12.2	11/9/2011		
10.1.1†	Chesapeake's 2003 Stock Incentive Plan, as amended.	10-Q	001-13726	10.1.1	11/09/2009		
10.1.2†	Chesapeake's 1992 Nonstatutory Stock Option Plan, as amended.	10-Q	001-13726	10.1.2	02/14/1997		
10.1.3†	Chesapeake's 1994 Stock Option Plan, as amended.	10-Q	001-13726	10.1.3	11/07/2006		
10.1.4†	Chesapeake's 1996 Stock Option Plan, as amended.	10-Q	001-13726	10.1.4	11/07/2006		
10.1.5†	Chesapeake's 1999 Stock Option Plan, as amended.	10-Q	001-13726	10.1.5	08/11/2008		
10.1.6†	Chesapeake's 2000 Employee Stock Option Plan, as amended.	10-Q	001-13726	10.1.6	08/11/2008		
10.1.7†	Chesapeake's 2001 Stock Option Plan, as amended.	10-Q	001-13726	10.1.8	08/11/2008		
10.1.8†	Chesapeake's 2001 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.10	08/11/2008		
10.1.9†	Chesapeake's 2002 Stock Option Plan, as amended.	10-Q	001-13726	10.1.11	08/11/2008		
10.1.10†	Chesapeake's 2002 Non-Employee Director Stock Option Plan.	10-Q	001-13726	10.1.12	08/11/2008		
10.1.11†	Chesapeake's 2002 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.13	08/11/2008		
10.1.12†	Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, as amended.	10-K	001-13726	10.1.14	02/29/2008		
10.1.13†	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan.	10-K	001-13726	10.1.13	03/1/2011		
10.1.14†	Chesapeake's Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1.14	06/16/2011		
10.1.14.1†	Form of Restricted Stock Award Agreement for the Long Term Incentive Plan.	10-K	001-13726	10.1.14.1	03/1/2011		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.1.14.2†	Form of Non-Employee Director Restricted Stock Award Agreement for the Long Term Incentive Plan.	8-K	001-13726	10.1.18.3	06/16/2005		
10.1.14.3†	Form of Performance Share Unit Award Agreement.	8-K	001-13726	10.1.17	12/21/2011		
10.1.15†	Founder Well Participation Program.	DEF - 14A	001-13726	B	04/29/2005		
10.1.16†	Chesapeake Energy Corporation 2012 Annual Incentive Plan.	8-K	001-13726	10.1.16	12/21/2011		
10.2.1†	Third Amended and Restated Employment Agreement dated as of March 1, 2009 between Aubrey K. McClendon and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.1	05/11/2009		
10.2.2†	Amended and Restated Employment Agreement dated as of September 30, 2009 between Steven C. Dixon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.3	10/01/2009		
10.2.3†	Amended and Restated Employment Agreement dated as of September 30, 2009 between Douglas J. Jacobson and Chesapeake Energy Corporation.	8-K	001-13726	10.2.5	10/01/2009		
10.2.4†	Employment Agreement dated as of November 5, 2010 between Domenic J. Dell'Osso, Jr. and Chesapeake Energy Corporation.	10-Q	001-13726	10.2	11/09/2010		
10.2.5†	Employment Agreement dated as of September 30, 2009 between Martha A. Burger and Chesapeake Energy Corporation.	10-K	001-13726	10.2.7	03/1/2011		
10.2.6†	Form of Employment Agreement between Senior Vice President and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.7	11/9/2009		
10.2.7†	Form of Amendment to Employment Agreement dated as of December 22, 2011 between Executive Vice President/Senior Vice President and Chesapeake Energy Corporation.					X	
10.3†	Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries.	10-K	001-13726	10.3	02/29/2008		
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X	
21	Subsidiaries of Chesapeake.					X	
23.1	Consent of PricewaterhouseCoopers, LLP.					X	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
23.2	Consent of Netherland, Sewell & Associates, Inc.					X	
23.3	Consent of Data & Consulting Services, Division of Schlumberger Technology Corporation.					X	
23.4	Consent of Lee Keeling and Associates, Inc.					X	
23.5	Consent of Ryder Scott Company, L.P.					X	
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
32.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
99.1	Report of Netherland, Sewell & Associates, Inc.					X	
99.2	Report of Data & Consulting Services, Division of Schlumberger Technology Corporation.					X	
99.3	Report of Lee Keeling and Associates, Inc.					X	
99.4	Report of Ryder Scott Company, L.P.					X	
101.INS#	XBRL Instance Document.					X	X
101.SCH#	XBRL Taxonomy Extension Schema Document.					X	X
101.CAL#	XBRL Taxonomy Extension Calculation Linkbase Document.					X	X
101.DEF#	XBRL Taxonomy Extension Definition Linkbase Document.					X	X
101.LAB#	XBRL Taxonomy Extension Labels Linkbase Document.					X	X
101.PRE#	XBRL Taxonomy Extension Presentation Linkbase Document.					X	X

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

† Management contract or compensatory plan or arrangement.

Signatures

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

Date: February 29, 2012

CHESAPEAKE ENERGY CORPORATION
By: /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon
Chairman of the Board and
Chief Executive Officer

POWER OF ATTORNEY

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

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

Signature	Capacity	Date
/s/ AUBREY K. MCCLENDON **Aubrey K. McClendon**	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	February 29, 2012
/s/ DOMENIC J. DELL'OSSO, JR. **Domenic J. Dell'Osso, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 29, 2012
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President – Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 29, 2012
/s/ RICHARD K. DAVIDSON **Richard K. Davidson**	Director	February 29, 2012
/s/ KATHLEEN EISBRENNER **Kathleen Eisbrenner**	Director	February 29, 2012
/s/ V. BURNS HARGIS **V. Burns Hargis**	Director	February 29, 2012
/s/ FRANK KEATING **Frank Keating**	Director	February 29, 2012
/s/ CHARLES T. MAXWELL **Charles T. Maxwell**	Director	February 29, 2012
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	February 29, 2012
/s/ DON NICKLES **Don Nickles**	Director	February 29, 2012
/s/ LOUIS A. SIMPSON **Louis A. Simpson**	Director	February 29, 2012

