CHESAPEAKE ENERGY CORP
Form 10-K
March 01, 2010
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the Fiscal Year Ended December 31, 2009

¨ **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
7.5% Senior Notes due 2013	New York Stock Exchange
7.625% Senior Notes due 2013	New York Stock Exchange
7.0% Senior Notes due 2014	New York Stock Exchange
7.5% Senior Notes due 2014	New York Stock Exchange
6.375% Senior Notes due 2015	New York Stock Exchange
9.5% Senior Notes due 2015	New York Stock Exchange
6.625% Senior Notes due 2016	New York Stock Exchange
6.875% Senior Notes due 2016	New York Stock Exchange
6.5% Senior Notes due 2017	New York Stock Exchange
6.25% Senior Notes due 2018	New York Stock Exchange
7.25% Senior Notes due 2018	New York Stock Exchange
6.875% Senior Notes due 2020	New York Stock Exchange
2.75% Contingent Convertible Senior Notes due 2035	New York Stock Exchange
2.5% Contingent Convertible Senior Notes due 2037	New York Stock Exchange
2.25% Contingent Convertible Senior Notes due 2038	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	New York Stock Exchange

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

None

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES x NO ¨

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2009 was approximately $12.5 billion. At February 24, 2010, there were 651,861,064 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2010 Annual Meeting of Shareholders are incorporated by reference in Part III.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

2009 ANNUAL REPORT ON FORM 10-K

TABLE OF CONTENTS

Table of Contents

Part I

ITEM 1. *Business*

General

We are the second-largest producer of natural gas in the United States. We own interests in approximately 44,100 producing natural gas and oil wells that are currently producing approximately 2.4 billion cubic feet equivalent, or bcfe, per day, 93% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S., primarily in our Big 6 natural gas shale plays: the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville and Bossier Shales in the Ark-La-Tex area of northwestern Louisiana and East Texas, the Fayetteville Shale in the Arkoma Basin of central Arkansas, the Marcellus Shale in the northern Appalachian Basin of West Virginia, Pennsylvania and New York and the Eagle Ford Shale in South Texas. We also have substantial operations in the Granite Wash Plays of western Oklahoma and the Texas Panhandle regions as well as various other plays, both conventional and unconventional, in the Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the U.S.

We have been developing expertise in horizontal drilling technology since shortly after our inception in 1989 and have focused almost exclusively on developing natural gas properties in the U.S. since 2000. We were one of the first companies to recognize the potential of unconventional natural gas properties, especially shales, in the U.S. during the early part of the prior decade. During the past five years, we have grown from the eighth-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. We have recently announced that we are extending our strategy to apply the horizontal drilling expertise we have gained in our natural gas shale plays to unconventional oil reservoirs. We expect to begin increasing our production of oil and natural gas liquids in 2010 in new developing unconventional oil plays, particularly in the Granite Wash and Eagle Ford.

During 2009, our estimated proved reserves grew from 12.051 trillion cubic feet equivalent, or tcfe, to 14.254 tcfe, of which 95% were natural gas, 58% were proved developed and 100% were onshore in the U.S. We replaced our 906 bcfe of production with an estimated 3.109 tcfe of new proved reserves for a reserve replacement rate of 343%. Reserve replacement through the drillbit was 3.296 tcfe, or 364% of production, including 445 bcfe of downward revisions resulting from changes to previous estimates and 952 bcfe of downward revisions resulting from lower natural gas prices using the average 12-month price in 2009 compared to the spot price as of December 31, 2008. During 2009, we acquired 33 bcfe of estimated proved reserves and divested 220 bcfe of estimated proved reserves.

Chesapeake continued the industry s most active drilling program in 2009 and drilled 1,212 gross operated wells (885 net) and participated in another 994 gross wells operated by other companies (118 net). The company s drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during 2009, we invested $2.941 billion in operated wells (using an average of 104 operated rigs) and $439 million in non-operated wells (using an average of 60 non-operated rigs) for total drilling, completing and equipping costs of $3.380 billion.

Table of Contents

During the second half of 2008 and in early 2010, we entered into joint venture arrangements that monetized a portion of our investment in five of our shale plays and provided drilling cost carries for our retained interest. The following table provides information about our joint ventures ($ in millions):

Shale Play	Joint Venture Partner[a]	Joint Venture Date	Proceeds Received at Closing	Total Drilling Carries	Drilling Carries Remaining
Haynesville and Bossier	PXP	July 2008	$ 1,650	$ 1,508[b]	$
Fayetteville	BP	September 2008	1,100	800	
Marcellus	STO	November 2008	1,250	2,125	1,963[c]
Barnett	TOT	January 2010	800	1,450	1,450[d]
			$ 4,800	$ 5,883	$ 3,413

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

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

(c) As of December 31, 2009

(d) As of January 26, 2010

Collectively, in these four joint ventures, we received upfront cash payments of $4.8 billion and future drilling cost carries of up to $5.9 billion for total consideration of up to $10.7 billion against a cost basis of approximately $2.7 billion in the property interests we sold. Moreover, Chesapeake retained an 80% interest in the Haynesville and Bossier Shale properties, a 75% interest in the Fayetteville Shale properties, a 67.5% interest in the Marcellus Shale properties and a 75% interest in the Barnett Shale properties.

In September 2009, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, we contributed 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 to a new entity, Chesapeake Midstream Partners, L.L.C. (CMP), and GIP purchased a 50% interest in CMP for $588 million in cash.

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 and investor information on our website in addition to copies of all recent press releases. References to us , we and our in this report refer to Chesapeake Energy Corporation together with its subsidiaries.

Business Strategy

Since our inception in 1989, Chesapeake s goal has been to create value for investors by building one of the largest onshore natural gas resource bases in the United States. For the past twelve years, our strategy to accomplish this goal has been to focus on developing unconventional plays onshore in the U.S., where we believe we can generate the most attractive risk-adjusted returns. In building our industry-leading natural gas resource base during the period from 1998 to 2009, we integrated an aggressive and technologically-advanced drilling program with an active property consolidation program focused on small to medium-sized corporate and property acquisitions. During the past three

2

Table of Contents

years, we have shifted our strategy from drilling inventory capture to drilling inventory conversion and monetization. In doing so, we have de-emphasized acquisitions of proved properties, further emphasizing our industry-leading drilling program to convert our substantial backlog of drilling opportunities into proved developed producing reserves through the drillbit and also focused on capturing value by selling a portion of our leasehold and producing properties. Key elements of this business strategy are further explained below.

Grow Through the Drillbit. We believe that our most distinctive characteristic is our commitment and ability to grow production and reserves organically through the drillbit. We are currently utilizing 118 operated drilling rigs and 70 non-operated drilling rigs to conduct the most active drilling program in the U.S. We are active in most of the unconventional plays in the U.S., where we drill more horizontal wells than any other company in the industry. For several years, we have been actively investing in leasehold, 3-D seismic information and human capital to take full advantage of our capacity to grow through the drillbit. We are one of the few large-cap independent natural gas and oil companies that have been able to consistently increase production, which we have successfully achieved for the past 20 consecutive years. We believe the key elements of the success and scale of our drilling programs have been our recognition earlier than most of our competitors that new horizontal drilling and completion techniques would enable development of previously uneconomic natural gas and oil reservoirs and that, as a consequence, various shale formations could be recognized and developed as potentially prolific natural gas and oil reservoirs rather than just as source rocks for conventional reservoirs. In response to our early recognition of these trends, we have proactively hired thousands of new employees and have built the nation s largest onshore leasehold and 3-D seismic inventories. These stand as the building blocks of our successful large-scale drilling program and the foundation of value creation for our company.

Control Substantial Land and Drilling Location Inventories. After we identified the trends discussed above, we initiated a plan to build and maintain the largest inventory of onshore drilling opportunities in the U.S. Recognizing that better horizontal drilling and completion technologies when applied to various new shale plays would likely create a unique opportunity to capture decades worth of drilling opportunities, we embarked on a very aggressive lease acquisition program which we have referred to as the land rush . We believed that the winner of the land rush would enjoy a distinctive competitive advantage for decades to come as other companies would be locked out of the best new shale plays in the U.S. We believe that we have executed our land acquisition strategy with particular distinction. At December 31, 2009, we owned approximately 13.2 million net acres of leasehold in the U.S. and have identified approximately 35,750 drilling opportunities on this leasehold. We believe this deep backlog of drilling, more than ten years worth at current drilling levels, provides unusual confidence and transparency into our future growth capabilities.

Develop Proprietary Technological Advantages. In addition to our industry-leading leasehold position, we have developed a number of proprietary technological advantages. First, we have acquired what we believe is the nation s largest inventory of three-dimensional (3-D) seismic information. Possessing this 3-D seismic data enables us to image reservoirs of natural gas that might otherwise remain undiscovered and to drill our horizontal wells more accurately inside the targeted shale formation and avoid various underground geohazards such as faults and karsts. In addition, we have developed an industry-leading information-gathering program that gives us insight into new plays and competitor activity. As a result of our initiatives, we now produce approximately 4% of the nation s natural gas, drill approximately 12% of its wells and participate in almost an equal number of wells drilled by others. By gathering this information on a real-time basis, then quickly assimilating and analyzing the information, we are able to react quickly to opportunities that are created through our drilling program and those of our competitors. Furthermore, we have established a unique state-of-the-art Reservoir Technology Center (RTC) in Oklahoma City. The RTC enables us to more quickly, accurately and confidentially analyze core data from shale wells on a proprietary basis and

Table of Contents

then identify new plays and leasing opportunities ahead of our competition to improve existing plays. It also allows us to design fracture stimulation procedures that might work most productively in the shale formations that we target. We believe the RTC provides a very substantial competitive advantage in developing new shale plays and improving existing shale plays.