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INDEX TO EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1.1	Chesapeake's Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	08/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	05/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	08/09/2010		
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
4.1*	Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.5% Senior Notes due 2017.	8-K	001-13726	4.1	08/16/2005		
4.2*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% Senior Notes due 2020.	8-K	001-13726	4.1.1	11/15/2005		
4.3*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.75% Contingent Convertible Senior Notes due 2035.	8-K	001-13726	4.1.2	11/15/2005		
4.4*	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.625% Senior Notes due 2013.	8-K	001-13726	4.1	06/30/2006		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.5*	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% Senior Notes due 2017.	8-K	001-13726	4.1	12/06/2006		
4.6*	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.5% Contingent Convertible Senior Notes due 2037.	8-K	001-13726	4.1	05/15/2007		
4.7*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.25% Senior Notes due 2018.	8-K	001-13726	4.1	05/29/2008		
4.8*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.25% Contingent Convertible Senior Notes due 2038.	8-K	001-13726	4.2	05/29/2008		
4.9*	Indenture dated as of February 2, 2009 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 9.5% Senior Notes due 2015.	8-K	001-13726	4.1	02/03/2009		
4.9.1*	First Supplemental Indenture dated as of February 10, 2009 to Indenture dated as of February 2, 2009, with respect to additional 9.5% Senior Notes due 2015.	8-K	001-13726	4.2	02/17/2009		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.10*	Indenture dated as of August 2 2010, among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee.	S-3	333-168509	4.1	08/03/2010		
4.10.1*	First Supplemental Indenture dated as of August 17, 2010 to Indenture dated as of August 2, 2010, with respect to 6.875% Senior Notes due 2018.	8-A	001-13726	4.2	9/24/2010		
4.10.2*	Second Supplemental Indenture dated as of August 17, 2010 to Indenture dated as of August 2, 2010, with respect to 6.625% Senior Notes due 2020.	8-A	001-13726	4.3	9/24/2010		
4.10.3*	Fifth Supplemental Indenture dated February 11, 2011 to Indenture dated as of August 2, 2010, with respect to 6.125% Senior Notes due 2021.	8-A	001-13726	4.2	2/22/2011		
4.10.4*	Ninth Supplemental Indenture dated February 16, 2012 to Indenture dated as of August 2, 2010, with respect to 6.775% Senior Notes due 2019.	8-A	001-13726	4.2	2/24/2012		
4.11*	Eighth Amended and Restated Credit Agreement, dated as of December 2, 2010, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, The Royal Bank of Scotland plc and BNP Paribas, as Co-Syndication Agent, Credit Agricole Corporate and Investment Bank, as Documentation Agent, and the several lenders from time to time parties thereto.	8-K	001-13726	4.1	12/8/2010		
4.11.1	First Amendment to Eighth Amended and Restated Credit Agreement, dated as of September 19, 2011, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, the other agents named therein and the several lenders parties thereto.	10-Q	001-13726	4.12.1	11/9/2011		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.11.2	Second Amendment to Eighth Amended and Restated Credit Agreement, dated as of October 12, 2011, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, the other agents named therein and the several lenders parties thereto.	10-Q	001-13726	4.12.2	11/9/2011		
10.1.1†	Chesapeake's 2003 Stock Incentive Plan, as amended.	10-Q	001-13726	10.1.1	11/09/2009		
10.1.2†	Chesapeake's 1992 Nonstatutory Stock Option Plan, as amended.	10-Q	001-13726	10.1.2	02/14/1997		
10.1.3†	Chesapeake's 1994 Stock Option Plan, as amended.	10-Q	001-13726	10.1.3	11/07/2006		
10.1.4†	Chesapeake's 1996 Stock Option Plan, as amended.	10-Q	001-13726	10.1.4	11/07/2006		
10.1.5†	Chesapeake's 1999 Stock Option Plan, as amended.	10-Q	001-13726	10.1.5	08/11/2008		
10.1.6†	Chesapeake's 2000 Employee Stock Option Plan, as amended.	10-Q	001-13726	10.1.6	08/11/2008		
10.1.7†	Chesapeake's 2001 Stock Option Plan, as amended.	10-Q	001-13726	10.1.8	08/11/2008		
10.1.8†	Chesapeake's 2001 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.10	08/11/2008		
10.1.9†	Chesapeake's 2002 Stock Option Plan, as amended.	10-Q	001-13726	10.1.11	08/11/2008		
10.1.10†	Chesapeake's 2002 Non-Employee Director Stock Option Plan.	10-Q	001-13726	10.1.12	08/11/2008		
10.1.11†	Chesapeake's 2002 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.13	08/11/2008		
10.1.12†	Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, as amended.	10-K	001-13726	10.1.14	02/29/2008		
10.1.13†	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan.	10-K	001-13726	10.1.13	03/1/2011		
10.1.14†	Chesapeake's Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1.14	06/16/2011		
10.1.14.1†	Form of Restricted Stock Award Agreement for the Long Term Incentive Plan.	10-K	001-13726	10.1.14.1	03/1/2011		
10.1.14.2†	Form of Non-Employee Director Restricted Stock Award Agreement for the Long Term Incentive Plan.	8-K	001-13726	10.1.18.3	06/16/2005		
10.1.14.3†	Form of Performance Share Unit Award Agreement.	8-K	001-13726	10.1.17	12/21/2011		

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.1.15†	Founder Well Participation Program.	DEF - 14A	001-13726	B	04/29/2005		
10.1.16†	Chesapeake Energy Corporation 2012 Annual Incentive Plan.	8-K	001-13726	10.1.16	12/21/2011		
10.2.1†	Third Amended and Restated Employment Agreement dated as of March 1, 2009 between Aubrey K. McClendon and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.1	05/11/2009		
10.2.2†	Amended and Restated Employment Agreement dated as of September 30, 2009 between Steven C. Dixon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.3	10/01/2009		
10.2.3†	Amended and Restated Employment Agreement dated as of September 30, 2009 between Douglas J. Jacobson and Chesapeake Energy Corporation.	8-K	001-13726	10.2.5	10/01/2009		
10.2.4†	Employment Agreement dated as of November 5, 2010 between Domenic J. Dell'Osso, Jr. and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.	11/09/2010		
10.2.5†	Employment Agreement dated as of September 30, 2009 between Martha A. Burger and Chesapeake Energy Corporation.	10-K	001-13726	10.2.7	03/1/2011		
10.2.6†	Form of Employment Agreement between Senior Vice President and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.7	11/9/2009		
10.2.7†	Form of Amendment to Employment Agreement dated as of December 22, 2011 between Executive Vice President/Senior Vice President and Chesapeake Energy Corporation.					X	
10.3†	Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries.	10-K	001-13726	10.3	02/29/2008		
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X	
21	Subsidiaries of Chesapeake.					X	
23.1	Consent of PricewaterhouseCoopers, LLP.					X	
23.2	Consent of Netherland, Sewell & Associates, Inc.					X	
23.3	Consent of Data & Consulting Services, Division of Schlumberger Technology Corporation.					X	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
23.4	Consent of Lee Keeling and Associates, Inc.					X	
23.5	Consent of Ryder Scott Company, L.P.					X	
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
32.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
99.1	Report of Netherland, Sewell & Associates, Inc.					X	
99.2	Report of Data & Consulting Services, Division of Schlumberger Technology Corporation.					X	
99.3	Report of Lee Keeling and Associates, Inc.					X	
99.4	Report of Ryder Scott Company, L.P.					X	
101.INS#	XBRL Instance Document.					X	X
101.SCH#	XBRL Taxonomy Extension Schema Document.					X	X
101.CAL#	XBRL Taxonomy Extension Calculation Linkbase Document.					X	X
101.DEF#	XBRL Taxonomy Extension Definition Linkbase Document.					X	X
101.LAB#	XBRL Taxonomy Extension Labels Linkbase Document.					X	X
101.PRE#	XBRL Taxonomy Extension Presentation Linkbase Document.					X	X

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

† Management contract or compensatory plan or arrangement.