Build Regional Scale. We believe one of the keys to success in the natural gas exploration industry is to build significant operating scale in a limited number of operating areas that share many similar geological and operational characteristics. Achieving such scale provides many benefits, including superior geoscientific and engineering information, higher per unit revenues, lower per unit operating costs, greater rates of drilling success, higher returns from more easily integrated acquisitions and higher returns on drilling investments. By focusing most of our future activities in the Big 6 shale plays and the Granite Wash plays, we will continue to achieve even greater regional scale in North Texas for the Barnett, northwestern Louisiana and East Texas for the Haynesville and the Bossier, central Arkansas for the Fayetteville, northeastern and southwestern Pennsylvania and northwestern West Virginia for the Marcellus, South Texas for the Eagle Ford and western Oklahoma and the Texas Panhandle for the Granite Wash.

Focus on Low Costs. By minimizing lease operating costs and general and administrative expenses through focused activities, vertical integration and increased scale, we have been able to deliver attractive profit margins and financial returns through all phases of the commodity price cycle. We believe our low cost structure is the result of management s effective cost-control programs, a high-quality asset base, extensive and competitive services and natural gas processing and transportation infrastructures that exist in our key operating areas. In addition, to control costs and service provider quality, we have made significant investments in our drilling rig and trucking service operations and in our midstream gathering and compression operations that create substantial benefits from vertical integration. As of December 31, 2009, we operated approximately 25,150 of our 44,100 wells, which delivered approximately 80% of our daily production volume. This large percentage of operated properties provides us with a high degree of operational flexibility and cost control.

Mitigate Natural Gas and Oil Price Risk. We have used and intend to continue using hedging programs to mitigate the risks inherent in developing and producing natural gas and oil reserves, commodities that are often characterized by significant price volatility. If this price volatility continues in the years ahead, 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. As of February 17, 2010, we have natural gas and oil swaps and collars in place covering approximately 60% of our expected production in 2010 at average prices of $8.16 per mcfe, thereby providing price certainty for a substantial portion of our future cash flow.

Form Unique Joint Venture Arrangements. In the second half of 2008 and early 2010, the company entered into four joint venture arrangements covering five of the company s Big 6 shale plays. In the joint ventures, the company has collaborated with other leading energy companies to accelerate the development of the company s properties in the Haynesville and Bossier Shales, the Fayetteville Shale, the Marcellus Shale and the Barnett Shale. To date, we have sold leasehold and producing property assets in which we had a cost basis of approximately $2.7 billion to these four joint venture partners for total cash consideration of $4.8 billion and up to $5.9 billion of future drilling cost carries while we retained a majority interest in each joint venture. The drilling cost carries of approximately $2.0 billion that remained unused as of December 31, 2009 and the additional $1.45 billion in the Barnett Shale will be extremely valuable in the years ahead by enabling the company to develop reserves in these joint venture shale plays at greatly reduced costs. We are also considering opportunities for other joint venture transactions to develop our properties. Our 50/50 joint venture with Global Infrastructure Partners in September 2009 is another example of us joining with a strong partner to develop key assets, in this case, our midstream assets in the Barnett Shale and other midstream assets in the Mid-Continent. Upon the closing of this transaction, we received proceeds of $588 million.

Maintain an Entrepreneurial Culture. Chesapeake was formed in 1989 with an initial capitalization of $50,000 and fewer than ten employees. We completed our initial public offering of common stock in early 1993 and subsequent to those early corporate milestones, our management team has guided the company through various operational and industry challenges and extremes of natural gas and oil prices to create the second-largest independent producer of natural gas in the U.S. with approximately 8,200 employees currently. The company takes pride in its innovative and aggressive implementation of its business strategy and strives to be as entrepreneurial today as it has been in its past. We have maintained an unusually flat organizational structure as we have grown to help ensure that important information travels rapidly through the company and decisions are made and implemented quickly.

Improve our Balance Sheet. Among our large-cap peers in the natural gas exploration and production industry, we are the only company without an investment grade credit rating. We believe this is a competitive disadvantage and we intend to address this issue in the years ahead by reducing our debt and by growing our asset base such that by year-end 2011, our long-term debt divided by our estimated proved reserves results in long-term debt per mcfe that is less than $0.60 per mcfe compared to $0.84 per mcfe at year-end 2009. We believe the reduction in our debt will lower our borrowing costs, reduce concerns about our ability to access capital markets if such access were needed, increase our financial flexibility, improve our hedging capabilities and increase our stock market valuation.

Outlook

We believe that demand for natural gas will increase in the U.S. and around the world because of its favorable environmental characteristics and its great abundance. This outlook is gathering more national attention when compared to oil, which is likely to return to being in increasingly short supply once the current worldwide economic slowdown is over, and to coal, which has many unfavorable environmental characteristics. Chesapeake s strategy for 2010 is to continue developing our natural gas assets, especially in our Big 6 Shale plays, in which we anticipate investing approximately 75% of our drilling capital in 2010, through exploratory and developmental drilling. In addition, we are taking steps to increase our production of oil and natural gas liquids in 2010 in new unconventional plays such as the Granite Wash and Eagle Ford. We project that our 2010 production will be between 975 bcfe and 995 bcfe, an 8% to 10% increase over 2009 production. We have budgeted $3.3 billion for drilling capital expenditures, net leasehold and producing property transactions, seismic and other property, plant and equipment capital expenditures, which we expect to fund with operating cash flow based on our current assumptions in our 2010 financial plan. Our budget is frequently adjusted based on changes in natural gas and oil prices, drilling results, drilling costs and other factors.

Operating Areas

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

Barnett Shale. Chesapeake s Barnett Shale proved reserves represented 3.434 tcfe, or 24%, of our total proved reserves as of December 31, 2009. During 2009, the Barnett Shale assets produced 238 bcfe, or 26%, of our total production, and we invested approximately $1.197 billion to drill 417 (339 net) wells in the Barnett Shale. For 2010, we anticipate spending approximately $480 million, or 11% of our total budget, for exploration and development activities, net of carries, in the Barnett Shale. Total, our joint venture partner in the Barnett Shale, will pay 60% of our drilling, completion and equipping costs in the play over the next few years. Of the total $1.45 billion drilling cost carry, we expect approximately $500 million will be applied in 2010.

Table of Contents

Fayetteville Shale. Chesapeake s Fayetteville Shale proved reserves represented 2.167 tcfe, or 15%, of our total proved reserves as of December 31, 2009. During 2009, the Fayetteville Shale assets produced 91 bcfe, or 10%, of our total production, and we invested approximately $179 million to drill 774 (209 net) wells in the Fayetteville Shale. BP, our joint venture partner in the Fayetteville Shale, paid $601 million in carries of our drilling, completion and equipping costs on these wells in 2009. For 2010, we anticipate spending approximately $450 million, or 11% of our total budget, for exploration and development activities in the Fayetteville Shale.

Haynesville Shale (including the Bossier Shale). Chesapeake s Haynesville Shale proved reserves represented 1.834 tcfe, or 13%, of our total proved reserves as of December 31, 2009. During 2009, the Haynesville Shale assets produced 85 bcfe, or 10%, of our total production, and we invested approximately $744 million to drill 337 (163 net) wells in the Haynesville Shale. Our joint venture partner in the Haynesville Shale, PXP, paid $390 million in carries of our drilling, completion and equipping costs on these wells in 2009 along with the $1.1 billion in September 2009 as a result of the amendment to the joint venture agreement. For 2010, we anticipate spending approximately $1.785 billion, or 42% of our total budget, for exploration and development activities in the Haynesville Shale.

Marcellus Shale. Chesapeake s Marcellus Shale proved reserves represented 259 bcfe, or 2%, of our total proved reserves as of December 31, 2009. During 2009, the Marcellus Shale assets produced 15 bcfe, or 2%, of our total production, and we invested approximately $145 million to drill 149 (74 net) wells in the Marcellus Shale. Our joint venture partner in the Marcellus Shale, Statoil, paid $162 million in carries of our drilling, completion and equipping costs on these wells in 2009. For 2010, we anticipate spending approximately $360 million, or 8% of our total budget, for exploration and development activities, net of carries, in the Marcellus Shale. Statoil will pay 75% of our drilling, completion and equipping costs in the play over the next few years. Of the total $1.963 billion drilling cost carry remaining at December 31, 2009, we expect approximately $600 million will be applied in 2010.

Mid-Continent. Chesapeake s Mid-Continent proved reserves of 4.098 tcfe represented 29% of our total proved reserves as of December 31, 2009. During 2009, this area produced 305 bcfe, or 34%, of our 2009 production, and we invested approximately $712 million to drill 386 (144 net) wells in the Mid-Continent. For 2010, we anticipate spending approximately $800 million, or 19% of our total budget, for exploration and development activities in the Mid-Continent region, with an increased focus on the Granite Wash and other horizontal oil and liquids-rich unconventional plays.

Permian and Delaware Basins. Chesapeake s Permian and Delaware Basin proved reserves represented 741 bcfe, or 5%, of our total proved reserves as of December 31, 2009. During 2009, the Permian assets produced 75 bcfe, or 8%, of our total production, and we invested approximately $322 million to drill 93 (42 net) wells in the Permian and Delaware Basins. For 2010, we anticipate spending approximately $175 million, or 4% of our total budget, for exploration and development activities in the Permian and Delaware Basins, with an increased focus on various horizontal oil and liquids-rich unconventional plays.

South Texas/Gulf Coast/Ark-La-Tex (including the Eagle Ford Shale). The proved reserves of our South Texas/Texas Gulf Coast/Ark-La-Tex regions represented 565 bcfe, or 4%, of our total proved reserves as of December 31, 2009. During 2009, these assets produced 67 bcfe, or 7%, of our total production, and we invested approximately $197 million to drill 41 (25 net) wells in the South Texas/Texas Gulf Coast/Ark-La-Tex regions. For 2010, we anticipate spending approximately $200 million, or 5% of our total budget, for exploration and development activities in the South Texas/Texas Gulf Coast/Ark-La-Tex regions, especially in the Eagle Ford Shale of South Texas.

Appalachian Basin (excluding the Marcellus Shale). Chesapeake s Appalachian Basin proved reserves represented 1.156 tcfe, or 8%, of our total proved reserves as of December 31, 2009. During

Table of Contents

2009, the Appalachian assets produced 30 bcfe, or 3%, of our total production, and we invested approximately $44 million to drill 9 (7 net) wells in the Appalachian Basin. For 2010, we do not anticipate spending capital for exploration and development activities in the Appalachian Basin, except for our Marcellus Shale activities.

Well Data

At December 31, 2009, we had interests in approximately 44,100 (22,900 net) productive wells, including properties in which we held an overriding royalty interest, of which 36,950 (20,700 net) were classified as primarily natural gas productive wells and 7,150 (2,200 net) were classified as primarily oil productive wells. Chesapeake operates approximately 25,150 of its 44,100 productive wells. During 2009, we drilled 1,212 (885 net) wells and participated in another 994 (118 net) wells operated by other companies. We operate approximately 80% of our current daily production volumes.

Drilling Activity

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

	2009				2008				2007			
	Gross	**Percent**	**Net**	**Percent**	**Gross**	**Percent**	**Net**	**Percent**	**Gross**	**Percent**	**Net**	**Percent**
Development:												
Productive	1,971	98%	875	99%	3,479	99%	1,650	99%	3,439	98%	1,792	99%
Dry	33	2	8	1	40	1	13	1	53	2	10	1
Total	2,004	100%	883	100%	3,519	100%	1,663	100%	3,492	100%	1,802	100%
Exploratory:												
Productive	196	97%	115	96%	142	90%	63	90%	177	99%	116	99%
Dry	6	3	5	4	15	10	7	10	2	1	1	1
Total	202	100%	120	100%	157	100%	70	100%	179	100%	117	100%

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

	2009		2008		2007	
	Gross Wells	**Net Wells**	**Gross Wells**	**Net Wells**	**Gross Wells**	**Net Wells**
Big 6 Shales:						
Barnett Shale	417	339	776	600	512	410
Fayetteville Shale	774	209	814	220	464	131
Haynesville Shale	337	163	81	42	121	77
Marcellus Shale	149	74	32	23		
Bossier Shale						
Eagle Ford Shale						
Other:						
Mid-Continent	386	144	1,515	542	1,662	654
Permian and Delaware Basins	93	42	165	95	253	107
South Texas/Gulf Coast/Ark-La-Tex	41	25	164	97	228	167
Appalachian Basin	9	7	129	114	431	373
Total	2,206	1,003	3,676	1,733	3,671	1,919

At December 31, 2009, we had 153 (63 net) wells in process.

Table of Contents

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,		
	2009	**2008**	**2007**
Net Production:			
Natural gas (bcf)	834.8	775.4	655.0
Oil (mmbbl)	11.8	11.2	9.9
Natural gas equivalent (bcfe)	905.5	842.7	714.3
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 2,635	$ 6,003	$ 4,117
Natural gas derivatives realized gains (losses)	2,313	267	1,214
Natural gas derivatives unrealized gains (losses)	(492)	521	(139)
Total natural gas sales	4,456	6,791	5,192
Oil sales	656	1,066	678
Oil derivatives realized gains (losses)	33	(275)	(11)
Oil derivatives unrealized gains (losses)	(96)	276	(235)
Total oil sales	593	1,067	432
Total natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 3.16	$ 7.74	$ 6.29
Oil ($ per bbl)	$ 55.60	$ 95.04	$ 68.64
Natural gas equivalent ($ per mcfe)	$ 3.63	$ 8.39	$ 6.71
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 5.93	$ 8.09	$ 8.14
Oil ($ per bbl)	$ 58.38	$ 70.48	$ 67.50
Natural gas equivalent ($ per mcfe)	$ 6.22	$ 8.38	$ 8.40
Other Operating Income ($ per mcfe):			
Marketing, gathering and compression net margin	$ 0.16	$ 0.11	$ 0.10
Service operations net margin	$ 0.01	$ 0.04	$ 0.06
Expenses ($ per mcfe):			
Production expenses	$ 0.97	$ 1.05	$ 0.90
Production taxes	$ 0.12	$ 0.34	$ 0.30
General and administrative expenses	$ 0.38	$ 0.45	$ 0.34
Natural gas and oil depreciation, depletion and amortization	$ 1.51	$ 2.34	$ 2.57
Depreciation and amortization of other assets[(b)]	$ 0.27	$ 0.21	$ 0.21
Interest expense[(a)(b)]	$ 0.22	$ 0.22	$ 0.50

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

(b) Adjusted for the retrospective application of accounting guidance for debt with conversion and other options.

Table of Contents

Natural Gas and Oil Reserves

The tables below set forth information as of December 31, 2009 with respect to our estimated proved reserves, the associated estimated future net revenue and present value (discounted at an annual rate of 10%), of estimated future net revenue before and after future income taxes (standardized measure) at such date. Neither the pre-tax present value of estimated future net revenue nor the after-tax standardized measure is intended to represent the current market value of the estimated natural gas and oil reserves we own. All of our estimated natural gas and oil reserves are located within the United States.

	December 31, 2009		
	Natural Gas (bcf)	Oil (mmbbl)	Total (bcfe)[a]
Proved developed	7,859	78.8	8,331
Proved undeveloped	5,651	45.2	5,923
Total proved	13,510	124.0	14,254

	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue[b]	$ 16,537	$ 7,284	$ 23,821
Present value of estimated future net revenue[b]	$ 8,317	$ 1,132	$ 9,449
Standardized measure[b][c]			$ 8,203

	Natural Gas (bcf)	Oil (mmbbl)	Natural Gas Equivalent (bcfe)[a]	Percent of Proved Reserves	Present Value ($ in millions)
Big 6 Shales:					
Barnett Shale	3,433	0.2	3,434	24%	$ 1,502
Fayetteville Shale	2,167		2,167	15	1,060
Haynesville Shale	1,834		1,834	13	703
Marcellus Shale	259		259	2	331
Bossier Shale					
Eagle Ford Shale					
Other:					
Mid-Continent	3,646	75.4	4,098	29	4,280
Permian and Delaware Basins	482	43.2	741	5	850
South Texas/Gulf Coast/Ark-La-Tex	540	4.1	565	4	431
Appalachian Basin	1,149	1.1	1,156	8	292
Total	13,510	124.0	14,254	100%	$ 9,449[b]

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

(b) Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions at December 31, 2009. For the purpose of determining prices , we used the unweighted arithmetical average of the prices on the first day of each month within the 12-month period ended December 31, 2009. The prices used in our external and internal reserve reports were $3.87 per mcf of natural gas and $61.14 per barrel of oil, before price differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity hedges in place at December 31, 2009. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. Estimated future net revenue and the present value thereof differ from future net cash flows and the standardized measure thereof only because the former do not include the effects of estimated future income tax expenses ($1.2 billion as of December 31, 2009).

Table of Contents

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

(c) 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, 2009, our reserve estimates included 5.923 tcfe of reserves classified as proved undeveloped (PUD), compared to 3.960 tcfe as of December 31, 2008. This increase is partially attributable to our ability to report additional proved reserves under new reserve recognition rules as of year-end 2009 adopted by the Securities and Exchange Commission (SEC). These increases were offset by the conversion of 432 bcfe of PUDs to proved developed reserves during 2009. Additionally, we deleted approximately 2,250 previously booked PUD locations, including 580 bcfe of natural gas and oil reserves associated with locations not expected to be developed within five years. As of December 31, 2009, there were no material PUDs that have remained undeveloped for five years or more.

We invested approximately $621 million in 2009 to convert 432 bcfe of PUDs to proved developed reserves. In 2010, we estimate that we will invest approximately $929 million for PUD conversion. Our annual decline rate on producing properties is projected to be 28% from 2010 to 2011, 18% from 2011 to 2012, 14% from 2012 to 2013, 11% from 2013 to 2014 and 9% from 2014 to 2015. Of our 8.3 tcfe of proved developed reserves as of December 31, 2009, 1.0 tcfe were non-producing. Such reserves were primarily behind pipe zones.

The future net revenue attributable to our estimated proved undeveloped reserves of $7.3 billion at December 31, 2009, and the $1.1 billion present value thereof, have been calculated assuming that we will expend approximately $8.0 billion to develop these reserves. Net of joint venture cost carries, we have projected to incur $929 million in 2010, $1.6 billion in 2011, $1.5 billion in 2012 and $4.0 billion in 2013 and beyond, although the amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, product prices and the availability of capital. Chesapeake s developmental drilling schedules are subject to revision and reprioritization throughout the year resulting from unknowable factors such as the relative success in an individual developmental drilling prospect leading to an additional drilling opportunity, rig availability, title issues or delays, and the effect that acquisitions may have on prioritizing developmental drilling plans.