Exhibit 10.2.7

FORM OF AMENDMENT TO EMPLOYMENT AGREEMENT

This Amendment to Employment Agreement (the "Amendment") is effective December 22, 2011 (the "Effective Date"), by and between Chesapeake Energy Corporation, an Oklahoma corporation (the "Company"), and [Executive Name], an individual (the "Executive"). The Company and the Executive are referred to collectively in this Amendment as the "Parties."

WHEREAS, the Parties have entered into an employment agreement (the "Employment Agreement"); and

WHEREAS, the Parties desire to amend the Employment Agreement.

NOW, THEREFORE, in consideration of the promises and mutual agreements herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

1. All capitalized terms used in this Amendment and not otherwise defined shall have the same meaning in this Amendment as in the Employment Agreement.

2. The Employment Agreement is amended to delete Subparagraph 4.4.2 in its entirety.

3. Except as otherwise amended by this Amendment, the remaining terms of the Employment Agreement remain in full force and effect.

IN WITNESS WHEREOF, the Parties have executed this Amendment to Employment Agreement as of the Effective Date.

Company: Chesapeake Energy Corporation

By: _____

Aubrey K. McClendon
Chief Executive Officer

Executive: _____

[Executive Name]

EXHIBIT 12

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

RATIOS OF EARNINGS TO FIXED CHARGES AND COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS

	Year Ended December 31,					
	2006	2007	2008	2009	2010	2011
	($ in millions)					
EARNINGS:						
Income (loss) before income taxes and cumulative effect of accounting change	$3,241	$2,347	$ 991	$(9,288)	$2,884	$2,880
Interest expense[a]	318	375	225	237	122	94
(Gain)/loss on investment in equity investees in excess of distributed earnings	(3)	21	40	39	(232)	(154)
Amortization of capitalized interest	19	40	74	150	212	297
Loan cost amortization	13	16	19	26	25	28
Earnings	$3,588	$2,799	$1,349	$(8,836)	$3,011	$3,145
FIXED CHARGES:						
Interest Expense	$ 318	$ 375	$ 225	$ 237	$ 122	$ 94
Capitalized interest	179	311	586	627	711	727
Loan cost amortization	13	16	19	26	25	28
Fixed Charges	$ 510	$ 702	$ 830	$ 890	$ 858	$ 849
PREFERRED STOCK DIVIDENDS:						
Preferred dividend requirements	$ 89	$ 94	$ 33	$ 23	$ 111	$ 172
Ratio of income before provision for taxes to net income[b]	1.63	1.62	1.64	1.59	1.63	1.65
Preferred Dividends	$ 145	$ 152	$ 54	$ 37	$ 181	$ 284
COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS	$ 655	$ 854	$ 884	$ 927	$1,039	$1,131
RATIO OF EARNINGS TO FIXED CHARGES	7.0	4.0	1.6	(9.9)	3.5	3.7
INSUFFICIENT COVERAGE	$ —	$ —	$ —	$ 9,726	$ —	$ —
RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS	5.5	3.3	1.5	(9.5)	2.9	2.8
INSUFFICIENT COVERAGE	$ —	$ —	$ —	$ 9,763	$ —	$ —

(a) Excludes the effect of unrealized gains or losses on interest rate derivatives and includes amortization of bond discount.

(b) Amounts of income before provision for taxes and of net income exclude the cumulative effect of accounting change.

Exhibit 21

SUBSIDIARIES
OF
CHESAPEAKE ENERGY CORPORATION*
Oklahoma Corporation

Corporations	**State of Organization**
Chesapeake Energy Louisiana Corporation	Oklahoma
Chesapeake Energy Marketing, Inc.	Oklahoma
Chesapeake E&P Holding Corporation	Oklahoma
Chesapeake Operating, Inc.	Oklahoma
CHK Holdings Corporation	Oklahoma
Limited Liability Companies	**State of Formation**
Chesapeake Appalachia, L.L.C.	Oklahoma
Chesapeake Exploration, L.L.C.	Oklahoma
Chesapeake Land Development Company, L.L.C.	Oklahoma
Chesapeake Midstream Operating, L.L.C.	Oklahoma
Chesapeake Oilfield Services, L.L.C.	Oklahoma
Chesapeake Oilfield Operating, L.L.C.	Oklahoma
CHK Utica, L.L.C.	Delaware
Nomac Drilling, L.L.C.	Oklahoma
Partnerships	
Chesapeake Louisiana, L.P.	Oklahoma
Chesapeake Midstream Development, L.P.	Delaware

* In accordance with Regulation S-K Item 601(b)(21), the names of particular subsidiaries that, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary (as that term is defined in Rule 1-02(w) of Regulation S-X) as of the end of the year covered by this report have been omitted.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-88196, 333-07255, 333-27525, 333-30324, 333-30478, 333-52668, 333-67734, 333-67740, 333-109162, 333-118312, 333-126191, 333-135949, 333-143990, 333-151762, 333-157504, 333-160350, 333-171468 and 333-178067) and Form S-3 (File No. 333-168509) of Chesapeake Energy Corporation of our report dated February 29, 2012 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/S/ PRICEWATERHOUSECOOPERS LLP

PRICEWATERHOUSECOOPERS LLP

Tulsa, Oklahoma
February 29, 2012

Exhibit 23.2

CONSENT OF NETHERLAND, SEWELL & ASSOCIATES, INC.

As independent oil and gas consultants, Netherland, Sewell & Associates, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-88196, 333-07255, 333-27525, 333-30324, 333-30478, 333-52668, 333-67734, 333-67740, 333-109162, 333-118312, 333-126191, 333-135949, 333-143990, 333-151762, 333-157504, 333-160350, 333-171468 and 333-178067) and Form S-3 (File No. 333-168509) of Chesapeake Energy Corporation of all references to our firm and information from our reserves report dated January 16, 2012 included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K for the year ended December 31, 2011 to be filed with the Securities and Exchange Commission on or about February 29, 2012, and our summary report attached as Exhibit 99.1 to such Annual Report on Form 10-K.

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699
By: /S/ C.H. (SCOTT) REES III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
February 29, 2012

Exhibit 23.3

CONSENT OF DATA & CONSULTING SERVICES
DIVISION OF SCHLUMBERGER TECHNOLOGY CORPORATION

As independent oil and gas consultants, Data & Consulting Services Division of Schlumberger Technology Corporation hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-88196, 333-07255, 333-27525, 333-30324, 333-30478, 333-52668, 333-67734, 333-67740, 333-109162, 333-118312, 333-126191, 333-135949, 333-143990, 333-151762, 333-157504, 333-160350, 333-171468 and 333-178067) and Form S-3 (File No. 333-168509) of Chesapeake Energy Corporation of all references to our firm and information from our reserves report dated 9 February 2012, entitled "Reserve and Economic Evaluation Of Proved Reserves Of Certain Chesapeake Energy Corporation Eastern Division Oil and Gas Interests as of 31 December 2011", included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K for the year ended December 31, 2011 to be filed with the Securities and Exchange Commission on or about February 29, 2012, and our summary report attached as Exhibit 99.2 to such Annual Report on Form 10-K.