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, 2009. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices.

The company s estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2009, 2008 and 2007, 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.

Table of Contents

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond Chesapeake s control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates, and such revisions may be material. Accordingly, reserve estimates are often different from the actual quantities of natural gas and oil that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate. A change in price of $0.10 per mcf for natural gas and $1.00 per barrel for oil would result in a change in the December 31, 2009 present value of estimated future net revenue of our proved reserves of approximately $500 million and $60 million, respectively. The estimated future net revenue used in this analysis does not include the effects of future income taxes or hedging. The foregoing uncertainties are particularly true as to proved undeveloped reserves, which are inherently less certain than proved developed reserves and which comprise a significant portion of our proved reserves.

Reserves Price Sensitivity

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 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. 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 2009 12-month average prices reflected in our reported reserve estimates and the 10-year average future NYMEX strip prices as of December 31, 2009, which were $6.94 per mcf and $92.24 per barrel, before price differential adjustments. There is no change to our cost or other assumptions between this higher price scenario and those used in the estimation of our reported reserves.

	December 31, 2009			
	Gas (bcf)	**Oil (mmbbl)**	**Total (bcfe)**	**Present Value ($ in millions)**
2009 12-month average prices (SEC)	13,510	124.0	14,254	$ 9,449
10-year average future NYMEX strip prices as of December 31, 2009	14,751	131.4	15,540	$ 28,713

Reserves Estimation

Chesapeake s Reservoir Engineering Department prepared approximately 17% 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 87 full-time employees, consisting of 54 degreed engineers (ten serving in management capacities), 31 engineering technicians with a minimum of a four-year degree in mathematics, economics, finance or other business/science field, and two administrative persons. Eleven of our engineers are registered professional engineers with various state board certifications. The department collectively has approximately 1,450 years of engineering industry experience.

Table of Contents

Chesapeake maintains a continuous education program for engineers and technicians on new technologies and industry advancements and also offers refresher training on basic skill sets.

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

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

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

- 34 years of practical experience in petroleum engineering with 31 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 reserve estimates comprising approximately 83% of our estimated proved reserves (by volume) at year-end 2009. The portion of our estimated proved reserves prepared by each of our third-party engineering firms as of December 31, 2009 is presented below.

	% Prepared (by Volume)	**Principal Properties**
Netherland, Sewell & Associates, Inc.	59%	Barnett Shale Fayetteville Shale Haynesville Shale

		Mid-Continent (portions) Permian and Delaware Basins Ark-La-Tex (portions)
Lee Keeling and Associates, Inc.	10%	Mid-Continent South Texas/ Texas Gulf Coast (portions)
Data and Consulting Services, Division of Schlumberger Technology Corporation	7%	Marcellus Shale Appalachian Basin
Ryder Scott Company, L.P.	7%	Mid-Continent (portions) South Texas/ Texas Gulf Coast (portions)

Table of Contents

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 30 years of practical experience in petroleum engineering, with over 29 years of this experience being in the estimation and evaluation of reserves
- a registered professional engineer in the state of Texas
- Bachelor of Science Degree in Chemical Engineering

Lee Keeling and Associates, Inc.:

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

Data and Consulting Services, Division of Schlumberger Technology Corporation:

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

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

Table of Contents

Exploration and Development, Acquisition and Divestiture Activities

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

	December 31,		
	2009	2008	2007
	($ in millions)		
Development and exploration costs:			
Development drilling[a]	$ 2,729	$ 5,185	$ 4,402
Exploratory drilling	651	612	653
Geological and geophysical costs[b][c]	162	314	343
Asset retirement obligation and other	(2)	10	29
Total	3,540	6,121	5,427
Acquisition costs:			
Unproved properties[d]	2,793	8,250	2,507
Proved properties	61	355	671
Deferred income taxes		13	131
Total	2,854	8,618	3,309
Proceeds from divestitures:			
Unproved properties	(1,265)	(5,302)	
Proved properties	(461)	(2,433)	(1,142)
Total	$ 4,668	$ 7,004	$ 7,594

(a) Includes capitalized internal costs of $332 million, $326 million and $243 million, respectively.

(b) Includes capitalized internal costs of $22 million, $26 million and $19 million, respectively.

(c) Includes $29 million, $25 million and $16 million of related capitalized interest, respectively.

(d) Includes $598 million, $561 million and $296 million of related capitalized interest, respectively.

Our development costs included $621 million, $1.5 billion and $1.5 billion in 2009, 2008 and 2007, respectively, related to properties carried as proved undeveloped locations in the prior year s reserve reports.

Table of Contents

A summary of our exploration and development, acquisition and divestiture activities in 2009 by operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Acquisition of Unproved Properties	Acquisition of Proved Properties	Sales of Unproved Properties[a]	Sales of Proved Properties[a]	Total
			($ in millions)					
Big 6 Shales:								
Barnett Shale	417	339	$ 1,197	$ 209	$ 1	$	$	$ 1,407
Fayetteville Shale	774	209	179	56			3	238
Haynesville Shale	337	163	744	1,270	42	(1,074)		982
Marcellus Shale	149	74	145	1,038	15	(176)		1,022
Bossier Shale								
Eagle Ford Shale								
Other:								
Mid-Continent	386	144	712	120	3	11	109	955
Permian and Delaware Basins	93	42	322	31		(3)	(2)	348
South Texas/ Gulf Coast/ Ark-La-Tex	41	25	197	69		(23)	(571)	(328)
Appalachian Basin	9	7	44					44
Total	2,206	1,003	$ 3,540	$ 2,793	$ 61	$ (1,265)	$ (461)	$ 4,668

(a) Balance includes payments and remaining accruals for post-closing adjustments due to title defects in connection with certain 2008 joint venture and divestiture transactions.

Acreage

The following table sets forth as of December 31, 2009 the gross and net acres of both developed and undeveloped natural gas and oil leases which we hold. Gross acres are the total number of acres in which we own a working interest. Net acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our options to acquire additional acreage which have not been exercised.

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Big 6 Shales:						
Barnett Shale	194,477	160,277	202,493	129,595	396,970	289,872
Fayetteville Shale	276,148	123,384	2,078,125	1,033,437	2,354,273	1,156,821
Haynesville Shale[a]	215,754	151,439	545,240	362,806	760,994	514,245
Marcellus Shale	426,101	215,958	2,802,937	1,407,147	3,229,038	1,623,105
Eagle Ford Shale	106	106	86,360	79,862	86,466	79,968
Other:						
Mid-Continent	4,396,456	2,206,548	2,873,781	1,614,026	7,270,237	3,820,574
Permian and Delaware Basins	469,067	267,195	3,046,170	1,884,421	3,515,237	2,151,616
South Texas/Gulf Coast/Ark-La-Tex	527,081	311,430	509,894	295,441	1,036,975	606,871
Appalachian Basin	1,696,871	1,483,204	3,214,139	1,448,205	4,911,010	2,931,409
Total	8,202,061	4,919,541	15,359,139	8,254,940	23,561,200	13,174,481

(a) The Bossier Shale acreage overlaps the Haynesville Shale acreage and is included within the Haynesville Shale totals.

Table of Contents

Marketing, Gathering and Compression

Marketing

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

Our oil production is generally sold under market sensitive or spot price contracts. The revenue we receive from the sale of natural gas liquids is included in oil sales.

Our natural gas production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after transportation and processing of our natural gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. Under percentage-of-index contracts, the price per mmbtu we receive for our natural gas is tied to indexes published in *Inside FERC* or *Gas Daily*. Although exact percentages vary daily, as of February 2010, approximately 80% of our natural gas production was sold under short-term contracts at market-sensitive prices.

During 2009, sales to EDF Trading North America LLC (formerly Eagle Energy Partners, I, L.P.) of $571 million accounted for 10% of our total revenues (excluding gains (losses) on derivatives). In 2007, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $124 million and a gain of $83 million. Management believes that the loss of this customer would not have a material adverse effect on our results of operations or our financial position. No other customer accounted for more than 10% of total revenues (excluding gains (losses) on derivatives) in 2009.

Our marketing activities 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.

Midstream Gathering Operations

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

Our midstream assets were held in various wholly-owned subsidiaries of Chesapeake until February 2008 when we transferred our non-Appalachian midstream assets to our wholly-owned subsidiary Chesapeake Midstream Development, L.P. (CMD) and its subsidiaries. In September 2009, we formed a joint venture with Global Infrastructure Partners (GIP) to own and operate natural gas midstream assets. As part of the transaction, we contributed certain natural gas gathering systems that had been held by CMD and its subsidiaries to a new entity, Chesapeake Midstream Partners, L.L.C. (CMP) and GIP purchased a 50% interest in CMP for $588 million in cash. The accounting for the joint venture is described in Note 11 of the consolidated financial statements included in this report. The assets we contributed to the joint venture were substantially all of our midstream assets in the Barnett Shale and also the majority of our non-shale midstream assets in the Arkoma, Anadarko, Delaware and Permian Basins. Together, these assets constituted approximately 57% of our total midstream assets as of September 30, 2009.

Subsidiaries of CMD continue to operate our midstream assets outside of the CMP joint venture. These include natural gas gathering assets in the Fayetteville Shale, Haynesville Shale, Marcellus Shale and other areas in Appalachia. Compared to the Barnett Shale and Mid-Continent areas where the CMP midstream assets are located, these are less developed areas and will require significant build-out capital expenditures. A source of liquidity for this business is the $250 million revolving credit facility described under *Liquidity and Capital Resources* in Item 7 below. The CMD systems, which are located in Oklahoma, Texas, Colorado, New Mexico, New York, Ohio, Maryland, Louisiana, Arkansas, Pennsylvania and West Virginia, consist of approximately 1,500 miles of gathering pipelines, servicing over 900 natural gas wells.

On February 16, 2010, Chesapeake Midstream Partners, L.P. (the Partnership) filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of common units, representing limited partnership interests in the Partnership. The Partnership was formed by Chesapeake and GIP, equal indirect owners of the general partner of the Partnership, to own, operate, develop and acquire midstream assets. Upon the closing of the offering, Chesapeake and GIP will contribute CMP s interests to the Partnership and the Partnership will continue CMP s business. It is expected that the Partnership will succeed to CMP s $500 million revolving credit facility, with certain amendments, and a portion of the proceeds of the offering will be used to repay the outstanding borrowings under the midstream joint venture revolving credit facility described under *Liquidity and Capital Resources* in Item 7 below.

Compression

Since 2003, Chesapeake has expanded its compression business. Our wholly-owned subsidiary, MidCon Compression, L.L.C., operates wellhead and system compressors to facilitate the transportation of our natural gas production. In a series of transactions in 2007, 2008 and 2009, MidCon sold a significant portion of its compressor fleet, consisting of 1,685 compressors, for $370 million and entered into a master lease agreement. These transactions were recorded as sales and operating leasebacks. During 2010, we expect to take delivery of 324 new compressors that are on order for approximately $100 million, and we intend to simultaneously enter into sale/leaseback transactions with financial counterparties as the compressors are delivered, if acceptable leasing arrangements are available to us.

Service Operations

Drilling

Securing available rigs is an integral part of the exploration process and therefore owning our own drilling company is a strategic advantage for Chesapeake. In 2001, Chesapeake formed its wholly-owned drilling subsidiary, Nomac Drilling Corporation, with an investment of $26 million to build and refurbish five drilling rigs. As of December 31, 2009, Chesapeake had invested approximately $897 million to build or acquire 98 drilling rigs. In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 83 rigs for $677 million and subsequently leased back the rigs through 2018. The drilling rigs have depth ratings between 3,000 and 25,000 feet and range in drilling horsepower from

Table of Contents

525 to 2,000. These drilling rigs are currently operating in Oklahoma, Texas, Arkansas, Louisiana and Appalachia. Chesapeake is the fourth largest drilling rig contractor in the U.S.

Trucking

In 2006, Chesapeake expanded its service operations by acquiring two privately-owned oilfield trucking service companies. We now own one of the largest oilfield and heavy haul transportation companies in the industry. Our trucking business is utilized primarily to transport drilling rigs for both Chesapeake and third parties. Through this ownership, we are better able to manage the movement of our rigs. As of December 31, 2009, our fleet included 255 trucks and 19 cranes, which mainly service the Mid-Continent, Barnett Shale and Appalachian regions.

Seasonal Nature of Business

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

Competition

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

Hedging Activities

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

Regulation

General. All of our operations are conducted onshore in the United States. The U.S. natural gas and oil industry is regulated at the federal, state and local levels, and some of the laws, rules and regulations that govern our operations carry substantial penalties for noncompliance. These regulatory burdens increase our cost of doing business and, consequently, affect our profitability.

Regulation of Natural Gas and Oil Operations. Our exploration and production operations are subject to various types of regulation at the U.S. federal, state and local levels. Such regulation

Table of Contents

includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to regulation include, but are not limited to:

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

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

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

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

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

- air emissions;

the construction and operation of underground injection wells to dispose of produced saltwater and other non-hazardous oilfield wastes; and

the construction and operation of surface pits to contain drilling muds and other non-hazardous fluids associated with drilling operations.

Federal, state and local laws may require us to remove or remediate previously disposed wastes, including wastes disposed of or released by us or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations at contaminated areas, or to perform remedial well plugging operations or response actions to reduce the risk of future contamination. Federal laws, including the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and analogous state laws impose joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and persons that disposed of or arranged for the disposal of hazardous substances at the site. CERCLA and analogous state laws also authorize the U.S. Environmental Protection Agency (EPA), state environmental agencies and, in some cases, third parties to take action to prevent or respond to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such actions.

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

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

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

We have made and will continue to make expenditures to comply with environmental, health and safety regulations and requirements. These are necessary business costs in the natural gas and oil industry. Although we are not fully insured against all environmental, health and safety risks, and our insurance does not cover any penalties or fines that may be issued by a governmental authority, we maintain insurance coverage which we believe is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental, health and safety laws and regulations, as well as claims for damages to property or persons, resulting from company operations, could result in substantial costs and liabilities, including civil and criminal penalties, to Chesapeake. We believe that we are in material compliance with existing environmental, health and safety regulations. We believe that the cost of maintaining compliance with these existing regulations will not have a material adverse effect on our business, financial position and results of operation, but new or more stringent regulations could increase the cost of doing business.

Climate Change. On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The EPA has proposed two sets of regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and these regulations, if finalized, could lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. The adoption and implementation of regulations governing or limiting emissions of greenhouse gases from our equipment and operations could require us to incur additional operating costs and could adversely affect demand for the natural gas and oil we sell.

The United States Congress has been considering various bills that would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Such a program, if enacted, could require phased reductions in greenhouse gas emissions over several or many years and could authorize the issuance of a declining number of tradable allowances to sources of these emissions so that they may continue to emit greenhouse gases into the atmosphere. The creation of such a program remains uncertain, as do the timing and degree of reduction in emissions and the costs associated with any tradable emissions allowances. Although it is not possible at this time to predict the outcome of Congressional consideration of legislation concerning greenhouse gas emissions, any future federal laws or implementing regulations that may be enacted concerning greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the natural gas and oil we sell.

The potential increase in the costs of our operations resulting from any legislation or regulation to restrict emissions of greenhouse gases could include new or increased costs to operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas and oil.

Title to Properties

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

Operating Hazards and Insurance

The natural gas and oil business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. If any of these should occur, Chesapeake could 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.

Table of Contents

Chesapeake maintains a $50 million control of well policy that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. There is no assurance that this insurance will be adequate to cover all losses or exposure to liability. Chesapeake also carries a $350 million comprehensive general liability umbrella policy and a $100 million pollution liability policy. We provide workers compensation insurance coverage to employees in all states in which we operate. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks.

Facilities

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

Employees

Chesapeake had approximately 8,200 employees as of December 31, 2009.

Glossary of Natural Gas and Oil Terms

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent.

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

Bbtu. One billion British thermal units.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Mbtu. One thousand btus.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of natural gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of natural gas equivalent.

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

Table of Contents

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 arithmetical average of prices on the first day of each month within the 12-month period) and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

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

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

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

Proved Properties. Properties with proved reserves.

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

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

Proved Undeveloped Reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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

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

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

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

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

Tcf. One trillion cubic feet.

Tcfe. One trillion cubic feet of natural gas equivalent.

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.

Table of Contents

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 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 after the 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.

Table of Contents

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. Further, natural gas and oil prices do not necessarily move in tandem. Because approximately 95% of our reserves at December 31, 2009 were natural gas reserves, we are more affected by movements in natural gas prices.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2009, we had long-term indebtedness of approximately $12.3 billion, and our net indebtedness represented 49% of our total book capitalization. We had $1.936 billion and $1.250 billion of outstanding borrowings drawn under our revolving bank credit facilities at December 31, 2009 and February 26, 2010, respectively.

Table of Contents

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 revolving bank credit facilities of our midstream subsidiary and our midstream joint venture 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

- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings will increase the interest rate and fees we pay on our revolving bank credit facilities.

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

Low natural gas prices throughout 2009 resulted in a write-down of our asset carrying values, and further price declines could result in additional write-downs in the future.

We utilize the full-cost method of accounting for costs related to our natural gas and oil properties. Under this method, all such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, these capitalized costs are subject to a ceiling test which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves discounted at 10% plus the lower of cost or market value of unproved properties. The full-cost ceiling is evaluated at the end of each quarter using the unweighted arithmetical 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.

Natural gas prices were depressed throughout 2009, resulting in a write-down of our natural gas and oil property asset carrying value. 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. We also had an after-tax non-cash impairment charge to certain investments and fixed assets of approximately $183 million in 2009 as a result of lower asset valuation estimates.

The risk that we will be required to further write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are low or volatile. We may experience further ceiling test write-downs or other impairments in the future.

Table of Contents

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our corporate revolving bank credit facility and debt and equity issuances. Beginning in late 2007, we have also had significant cash proceeds from a number of asset monetization transactions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of natural gas and oil, our success in developing and producing new reserves, the orderly functioning of credit and capital markets and our ability to complete additional planned asset monetization transactions. If revenues were to decrease as a result of lower natural gas and oil prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may not be able to access additional bank debt, debt or equity or other methods of financing on an economic basis to meet these requirements.

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

Our future success depends largely upon our ability to find, develop or acquire additional natural gas and oil reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. In addition, approximately 42% of our total estimated proved reserves (by volume) at December 31, 2009 were undeveloped. By their nature, estimates of proved undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates reflect that our production rate on producing properties will decline approximately 28% from 2010 to 2011. Thus, our future natural gas and oil reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

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

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

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

At December 31, 2009, approximately 42% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflect our plans to make significant capital expenditures to convert our proved undeveloped reserves into proved developed reserves, including approximately $929 million in 2010. 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.