DATA & CONSULTING SERVICES DIVISION OF SCHLUMBERGER TECHNOLOGY CORPORATION

By: /S/ CHARLES M. BOYER II

Charles M. Boyer II, PG, CPG
Consulting Services Manager – NE Basin
Advisor – Unconventional Reservoirs

Pittsburgh, Pennsylvania
29 February 2012

Exhibit 23.4

CONSENT OF LEE KEELING AND ASSOCIATES, INC.

As independent oil and gas consultants, Lee Keeling and Associates, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-88196, 333-07255, 333-27525, 333-30324, 333-30478, 333-52668, 333-67734, 333-67740, 333-109162, 333-118312, 333-126191, 333-135949, 333-143990, 333-151762, 333-157504, 333-160350, 333-171468 and 333-178067) and Form S-3 (File No. 333-168509) of Chesapeake Energy Corporation of all references to our firm and information from our reserves report dated January 18, 2012, entitled "Estimated Reserves and Future Net Revenue Selected Interests Owned by Chesapeake Energy Corporation Constant Prices and Expenses", included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K for the year ended December 31, 2011 to be filed with the Securities and Exchange Commission on or about February 29, 2012, and our summary report attached as Exhibit 99.3 to such Annual Report on Form 10-K.

/S/ LEE KEELING AND ASSOCIATES, INC.

LEE KEELING AND ASSOCIATES, INC.

Tulsa, Oklahoma
February 29, 2012

Exhibit 23.5

CONSENT OF RYDER SCOTT COMPANY, L.P.

As independent oil and gas consultants, Ryder Scott Company, L.P. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-88196, 333-07255, 333-27525, 333-30324, 333-30478, 333-52668, 333-67734, 333-67740, 333-109162, 333-118312, 333-126191, 333-135949, 333-143990, 333-151762, 333-157504, 333-160350, 333-171468 and 333-178067) and Form S-3 (File No. 333-168509) of Chesapeake Energy Corporation of all references to our firm and information from our reserves report dated January 23, 2012, entitled "Chesapeake Energy Corporation Estimated Future Reserves and Income Attributable to Certain Leasehold and Royalty Interests SEC Parameters as of December 31, 2011", included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K for the year ended December 31, 2011 to be filed with the Securities and Exchange Commission on or about February 29, 2012, and our summary report attached as Exhibit 99.4 to such Annual Report on Form 10-K.

/S/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Registration No. F-1580

Houston, Texas
February 29, 2012

Exhibit 31.1

CERTIFICATION

I, Aubrey K. McClendon, certify that:

1. I have reviewed this annual report on Form 10-K of Chesapeake Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   - (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   - (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   - (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   - (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   - (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2012

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

Exhibit 31.2

CERTIFICATION

I, Domenic J. Dell'Osso, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Chesapeake Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   - (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   - (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   - (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   - (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   - (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2012

/s/ DOMENIC J. DELL'OSSO, JR.
Domenic J. Dell'Osso, Jr.
Executive Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO SECTION 906

OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Chesapeake Energy Corporation (the "Company") on Form 10-K for the period ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Aubrey K. McClendon, Chairman and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 29, 2012

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

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO SECTION 906

OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Chesapeake Energy Corporation (the "Company") on Form 10-K for the period ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 29, 2012

By: /s/ DOMENIC J. DELL'OSSO, JR.
Domenic J. Dell'Osso, Jr.
Executive Vice President and
Chief Financial Officer

Exhibit 99.1

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANIEL D. SIMMONS
EXECUTIVE VP
G. LANCE SHOOK

EXECUTIVE COMMITTEE
P. SCOTT FROST • DALLAS
J. CARTER HENSON JR. • HOUSTON
DAN PAUL SMITH • DALLAS
JOSEPH J. SPELLMAN • DALLAS
THOMAS J. TELLE IV • DALLAS

January 16, 2012

Mr. Gary L. Egger

Chesapeake Energy Corporation
6100 North Western Avenue
Oklahoma City, Oklahoma 73118

Dear Mr. Egger:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2011, to the Chesapeake Energy Corporation (Chesapeake) interest in certain oil and gas properties located in the Barnett and Haynesville districts of Louisiana and Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 42 percent of all proved reserves owned by Chesapeake. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Chesapeake's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Chesapeake interest in these properties, as of December 31, 2011, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	304.5	12,279.3	4,039,753.8	7,331,334.0	3,949,420.8
Proved Developed Non-Producing	40.7	1,179.3	390,882.3	574,347.6	308,190.9
Proved Undeveloped	26.9	2,973.8	3,334,843.5	3,100,190.8	129,306.7
Total Proved	372.1	16,432.5	7,765,480.0	11,005,873.0	4,386,918.0

Totals may not add because of rounding.

The oil reserves shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. No study was made to determine whether probable or possible reserves might be established for these properties. Estimates of proved undeveloped reserves have been included for certain locations that generate positive future net revenue but have negative present worth discounted at 10 percent based on the constant prices and costs discussed in subsequent paragraphs of this letter. The operated locations have been included based on Chesapeake's declared intent to drill these wells, as evidenced by their internal budget and reserves estimates. The nonoperated locations have been included as requested by Chesapeake. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

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1221 LAMAR STREET, SUITE 1200 • HOUSTON, TEXAS 77010-3072 • PH 713-654-4859 • FAX 713-654-4951
nsai@nsai-petro.com
netherlandsewell.com

Gross revenue shown in this report is Chesapeake's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Chesapeake's share of production taxes and ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2011. For oil and NGL volumes, the average Platts *Gas Daily* West Texas Intermediate Crude spot price of $95.97 per barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For gas volumes, the average Platts *Gas Daily* Henry Hub spot price of $4.118 per MMBTU is adjusted by lease for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $92.21 per barrel of oil, $34.02 per barrel of NGL, and $2.802 per MCF of gas.

Operating costs used in this report are based on operating expense records of Chesapeake. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and $220 per well per month, which is Chesapeake's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties; these overhead expenses are not included in the determination of the economic limits for the properties. As requested, ad valorem taxes are included in the operating costs for the nonoperated properties. Operating costs are held constant throughout the lives of the properties.

Capital costs used in this report were provided by Chesapeake and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of Chesapeake's future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Chesapeake's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are held constant to the date of expenditure.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the Chesapeake interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Chesapeake receiving its net revenue interest share of estimated future gross gas production. Some of these properties are subject to volumetric production payment (VPP) transactions completed by Chesapeake during 2008 and 2010. Our estimates of reserves and future revenue do not include adjustments for any of these VPP transactions; however, it is our understanding that Chesapeake has given effect to those transactions by reducing their reserves at the corporate level.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental

regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Chesapeake, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699
By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Randolph K. Green
Randolph K. Green, P.E. 72951
Vice President
Date Signed: January 16, 2012
RKG:ERH

By: /s/ William J. Knights
William J. Knights, P.G. 1532
Vice President
Date Signed: January 16, 2012

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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(7) *Development costs*. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate*. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified 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 oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data 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.

(iii) 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.