You should not assume that the present values referred to in this report represent the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The 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 arithmetical average of prices on the first day of each month within the 12-month period. The December 31, 2009 present value is based on $3.87 per mcf of natural gas and $61.14 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 2009 year-end reserve estimates are not directly comparable to prior estimates because of new reporting rules, and our interpretations of the new rules may differ materially from future guidance or comments issued by the SEC.

The year-end 2009 proved reserves estimates presented in this report have been prepared using new SEC disclosure rules that differ in a number of respects from prior rules. As a result of changes in the reporting rules, our reserve estimates beginning with year-end 2009 will not be directly comparable to our previously-reported reserves.

The SEC has not reviewed our or any reporting company s reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

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

Table of Contents

many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for natural gas and crude oil, costs associated with producing natural gas and oil and our ability to add reserves at an acceptable cost. We rely to a significant extent on seismic data and other advanced technologies in identifying unproved property prospects and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of unproved property or drilling a well, whether natural gas or oil is present or may be produced economically. The use of seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies. Drilling results in our newer shale plays may be more uncertain than in shale 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 shale formations to maximize recoveries will be ultimately successful when used in new shall 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.

As of December 31, 2009, we had leases on approximately 0.51 million and 1.62 million net acres, respectively, in the Haynesville and Marcellus Shale areas. A sizeable portion of this acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. While the company intends to drill sufficient wells to hold the vast majority of its leasehold in all its major plays, 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 received for our natural gas and oil sales, require us to provide collateral for hedging liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.

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

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

Hedging transactions involve the risk that counterparties, which are generally financial institutions, may be unable to satisfy their obligations to us. Although our counterparties to our multi-counterparty secured hedge facility are required to secure their hedging obligations to us under certain scenarios, if any of our counterparties were to default on its obligations to us under the hedging contracts or seek bankruptcy protection, it could have an adverse effect on our ability to fund our planned activities and

Table of Contents

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 13 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. If the collateral value falls below the coverage designated, we would be required to post cash or letters of credit with the counterparties if we did not have sufficient unencumbered natural gas and oil properties available to cover the shortfall. Future collateral requirements are dependent to a great extent on natural gas and oil prices.

Lower natural gas and oil prices could negatively impact our ability to borrow or raise additional capital.

Our corporate revolving bank credit facility limits our borrowings to the lesser of the borrowing base and the total commitments. Currently both are $3.5 billion, although one lender, Lehman Brothers Commercial Bank, has not funded its share (2.1%) of our borrowings under the facility beginning in the third quarter of 2008, and we do not expect that it would fund any future borrowings. The borrowing base is determined periodically at the discretion of the banks and is based in part on natural gas and oil prices. Additionally, some of our indentures contain covenants limiting our ability to incur indebtedness in addition to that incurred under our corporate revolving bank credit facility. These indentures limit our ability to incur additional indebtedness unless we meet one of two alternative tests. The first alternative is based on our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved natural gas and oil reserves as of the determination date. The second alternative is based on the ratio of our adjusted consolidated EBITDA (as defined in the relevant indentures) to our adjusted consolidated interest expense (as defined in the relevant indentures) over a trailing 12-month period. Currently, we are permitted to incur additional indebtedness under the second incurrence test but not the first test. Lower natural gas and oil prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

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

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

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

There is inherent risk of incurring significant environmental costs and liabilities in our exploration and production operations due to our generation, handling and disposal of materials, including wastes and petroleum hydrocarbons. We may incur joint and several, strict liability under applicable U.S.

Table of Contents

federal and state environmental laws in connection with releases of petroleum hydrocarbons and other hazardous substances at, on, under or from our leased or owned properties, some of which have been used for natural gas and oil exploration and production activities for a number of years, often by third parties not under our control. For our non-operated properties, we are dependent on the operator for operational and regulatory compliance. While we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

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

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

Federal Taxation of Independent Producers

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.

Derivatives Trading

The U.S. Congress is considering 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. Some proposals being considered would impose clearing and standardization requirements for all OTC derivatives and restrict trading positions in the energy futures markets. Such changes would likely materially reduce our hedging opportunities and could negatively affect our revenues and cash flow during periods of low commodity prices.

Hydraulic Fracturing

It is customary in our industry that most natural gas and oil wells use the hydraulic fracturing process. Certain environmental and other groups have suggested that additional laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and legislation has been proposed by some members of Congress to provide for such regulation. We cannot predict whether any such federal or state legislation or regulation will be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

Climate Change

The U.S. government is considering enacting new legislation or promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as our equipment and operations. The EPA has already made findings and issued proposed regulations that could lead to the imposition of restrictions on greenhouse gas emissions from stationary sources such as ours. In addition, the U.S. Congress has been considering various bills that would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Such a program, if enacted, could require phased reductions in greenhouse gas emissions over several or many years as could the issuance of a declining number of tradable allowances to sources of these emissions so that they may continue to emit greenhouse gases into the atmosphere. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could aversely 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 operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas and oil.

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

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

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

Our cash flow from operations, our revolving bank credit facilities and cash on hand historically have not been sufficient to fund all of our expenditures, and we have relied on the capital markets and asset monetization transactions to provide us with additional capital. Poor economic conditions may negatively affect:

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

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

- 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 in the Marcellus or Barnett Shale plays as agreed under our joint venture arrangements.

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

If drilling in the Haynesville and Marcellus Shales continues to be successful, the amount of natural gas being produced by us and others could exceed the capacity of the various gathering and

Table of Contents

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

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

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

None.

ITEM 2. ***Properties***

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

ITEM 3. ***Legal Proceedings***

Litigation

On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the company and certain of its officers and directors along with certain underwriters of the company s July 2008 common stock offering. Following the appointment of a lead plaintiff and counsel, the plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. The company has filed a motion to dismiss which has not been fully briefed. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against the company s directors and certain of its officers alleging breaches of fiduciary duties relating to the disclosure matters alleged in the securities case.

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

Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7, and May 20, 2009 against the company s directors alleging breaches of fiduciary duties relating to compensation of the company s CEO and alleged insider trading, among other things, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition was filed on June 23, 2009. Chesapeake is named as a nominal defendant. Chesapeake has filed a motion to dismiss which was heard on February 1, 2010. On February 26, 2010, the court ordered that plaintiffs claims be dismissed and granted plaintiffs leave to file an amended petition within 90 days.

Table of Contents

It is inherently difficult to predict the outcome of litigation, and we are currently unable to estimate the amount of any potential liabilities associated with the foregoing cases, which are all in preliminary stages.

Chesapeake is also involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, several mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The company has satisfactorily resolved several of the suits but some remain pending. The remaining leasehold acquisition cases are in various stages of discovery. The company believes that it has substantial defenses to the claims made in all these cases.

ITEM 4. Reserved.

Table of Contents

Part II

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

Price Range of Common Stock

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

	Common Stock	
	High	**Low**
Year ended December 31, 2009:		
Fourth Quarter	$ 30.00	$ 22.06
Third Quarter	$ 29.49	$ 16.92
Second Quarter	$ 24.66	$ 16.43
First Quarter	$ 20.13	$ 13.27
Year ended December 31, 2008:		
Fourth Quarter	$ 35.46	$ 9.84
Third Quarter	$ 74.00	$ 31.15
Second Quarter	$ 68.10	$ 45.25
First Quarter	$ 49.87	$ 34.42

At February 23, 2010, there were approximately 2,050 holders of record of our common stock and approximately 466,700 beneficial owners.

Dividends

The following table sets forth the amount of dividends per share declared on Chesapeake common stock during 2009 and 2008:

	2009	**2008**
Fourth Quarter	$ 0.075	$ 0.075
Third Quarter	$ 0.075	$ 0.075
Second Quarter	$ 0.075	$ 0.075
First Quarter	$ 0.075	$ 0.0675

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 and the indentures governing certain of our outstanding senior notes contain restrictions on our ability to declare and pay cash dividends. Under the corporate revolving bank credit facility and these indentures, we may not pay any cash dividends on our common or preferred stock if an event of default has occurred. These indentures further restrict cash dividends if we have not met one of the two debt incurrence tests set forth in the indentures, or if immediately after giving effect to the dividend payment, we have paid total dividends and made other restricted payments in excess of the permitted amounts. As of December 31, 2009, our coverage ratio for purposes of the debt incurrence test under the relevant indentures was 5.33 to 1, compared to a minimum of 2.25 to 1 required in such indentures. Our adjusted consolidated net tangible assets did not exceed 200% of our total indebtedness.

Table of Contents

The certificates of designation for our preferred stock prohibit payment of cash dividends on our common stock unless we have declared and paid (or set apart for payment) full accumulated dividends on the preferred stock.

Purchases of Common Stock

The following table presents information about repurchases of our common stock during the three months ended December 31, 2009:

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, 2009 through October 31, 2009	56,574	$ 26.35		
November 1, 2009 through November 30, 2009	19,013	$ 24.01		
December 1, 2009 through December 31, 2009	18,114	$ 26.13		
Total	93,701	$ 26.17		

(a) Represents 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. There are no other repurchase plans or programs currently authorized by the Board of Directors.

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

As further discussed in Note 3 of the notes to our consolidated financial statements, our consolidated financial statements for each period presented have been adjusted for the retrospective application of accounting guidance for debt with conversion and other options. The impact of the application of this standard is reflected in the table below.

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2009, 2008, 2007, 2006 and 2005. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. Changes in annual average natural gas and oil prices and increased production from drilling and acquisition activity in recent years have impacted comparability between years. See Note 10 of the notes to our consolidated financial statements. The table should be read in conjunction with *Management s Discussion and Analysis of Financial Condition and Results of Operations* and our consolidated financial statements, including the notes, appearing in Items 7 and 8 of this report.

	Years Ended December 31,				
	2009	2008	2007	2006	2005
Statement of Operations Data:	($ in millions, except per share data)				
REVENUES:					
Natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624	$ 5,619	$ 3,273

Marketing, gathering and compression sales	2,463	3,598	2,040	1,577	1,392
Service operations revenue	190	173	136	130	
Total revenues	7,702	11,629	7,800	7,326	4,665

Table of Contents

	Years Ended December 31,				
	2009	2008	2007	2006	2005
	($ in millions, except per share data)				
Statement of Operations Data (Continued):					
OPERATING COSTS:					
Production expenses	876	889	640	490	317
Production taxes	107	284	216	176	208
General and administrative expenses	349	377	243	139	64
Marketing, gathering and compression expenses	2,316	3,505	1,969	1,522	1,358
Service operations expense	182	143	94	68	
Natural gas and oil depreciation, depletion and amortization	1,371	1,970	1,835	1,359	894
Depreciation and amortization of other assets	244	174	153	103	51
Impairment of natural gas and oil properties and other assets	11,130	2,830			
Loss on sale of other property and equipment	38				
Restructuring costs	34				
Employee retirement expense				55	
Total Operating Costs	16,647	10,172	5,150	3,912	2,892
INCOME (LOSS) FROM OPERATIONS	(8,945)	1,457	2,650	3,414	1,773
OTHER INCOME (EXPENSE):					
Other income (expense)	(28)	(11)	15	26	10
Interest expense	(113)	(271)	(401)	(316)	(221)
Impairment of investments	(162)	(180)			
Loss on exchanges or repurchases of Chesapeake debt	(40)	(4)			(70)
Gain on sale of investments			83	117	
Total Other Income (Expense)	(343)	(466)	(303)	(173)	(281)
INCOME (LOSS) BEFORE INCOME TAXES	(9,288)	991	2,347	3,241	1,492
INCOME TAX EXPENSE (BENEFIT):					
Current income taxes	4	423	29	5	
Deferred income taxes	(3,487)	(36)	863	1,242	545
Total Income Tax Expense (Benefit)	(3,483)	387	892	1,247	545
NET INCOME (LOSS)	(5,805)	604	1,455	1,994	947
Net (income) loss attributable to noncontrolling interest	(25)				
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(5,830)	604	1,455	1,994	947
Preferred stock dividends	(23)	(33)	(94)	(89)	(42)
Loss on conversion/exchange of preferred stock		(67)	(128)	(10)	(26)
NET INCOME (LOSS) AVAILABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$ (5,853)	$ 504	$ 1,233	$ 1,895	$ 879
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ (9.57)	$ 0.94	$ 2.70	$ 4.76	$ 2.73
Assuming dilution	$ (9.57)	$ 0.93	$ 2.63	$ 4.33	$ 2.51
CASH DIVIDENDS DECLARED PER COMMON SHARE	$ 0.30	$ 0.2925	$ 0.2625	$ 0.23	$ 0.195
CASH FLOW DATA:					
Cash provided by operating activities	$ 4,356	$ 5,357	$ 4,974	$ 4,843	$ 2,407
Cash used in investing activities	5,462	9,965	7,964	8,942	6,921
Cash (used in) provided by financing activities	(336)	6,356	2,988	4,042	4,567

BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 29,914	$ 38,593	$ 30,764	$ 24,413	$ 16,114
Long-term debt, net of current maturities	12,295	13,175	10,178	7,187	5,286
Total equity	12,341	17,017	12,624	11,366	6,299

Table of Contents

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,		
	2009	**2008**	**2007**
Net Production:			
Natural gas (bcf)	834.8	775.4	655.0
Oil (mmbbl)	11.8	11.2	9.9
Natural gas equivalent (bcfe)	905.5	842.7	714.3
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 2,635	$ 6,003	$ 4,117
Natural gas derivatives realized gains (losses)	2,313	267	1,214
Natural gas derivatives unrealized gains (losses)	(492)	521	(139)
Total natural gas sales	4,456	6,791	5,192
Oil sales	656	1,066	678
Oil derivatives realized gains (losses)	33	(275)	(11)
Oil derivatives unrealized gains (losses)	(96)	276	(235)
Total oil sales	593	1,067	432
Total natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 3.16	$ 7.74	$ 6.29
Oil ($ per bbl)	$ 55.60	$ 95.04	$ 68.64
Natural gas equivalent ($ per mcfe)	$ 3.63	$ 8.39	$ 6.71
Average Sales Price (excluding unrealized gains (losses on derivatives):			
Natural gas ($ per mcf)	$ 5.93	$ 8.09	$ 8.14
Oil ($ per bbl)	$ 58.38	$ 70.48	$ 67.50
Natural gas equivalent ($ per mcfe)	$ 6.22	$ 8.38	$ 8.40
Other Operating Income[a] ($ in millions):			
Marketing, gathering and compression net margin	$ 147	$ 93	$ 71
Service operations net margin	$ 8	$ 30	$ 42
Other Operating Income[a] ($ per mcfe):			
Marketing, gathering and compression net margin	$ 0.16	$ 0.11	$ 0.10
Service operations net margin	$ 0.01	$ 0.04	$ 0.06
Expenses ($ per mcfe):			
Production expenses	$ 0.97	$ 1.05	$ 0.90
Production taxes	$ 0.12	$ 0.34	$ 0.30
General and administrative expenses	$ 0.38	$ 0.45	$ 0.34
Natural gas and oil depreciation, depletion and amortization	$ 1.51	$ 2.34	$ 2.57
Depreciation and amortization of other assets	$ 0.27	$ 0.21	$ 0.21
Interest expense[b]	$ 0.22	$ 0.22	$ 0.50
Interest Expense ($ in millions):			
Interest expense	$ 227	$ 192	$ 360
Interest rate derivatives realized (gains) losses	(23)	(6)	1

Interest rate derivatives unrealized (gains) losses	(91)	85	40
Total interest expense	$ 113	$ 271	$ 401
Net Wells Drilled	1,003	1,733	1,919
Net Producing Wells as of the End of Period	22,919	22,813	21,404

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

Table of Contents

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

We manage our business as three separate operational segments: exploration and production; marketing, gathering and compression (midstream); and service operations, which is comprised of our wholly-owned drilling and trucking operations. We refer you to Note 17 of the notes to our consolidated financial statements appearing in Item 8 of this report, which summarizes by segment our net income and capital expenditures for 2009, 2008 and 2007 and our assets as of December 31, 2009, 2008 and 2007.

Executive Summary

We are the second-largest producer of natural gas in the United States. We own interests in approximately 44,100 producing oil and natural gas wells that are currently producing approximately 2.4 bcfe per day, 93% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S., primarily in our Big 6 natural gas shale plays: the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville and Bossier Shales in the Ark-La-Tex area of northwestern Louisiana and East Texas, the Fayetteville Shale in the Arkoma Basin of central Arkansas, the Marcellus Shale in the northern Appalachian Basin of West Virginia, Pennsylvania and New York and the Eagle Ford Shale in South Texas. We also have substantial operations in the Granite Wash Plays of western Oklahoma and the Texas Panhandle regions as well as various other plays, both conventional and unconventional, in the Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the U.S.

We have recently announced that we are extending our strategy to apply the horizontal drilling expertise we have gained in our natural gas shale plays to unconventional oil reservoirs. We expect to begin increasing our production of oil and natural gas liquids in 2010 in new developing unconventional oil plays, particularly in the Granite Wash and Eagle Ford.

Chesapeake began 2009 with estimated proved reserves of 12.051 tcfe and ended the year with 14.254 tcfe, an increase of 2.203 tcfe, or 18%. During 2009, we replaced 906 bcfe of production with an estimated 3.019 tcfe of new proved reserves, for a reserve replacement rate of 343%. Reserve replacement through the drillbit was 3.296 tcfe, or 364% of production, including 445 bcfe of downward revisions resulting from changes to previous estimates and 952 bcfe of downward revisions resulting from lower natural gas prices using the average 12-month price in 2009 compared to the spot price as of December 31, 2008. During 2009, we acquired 33 bcfe of estimate proved reserves and divested 220 bcfe of estimated proved reserves.

Chesapeake continued the industry s most active drilling program in 2009 and drilled 1,212 gross (885 net) operated wells and participated in another 994 gross (118 net) wells operated by other companies. The company s drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during 2009, we invested $2.941 billion in operated wells (using an average of 104 operated rigs) and $439 million in non-operated wells (using an average of 60 non-operated rigs) for total drilling, completing and equipping costs of $3.380 billion.

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (13.2 million net acres) and 3-D seismic (23.6 million acres) in the U.S. We are currently using 118 operated rigs and 70 non-operated rigs to further develop our inventory of approximately 35,750 net drillsites, which represents more than a 10-year inventory of drilling projects.

Table of Contents

Business Strategy

Our exploration, acquisition and development activities require us to make substantial operating and capital expenditures. Our current budgeted drilling capital expenditures, net of drilling carries, are $4.100 billion to $4.400 billion in 2010 and $4.300 billion to $4.600 billion in 2011. We anticipate directing approximately 75% of the drilling capital expenditure (before drilling carries) during 2010 and 2011 to our Big 6 shale plays.