(iv) 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.

(v) 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.

(23) *Proved properties.* Properties with proved reserves.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

(i) 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.

(ii) Undrilled locations can be classified as having 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.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.2

Reserve And Economic Evaluation Of Proved Reserves Of Certain Chesapeake Energy Corporation Eastern Division Oil And Gas Interests As Of 31 December 2011

Executive Summary

Prepared For

Chesapeake Energy Corporation
Oklahoma City, Oklahoma

Prepared By

Data & Consulting Services
Division of Schlumberger Technology Corporation
Pittsburgh, Pennsylvania

February 2012

Data & Consulting Services
Division of Schlumberger Technology Corporation

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Schlumberger

9 February 2012

Chesapeake Energy Corporation
6100 N. Western Avenue
Oklahoma City, OK 73118
Building Seven

Dear Gentlemen:

At the request of Chesapeake Energy Corporation (Chesapeake), through their letter of engagement, Data & Consulting Services (DCS) Division of Schlumberger Technology Corporation has evaluated the proved reserves of certain Chesapeake oil and gas interests located in their Eastern Division United States (U.S.) properties as of 31 December 2011. The evaluated properties are located in Kentucky, New York, Pennsylvania, and West Virginia. This report was completed as of the date of this letter and has been prepared using constant prices and costs and conforms to our understanding of the U.S. Securities and Exchange Commission (SEC) guidelines and applicable financial accounting rules. All prices, costs, and cash flow estimates are expressed in U.S. dollars (US $). It is our understanding that the properties evaluated by DCS comprise approximately 7.2 percent (7.2%) of Chesapeake's total proved reserves. We prepared this report for Chesapeake's use in filing with the SEC. We believe that the assumptions, data, methods, and procedures used in preparing this report are appropriate for the purpose of this report and that we have used all methods and procedures that we consider necessary and appropriate under the circumstances to prepare this report. The Lead Evaluator for this evaluation was Charles M. Boyer II, PG, CPG, and his qualifications, independence, objectivity, and confidentiality meet the requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The results of the Proved reserve evaluation are summarized in **Table 1** and **Table 2**. The values contained in this report do not include existing Chesapeake financial instruments or hedges. **Fig. 1** illustrates the net gas equivalent reserves distribution by reserve category for the properties evaluated. **Attachment 1** contains the summary level cash flows by reserve category for this evaluation.

Table 1

Estimated Net Reserves And Income
Certain Eastern Division Oil And Gas Interests
Chesapeake Energy Corporation
As Of 31 December 2011
Proved Developed And Undeveloped Reserves

	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Remaining Net Reserves			
Oil – Mbbls	1,107.14	587.15	1,694.29
NGL—Mbbls	8,675.85	6,106.40	14,782.26
Gas – MMscf	1,084,843.50	159,891.91	1,244,735.38
Gas Equiv. – MMscfe	1,143,541.50	200,053.22	1,343,594.62
Income Data (M$)			
Future Net Revenue	4,782,724.23	971,404.68	5,754,129.31
Deductions			
Operating Expense	1,406,418.25	140,191.36	1,546,609.88
Production Taxes	285,922.48	82,700.38	368,622.88
Investment	134,314.44	238,887.58	373,202.03
Future Net Cashflow (FNC)	2,956,068.50	509,625.41	3,465,694.25
Discounted PV @ 10% (M$)	1,510,296.50	117,387.34	1,627,683.50

Table 2

Estimated Net Reserves And Income
Certain Eastern Division Oil And Gas Interests
Summarized By Reserve Category
Chesapeake Energy Corporation
As Of 31 December 2011

	Proved Producing Reserves	Proved Behind Pipe Reserves	Proved Non-producing Reserves	Proved Shut-In Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Remaining Net Reserves						
Oil – Mbbls	982.50	0.00	124.64	0.00	587.15	1,694.29
NGL—Mbbls	8,466.16	0.61	209.08	0.00	6,106.40	14,782.26
Gas – MMscf	1,054,696.12	4,227.52	25,919.96	0.00	159,891.91	1,244,735.38
Gas Equiv. – MMscfe	1,111,388.00	4,231.18	27,922.28	0.00	200,053.22	1,343,594.62
Income Data (M$)						
Future Net Revenue	4,643,175.86	16,564.95	122,983.54	0.01	971,404.68	5,754,129.31
Deductions						
Operating Expense	1,382,085.38	9,173.23	14,082.88	1,077.10	140,191.36	1,546,609.88
Production Taxes	284,228.19	1,160.44	533.86	0.00	82,700.38	368,622.88
Investment	124,948.82	3,742.07	943.90	4,679.62	238,887.58	373,202.03
Future Net Cashflow (FNC)	2,851,913.50	2,489.20	107,422.90	(5,756.72)	509,625.41	3,465,694.25
Discounted PV @ 10% (M$)	1,447,493.00	113.66	68,005.09	(5,315.48)	117,387.34	1,627,683.50

The values in the tables above may not add up arithmetically or exactly match the attached cash flows due to rounding procedures in the computer software program used to prepare the economic projections.

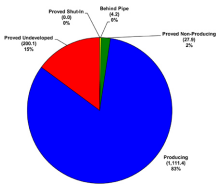

Fig. 1—Net gas equivalent reserves distribution by reserve category – (Bcfe).

RESERVES ESTIMATES

Standard geological and engineering methods generally accepted by the petroleum industry were used in the estimation of Chesapeake's reserves. Deterministic methods were used for all reserves included in this report. The appropriate combination of conventional decline curve analysis (DCA), production data analysis, volumetrics, and type curves were used to estimate the remaining reserves in the various producing areas. Volumetric calculations were based on data and maps provided by Chesapeake. Comparisons were made to similar properties for which more complete data were available for areas of new development.

Reserve estimates are strictly technical judgments. The accuracy of any reserve estimate is a function of the quality and quantity of data available and of the engineering and geological interpretations. The reserve estimates presented in this report are believed reasonable; however, they are estimates only and should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify their revision. A portion of these reserves are for undeveloped locations and producing or non-producing wells that lack sufficient production history to utilize conventional performance-based reserve estimates. In these cases, the reserves are based on volumetric estimates and recovery efficiencies along with analogies to similar producing areas. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. As additional production and pressure data becomes available, these estimates may be revised up or down. Actual future prices may vary significantly from the prices used in this evaluation; therefore, future hydrocarbon volumes recovered and the income received from these volumes may vary significantly from those estimated in this report. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

RESERVE CATEGORIES

Reserves were assigned to the proved developed producing (PDP), proved developed non-producing (PDNP), proved developed behind pipe (PDBP), and proved undeveloped (PUD) reserve categories. Oil and gas reserves by definition fall into one of the following categories: proved, probable, and possible. The proved category is further divided into: developed and undeveloped. The developed reserve category is even further divided into the appropriate reserve status subcategories: producing and non-producing. Non-producing reserves include shut-in and behind-pipe reserves. The proved reserves evaluated in this report conform to the *U.S. Securities and Exchange Commission Regulation S-X, Rule 210.4-10 (a)*. These reserve definitions are presented in the **Reserve Definitions** section of this report.

In our opinion the above-described estimates of Chesapeake's reserves and supporting data are, in the aggregate, reasonable. It is also our opinion that the above-described estimates of Chesapeake's proved reserves conform to the definitions of proved oil and gas reserves promulgated by the SEC.

Chesapeake has an active exploration and development program to develop their interests in certain tracts not classified as proved at this time. Future drilling may result in the reclassification of additional volumes to the proved reserve category. However, changes in the regulatory requirements for oil and gas operations may impact future development plans and the ability of the company to recover the estimated proved undeveloped reserves. The reserves and income attributable to the various reserve categories included in this report have not been adjusted to reflect the varying degrees of risk associated with them.

ECONOMIC TERMS

Net revenue (sales) is defined as the total proceeds from the sale of oil, condensate, natural gas liquids (NGL), and gas adjusted for commodity price basis differential and gathering/ transportation expense. Future net income (cashflow) is future net revenue less net lease operating expenses, state severance or production taxes, operating/development capital expenses and net salvage. Future net income

(cashflow) for nonoperated wells includes those general and administrative (G&A) deductions charged by the operator for a particular well or project on a monthly basis; operated well G&A deductions include only those expenses estimated as necessary to continue production activities. Future plugging, abandonment, and salvage costs are included at the economic life of each well or unit. No provisions for State or Federal income taxes have been made in this evaluation. The present worth (discounted cashflow) at various discount rates is calculated on a monthly basis.

PRICING AND ECONOMIC PARAMETERS

All product prices, costs, and economic parameters used in this report were supplied by Chesapeake and reviewed by DCS. Data from Chesapeake were accepted as presented. All prices used in preparation of this report were based on the twelve month unweighted arithmetic average of the first day of the month price for the period January through December 2011. The resulting Henry Hub reference gas price used was $4.118/MMBtu and the resulting West Texas Intermediate reference oil price used was $95.973/Bbl. Henry Hub gas price and West Texas Intermediate oil price are common reference prices for natural gas and oil production in the U.S. The prices were adjusted for local differentials, gravity and Btu where applicable. These adjustments are made for each well based on the differences between the actual product prices received by well and the reference prices over a twelve month period. **Table 3** summarizes the 2011 reference prices and the resulting average prices used in this reserves evaluation. The average prices were calculated using the total future revenue by product prior to taxes and expenses divided by the total net reserves by product. As required by SEC guidelines, all pricing was held constant for the life of the projects (no escalation). Chesapeake's estimates for capital costs for all non-producing and undeveloped wells are included in the evaluation. Chesapeake has indicated to us that they have the ability and intent to implement their capital expenditure program as scheduled.

Table 3

Chesapeake Energy Corporation—Eastern Division
Oil, Gas And NGL Prices
Year End 2011 Reserves Evaluation

Product	Reference Point	Year End 2011 Reference Price	Average Price
Oil	West Texas Intermediate	$ 95.973/Bbl	$ 70.593/Bbl
NGL	West Texas Intermediate	$ 95.973/Bbl	$ 52.157/Bbl
Natural Gas	Henry Hub	$ 4.118/MMBtu	$ 3.907/Mscf

OWNERSHIP

The leasehold interests were supplied by Chesapeake and were accepted as presented. No attempt was made by the undersigned to verify the title or ownership of the interests evaluated.

GENERAL

All data used in this study were obtained from Chesapeake, public industry information sources, or the non-confidential files of DCS. A field inspection of the properties was not made in connection with the preparation of this report.

The potential environmental liabilities attendant to ownership and/or operation of the properties have not been addressed in this report. Abandonment and clean-up costs and possible salvage value of the equipment were considered in this report.

Government regulations and policies can affect Chesapeake's ability to recover oil and gas reserves and changes may cause volumes of reserves actually recovered to increase or decrease from the estimated quantities.

In the conduct of our evaluation, we have not independently verified the accuracy and completeness of information and data furnished by Chesapeake with respect to ownership interests, historical gas production, costs of operation and development, product prices, payout balances, and agreements relating to current and future operations and sales of production. If in the course of our examination something came to our attention which brought into question the validity or sufficiency of any of the information or data provided by Chesapeake, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

In evaluating the information at our disposal related to this report, we have excluded from our consideration all matters which require a legal or accounting interpretation, or any interpretation other than those of an engineering or geological nature. In assessing the conclusions expressed in this report pertaining to all aspects of oil and gas evaluations, especially pertaining to reserve evaluations, there are uncertainties inherent in the interpretation of engineering data, and such conclusions represent only informed professional judgments.

We are independent with respect to Chesapeake as provided in the SEC regulations. Neither the employment of nor the compensation received by DCS was contingent upon the values estimated for the properties included in this report.

Data and worksheets used in the preparation of this evaluation will be maintained in our files in Pittsburgh and will be available for inspection by anyone having proper authorization by Chesapeake.

We appreciate the opportunity to perform this evaluation and are available should you need further assistance in this matter.

Sincerely yours,

Denise L. Delozier
Senior Engineer

Charles M. Boyer II, PG, CPG
Consulting Services Manager – NE Basin
Advisor—Unconventional Reservoirs

Walter K. Sawyer, PE
Principal Consultant

Attachment 1

[intentionally omitted]

Reserve Definitions

SECURITIES AND EXCHANGE COMMISION
REGULATION S-X, RULE 210.4-10 (a)

RESERVES DEFINITIONS

(2) Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(5) Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

(10) Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(16) Oil and gas producing activities.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(21) Proved area. The part of a property to which proved reserves have been specifically attributed.

(22) Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified 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 oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data 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.

(iii) 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.

(iv) 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.

(v) 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.

(23) Proved properties. Properties with proved reserves.

(24) Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

(27) Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(31) Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category 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.

(i) 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.

(ii) Undrilled locations can be classified as having 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.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) Unproved properties. Properties with no proved reserves.

Exhibit 99.3

LEE KEELING AND ASSOCIATES, INC.

PETROLEUM CONSULTANTS

First Place Tower
15 East Fifth Street • Suite 3500
Tulsa, Oklahoma 74103-4350
(918) 587-5521 • Fax: (918) 587-2881

January 18, 2012

Chesapeake Energy Corporation
6206 North Western
Oklahoma City, Oklahoma 73118

Attention: Mr. Gary L. Egger,
Vice President
Reservoir Engineering

Re: Estimated Reserves and Future Net Revenue
Selected Interests Owned by
Chesapeake Energy Corporation
Constant Prices and Expenses

Gentlemen:

In accordance with the request of Chesapeake Energy Corporation (Chesapeake) in connection with its reporting requirements, we have prepared an estimate of reserves and future net revenue to be realized from interests owned by Chesapeake and located in the states of Colorado, New Mexico, Texas and Wyoming. It is our understanding that the proved reserves estimated in this report constitute approximately eight point eight per cent (8.8%) of the total proved reserves of Chesapeake. This report has been prepared for public disclosure by Chesapeake in filings with the SEC in accordance with the disclosure requirements set forth in SEC regulations. In our opinion, the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose**.** The effective date of the estimate is December 31, 2011. Our estimate was completed on January 18, 2012, and the results are summarized as follows:

ESTIMATED REMAINING

	NET RESERVES				FUTURE NET REVENUE	
						Present Worth
	Oil	Gas	NGL	Net Equiv.	Total	Disc.@10%
RESERVE CLASSIFICATION	(MBL)	(MMCF)	(MBL)	(MMCFE)*	(M$)	(M$)
Proved Developed						
Producing	32,674.650	315,254.560	11,471.060	580,128.880	3,022,651.500	1,640,966.750
Behind-Pipe	1,651.660	34,454.180	43.680	44,626.200	191,984.920	95,807.450
Non-Producing	3,168.950	15,292.930	682.840	38,403.630	246,617.020	119,929.410
Sub-Total	37,495.260	365,001.670	12,197.580	663,158.710	3,461,253.440	1,856,703.610
Proved Undeveloped	64,135.660	407,969.560	32,942.530	990,438.620	3,794,790.250	1,061,623.500
Total All Reserves	101,630.920	772,971.230	45,140.110	1,653,597.330	7,256,043.690	2,918,327.110

* Net Gas Equivalent is calculated based on a conversion factor of 6 MCF of Gas per BBL of Liquids.
Notes: (1)Totals may not agree with schedules due to roundoff.
(2) Totals exclude shut-in reserves.

For the proved developed producing, future net revenue is the amount, exclusive of income taxes, which will accrue to the subject interests from the continued operation of the properties either to depletion or through the year 2077 AD, whichever is projected first. For all other reserve categories, future net

revenue is the amount, exclusive of income taxes, which will accrue to the subject interests from the continued operation of the properties to depletion. Future net revenue should not be construed as a fair market or trading value. Provisions have been made for the cost of plugging and abandoning the properties and for the value of salvable equipment.

The preparation of this report included the use of all methods and procedures considered necessary under the circumstances.

No attempt has been made to determine whether or not the wells and facilities comply with various governmental regulations, nor have costs been included in the event they are not.

Summary forecasts of annual gross and net production, severance and ad valorem taxes, operating income, and net revenue by reserve type are included in Schedule No. 1. Also presented in Schedule No. 1 are present worth determinations at ten discount rates, ranging from 5 to 100 per cent. Schedules No. 2 and 3 are sequential listings of the individual properties based on discounted future net revenue for the various reserve categories. Schedule No. 4 is an alphabetical listing by lease name.

CLASSIFICATION OF RESERVES

Reserves assigned to the various leases and/or wells have been classified as either "proved developed" or "proved undeveloped" in accordance with the definitions of the proved reserves as promulgated by the SEC. These are as follows:

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

Proved Undeveloped Oil and Gas Reserves are 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 drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Proved Developed Oil and Gas Reserves attributed to the subject leases have been further classified as "proved developed producing," "proved developed non-producing," "proved developed behind-pipe," and "proved developed shut-in."

Proved Developed Producing Reserves are those reserves expected to be recovered from currently producing zones under continuation of present operating methods.

Proved Developed Non-Producing Reserves are those reserves expected to be recovered from zones that have been completed and tested but are not yet producing due to situations including, but not limited to, awaiting connection to a market, minor completion problems that are expected to be corrected, or reserves expected from future stimulation treatments based on analogy to nearby wells. This category also includes "proved developed shut-in reserves."

Proved Developed Behind-Pipe Reserves are those reserves currently behind the pipe in existing wells that are considered proved by virtue of successful testing or production in offsetting wells.

ESTIMATION OF RESERVES

We reviewed the production histories of the subject wells along with completion data, past operating costs, product pricing, and other relevant well data. This review confirmed that these wells were being profitably operated and that oil and gas reserves could be assigned to them.

Many of the subject wells have been producing for a considerable length of time. Reserves attributable to wells with well-defined production trends or relationships were based upon extrapolation of these trends or relationships to economic limits and/or abandonment pressures.

Reserves anticipated from new wells were based upon volumetric calculations or analogy with similar properties, which are producing from the same horizons in the respective areas. Structural position, net pay thickness, well productivity, gas-oil ratios, water production, pressures and other pertinent factors were considered in the estimations of these reserves.

Reserves classified as non-producing and/or shut in are attributable to remedial work or stimulations to be performed on the currently perforated zones, i.e., fracture treatments or pumping unit installation. These reserves are based on volumetric calculations and/or analogy with other wells in the area producing from the same horizon.

Reserves assigned to behind-pipe zones have been estimated based on volumetric calculations and/or analogy with other wells in the area producing from the same horizon.

Primary reserves attributable to undeveloped locations have been based on volumetric calculations and/or analogy with offsetting wells.

Our estimate of reserves used all methods and procedures considered necessary, under the circumstances, to prepare this report.

FUTURE NET REVENUE

Pricing Provisions

The unit price used throughout this report for crude oil, condensate and natural gas is based upon the appropriate price in effect the first trading day of each month from January 1, 2011 through December 1, 2011.

Oil Income

Income from the sale of oil was estimated using the average price received for oil sold from the subject properties the first day of each month during 2011. These prices were provided by the staff of Chesapeake. The average price, $95.973 per barrel, was held constant throughout the economic life determined for each well. Adjustments for each well were made for state severance and ad valorem taxes and for the historical difference between the actual field price received and the above reference price.

Gas Income

Income from the sale of gas was also estimated using the average price received for gas sold from the subject properties the first day of each month during 2011. These prices were provided by the staff of Chesapeake. The average price, $4.118 per million cubic feet, was held constant throughout the economic life determined for each well. Adjustments for each well were made for state severance and ad valorem taxes and for the historical difference between the actual field price received and the above-referenced price.

NGL Income

Income from the sale of natural gas liquids (NGLs) was estimated using prices that resulted in an average price of $32.793 per barrel, which represents approximately thirty-four per cent (34%) of the oil reference price noted above, and are based on information that was provided by the staff of Chesapeake. The prices were held constant through the economic life determined for each well. Adjustments for each well were made for any state severance and ad valorem taxes and the historical difference between actual field price received and the referenced price.

Operating Expenses

Operating expenses and data used to determine operating expenses were provided by the staff of Chesapeake. These expenses are based upon the actual operating costs charged by the respective operators or are based upon the actual experience of the operators in the various areas. Like income, expenses have also been held constant throughout the life of each lease. Monthly operating costs for Chesapeake-operated wells do not include COPAS overhead charges. They do, however, include Chesapeake's actual overhead expenses for the Chesapeake-operated wells.

Future Expenditures

Future expenditures have been based on the data provided by the staff of Chesapeake.

GENERAL

The assumptions, data, methods and procedures used are appropriate for the purpose served by the report.

Information upon which this estimate has been based was furnished by the staff of Chesapeake or was obtained by us from outside sources we consider to be reliable. This information is assumed to be correct. No attempt has been made to verify title or ownership of the subject properties.

Leases were not inspected by a representative of this firm, nor were the wells tested under our supervision; however, the performance of the wells was discussed with employees of Chesapeake.

This estimate has been prepared utilizing methods and procedures regularly used by petroleum engineers to estimate oil and gas reserves for properties of this type and character. We consider the assumptions, data, methods and procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves and future net revenue herein. The recovery of oil and gas reserves and projection of producing rates are dependent upon many variable factors, including prudent operation, compression of gas when needed, market demand, installation of lifting equipment, and remedial work when required. Government regulations and policies affect Chesapeake's ability to recover oil and gas reserves, and changes may cause volumes of reserves actually recovered to increase or decrease from the estimated quantities. The reserves included in this report have been based upon the assumption that the wells will continue to be operated in a prudent manner under the same conditions existing at the present time. Actual production results and future well data may yield additional facts, not presently available to us, which will require an adjustment to our estimates.

The reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and, if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts. As in all aspects of oil and gas estimation, there are uncertainties inherent in the interpretation of engineering data and, therefore, our conclusions necessarily represent only informed professional judgments.

The projection of cash flow has been made assuming constant prices. There is no assurance that prices will not vary. For this reason and those listed in the previous paragraph, the future net cash from the sale of production from the subject properties may vary from the estimates contained in this report.

It is our opinion that based upon our knowledge of current facts and conditions, the reserves presented in this report are a reasonable measure of Chesapeake's reserves.

The information developed during the course of this investigation, basic data, maps and worksheets showing recovery determinations are available for inspection in our office.

Lee Keeling and Associates, Inc., Chesapeake's third-party engineer, has been preparing estimates of reserves and future net revenue for more than fifty years. This report was prepared under the direction of its President, who has a Bachelor of Science Degree in Petroleum Engineering and has more than fifty years' experience in estimating and evaluating reserve information.

We appreciate this opportunity to be of service to you.

Very truly yours,

LEE KEELING AND ASSOCIATES, INC.

/s/ Gordon L. Romine

Gordon L. Romine
President

LKA7126

Exhibit 99.4

Chesapeake Energy Corporation

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2011

\s\ Don P. Griffin
Don P. Griffin, P.E.
TBPE License No. 64150
Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235 TELEPHONE (713) 651-9191

January 23, 2012

Chesapeake Energy Corporation
6100 North Western Avenue
Oklahoma City, Oklahoma 73118

Gentlemen:

At your request, Ryder Scott Company (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Chesapeake Energy Corporation (Chesapeake) as of December 31, 2011. The subject properties are located in the states of Kansas, Oklahoma and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 6, 2012 and presented herein, was prepared for public disclosure by Chesapeake in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott account for a portion of Chesapeake's total net proved reserves as of December 31, 2011. Based on information provided by Chesapeake, the third party estimate conducted by Ryder Scott addresses 22.4 percent of the total net proved developed reserve and 15.7 percent of the undeveloped reserve.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2011, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized on the following page.

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
Chesapeake Energy Corporation
As of December 31, 2011

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate – MBarrels	34,474	2,117	49,714	86,305
Plant Products – MBarrels	60,411	2,485	55,386	118,282
Gas – MMCF	1,521,131	142,536	728,452	2,392,119
Income Data (M$)				
Future Gross Revenue	$ 10,264,065	$ 754,955	$ 8,578,678	$ 19,597,698
Deductions	2,313,313	178,239	3,352,383	5,843,935
Future Net Income (FNI)	$ 7,950,752	$ 576,716	$ 5,226,295	$ 13,753,763
Discounted FNI @ 10%	$ 3,996,988	$ 207,426	$ 1,853,477	$ 6,057,891

Liquid hydrocarbons are expressed in thousands of standard 42 gallon barrels (MBarrels). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package Aries™ System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used solely at the request of Chesapeake. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 60.9 percent and gas reserves account for the remaining 39.1 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income ($) As of December 31, 2011 Total Proved
5	$8,438,506
8	$6,830,585
12	$5,441,037
14	$4,937,525

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Definitions" in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes included herein do not attribute gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Chesapeake's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward. The proved reserves included herein were estimated using deterministic methods. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical),

engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Chesapeake's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Chesapeake owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods**.** Approximately 96 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods**.** The performance methods, such as decline curve analysis, utilized extrapolations of historical production and pressure data available through October, 2011 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Chesapeake or obtained from public data sources and were considered sufficient for the purpose thereof. Methods other than performance were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

Approximately 98 percent of the proved developed non-producing and undeveloped reserves included herein were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well data furnished to Ryder Scott by Chesapeake that were available through October, 2011. The data utilized from the analogues in conjunction with well data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Chesapeake has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Chesapeake with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Chesapeake. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Chesapeake. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Chesapeake furnished us with the above mentioned average prices in effect on December 31, 2011. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Chesapeake. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Chesapeake to determine these differentials

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
United States	Oil/Condensate	WTI Cushing	$ 95.97/Bbl	$ 89.29/Bbl
	NGLs	WTI Cushing	$ 95.97/Bbl	$ 41.64/Bbl
	Gas	Henry Hub – Colorado Interstate	$ 4.118/MMBTU	$ 3.39/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report are based on the operating expense reports of Chesapeake and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs shown as "Other Costs". The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished by Chesapeake were reviewed by us for their reasonableness using information furnished by Chesapeake for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Chesapeake and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were significant. The estimates of the net abandonment costs furnished by Chesapeake were accepted without independent verification.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Chesapeake's plans to develop these reserves as of December 31, 2011. The implementation of Chesapeake's development plans as presented to us and incorporated herein is subject to the approval process adopted by Chesapeake's management. As the result of our inquires during the course of preparing this report, Chesapeake has informed us that the

development activities included herein have been subjected to and received the internal approvals required by Chesapeake's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Chesapeake. Additionally, Chesapeake has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

Current costs were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Chesapeake. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Chesapeake.

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Chesapeake makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Chesapeake has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Chesapeake of the references to our name as well as to the references to our third party report for Chesapeake, which appears in the December 31, 2011 annual report on Form 10-K of Chesapeake. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Chesapeake.

We have provided Chesapeake with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Chesapeake and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,
RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580
\s\ Don P. Griffin
Don P. Griffin, P.E.
TBPE License No. 64150
Senior Vice President

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Don P. Griffin was the primary technical person responsible for overseeing the estimate of the reserves, future production and income presented herein.

Mr. Griffin, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1981, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Griffin served in a number of engineering positions with Amoco Production Company. For more information regarding Mr. Griffin's geographic and job specific experience, please refer to the Ryder Scott Company website at http://www.ryderscott.com/Experience/Employees.php.

Mr. Griffin graduated with honors from Texas Tech University with a Bachelor of Science degree in Electrical Engineering in 1975 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Griffin fulfills. Mr. Griffin attended an additional 15 hours of training during 2011 covering such topics as reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 30 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Griffin has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

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PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified 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 oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(ii) In the absence of data 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.

(iii) 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.

(iv) 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.

(v) 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.

RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

> *(i) 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; and*
>
> *(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.*

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate, but which have not started producing;

(2) wells which were shut-in for market conditions or pipeline connections; or

(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) 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.

(ii) Undrilled locations can be classified as having 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.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.