During 2009, our exploration and development costs were significantly lower than 2008 costs as a result of a significant decrease in drilling activity and the benefit of approximately $1.2 billion of joint venture drilling carries in four of our Big 6 shale plays. We expect exploration and development costs to generally increase in 2010, partially offset by the use of a portion of our remaining $3.4 billion of drilling carries associated with our joint ventures in the Barnett and Marcellus Shales. These drilling carries create a significant cost advantage for us that will allow us to continue to drive down finding costs. The following table provides information about the joint ventures ($ in millions):

Shale Play	Joint Venture Partner[a]	Joint Venture Date	Proceeds Received at Closing	Total Drilling Carries	Drilling Carries Remaining
Haynesville and Bossier	PXP	July 2008	$ 1,650	$ 1,508[b]	$
Fayetteville	BP	September 2008	1,100	800	
Marcellus	STO	November 2008	1,250	2,125	1,963[c]
Barnett	TOT	January 2010	800	1,450	1,450[d]
			$ 4,800	$ 5,883	$ 3,413

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

(b) In August 2009, we amended our Haynesville Shale joint venture agreement with Plains Exploration & Production Company (PXP). As part of the amendment, PXP accelerated the payment of its remaining joint venture drilling carries as of September 30, 2009 in exchange for an approximate 12% reduction in the total amount of drilling carry obligations due to Chesapeake. As a result, on September 29, 2009, Chesapeake received $1.1 billion in cash from PXP and beginning in the 2009 fourth quarter Chesapeake and PXP each began paying their proportionate working interest costs on drilling.

(c) As of December 31, 2009

(d) As of January 26, 2010

Collectively, in these four joint ventures, we received upfront cash payments of $4.8 billion and future drilling cost carries of up to $5.9 billion for total consideration of up to $10.7 billion against a cost basis of approximately $2.7 billion in the property interests we sold. Moreover, Chesapeake retained an 80% interest in the Haynesville and Bossier Shale properties, a 75% interest in the Fayetteville Shale properties, a 67.5% interest in the Marcellus Shale properties and a 75% interest in the Barnett Shale properties.

The joint ventures in our Big 6 shale plays are a complementary part of our business strategy to maximize the value of our leasehold inventory and minimize our investment risk. There are other new plays we are identifying and developing which may become additional joint venture opportunities. Our 50/50 joint venture with Global Infrastructure Partners in 2009 is another example of our joining with a strong partner to develop key assets, in this case, our midstream assets in the Barnett Shale and other midstream assets in the Mid-Continent. At the closing of this transaction, we received proceeds of $588 million. During 2009, we sold non-core natural gas and oil assets for proceeds of $418 million. Over the next two years, we expect to be a net seller of leasehold and producing properties.

42

Table of Contents

Apart from asset monetizations, cash flow from operations is our primary source of liquidity used to fund operating expenses and capital expenditures. Our $3.5 billion corporate revolving bank credit facility, our $250 million midstream revolving bank credit facility and the company s $500 million midstream joint venture revolving bank credit facility, discussed more fully in *Liquidity and Capital Resources,* provide us with additional liquidity. In February 2009, we issued $1.425 billion principal amount of our 9.5% senior notes due 2015. Net proceeds of $1.346 billion were used to repay outstanding indebtedness under our revolving bank credit facility, which we reborrow from time to time to fund drilling and leasehold acquisition initiatives and for general corporate purposes. At December 31, 2009, we had borrowings of $1.936 billion and letters of credit of $41 million outstanding under our credit facilities.

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

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity used to fund operating expenses and capital expenditures. Cash provided by operating activities was $4.356 billion in 2009, compared to $5.357 billion in 2008 and $4.974 billion in 2007. The $1.001 billion decrease from 2008 to 2009 was primarily due to lower natural gas and oil prices. The $383 million increase from 2007 to 2008 was primarily due to higher natural gas volumes and higher oil prices. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding non-cash items such as depreciation, depletion and amortization, deferred income taxes and unrealized gains and (losses) on derivatives. See the discussion below under *Results of Operations*.

Changes in market prices for natural gas and oil directly impact the level of our cash flow from operations. To mitigate the risk of declines in natural gas or oil prices and to provide more predictable future cash flow from operations, as of February 17, 2010, we have hedged through swaps and collars approximately 60% of our expected natural gas and oil production in 2010 at average prices of $8.16 per mcfe. Our natural gas and oil hedges as of December 31, 2009 are detailed in Item 7A of this report. Depending on changes in natural gas and oil futures markets and management s view of underlying natural gas and oil supply and demand trends, we may increase or decrease our current hedging positions.

Our $3.5 billion corporate revolving bank credit facility, our $250 million midstream revolving bank credit facility, our $500 million midstream joint venture revolving bank credit facility and cash and cash equivalents are other sources of liquidity. Following the January 2010 closing of our Barnett Shale joint venture with Total for $800 million in cash and the February 2010 closing of our sixth VPP transaction for $180 million in cash, as of February 26, 2010, there was $2.245 billion of borrowing capacity under the corporate credit facility, $237 million of borrowing capacity under the midstream credit facility and $482 million under the midstream joint venture credit facility. We use the facilities and cash on hand to fund daily operating activities and acquisitions as needed. We borrowed $7.8 billion and repaid $9.8

billion in 2009, we borrowed $13.3 billion and repaid $11.3 billion in 2008 and we borrowed $7.9 billion and repaid $6.2 billion in 2007 under our bank credit facilities. A substantial portion of our natural gas and oil properties is currently unencumbered and therefore available to be pledged as additional collateral under our corporate revolving bank credit facility if needed based on our periodic borrowing base and collateral redeterminations. Accordingly, we believe our borrowing capacity under this facility will not be reduced as a result of any such future periodic redeterminations. Our two midstream facilities are secured by substantially all of our midstream assets and are not subject to periodic borrowing base redeterminations.

The following table reflects the proceeds from sales of securities we issued in 2009, 2008 and 2007 ($ in millions):

	2009		2008		2007	
	Total Proceeds	**Net Proceeds**	**Total Proceeds**	**Net Proceeds**	**Total Proceeds**	**Net Proceeds**
Senior notes	$ 1,425	$ 1,346	$ 800	$ 787	$	$
Contingent convertible senior notes			1,380	1,349	1,650	1,607
Common stock			2,698	2,598		
Total	$ 1,425	$ 1,346	$ 4,878	$ 4,734	$ 1,650	$ 1,607

The following table reflects proceeds we received from our major natural gas and oil asset monetizations in 2009, 2008 and 2007 ($ in millions).

	2009	2008	2007
Natural gas and oil property monetizations:			
STO (Marcellus) joint venture(a)	$ 162	$ 1,250	$
PXP (Haynesville) joint venture(b)	1,490	1,722	
BP (Fayetteville) joint venture(c)	601	1,299	
BP (Mid-Continent) divestiture		1,688	
Volumetric production payments	408	1,579	1,089
Other divestitures	418	403	
Total	$ 3,079	$ 7,941	$ 1,089

(a) 2009 proceeds were in the form of drilling carries. As of December 31, 2009, $2.0 billion of drilling carry obligations remained outstanding.

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

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

In September 2009, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, we contributed certain natural gas gathering and processing assets into a new entity, Chesapeake Midstream Partners, L.L.C. (CMP), and GIP purchased a 50% interest in CMP for $588 million in cash.

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.

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. We refer you to the table under *Investing Activities* below, which sets forth the components of our natural gas and oil investing activities and other investing activities for 2009, 2008 and 2007. We retain a significant degree of control over the timing of our capital expenditures which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary.

We paid dividends on our common stock of $181 million, $148 million and $115 million in 2009, 2008 and 2007, respectively. The Board of Directors increased the quarterly dividend of common stock from $0.0675 to $0.075 per share beginning with the dividend paid in July 2008. Dividends paid on our preferred stock decreased to $23 million in 2009 from $35 million in 2008 and $95 million in 2007 as a result of conversions and exchanges of preferred stock into common stock during 2007, 2008 and 2009.

In 2009, 2008 and 2007, we received $24 million, and paid $167 million and $91 million, respectively, to settle a portion of the derivative liabilities assumed in our 2005 acquisition of Columbia Natural Resources, LLC. Additionally in 2009, we received $85 million for settlements of derivatives which were classified as financing derivatives.

Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers, and 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, 2009, our commodity and interest rate derivative instruments were spread among 14 counterparties. Additionally, our multi-counterparty secured hedging facility requires our counterparties to secure their natural gas and oil hedging obligations in excess of defined thresholds.

Our accounts receivable are primarily from purchasers of natural gas and oil ($743 million at December 31, 2009) and exploration and production companies which own interests in properties we operate ($394 million at December 31, 2009). 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 2009, we recognized $12 million of bad debt expense related to potentially uncollectible receivables.

Table of Contents

Investing Activities

While we continue to maintain an active drilling program and acquire leasehold and unproved property needed for planned natural gas and oil development, cash used in investing activities declined significantly in 2009. Cash used in investing activities decreased to $5.462 billion in 2009, compared to $9.965 billion in 2008 and $7.964 billion in 2007. Our investing activities in 2007 and 2008 reflected our increasing focus on acquiring unproved leasehold, converting our resource inventory into production, redeploying our capital by selling natural gas and oil properties with lower rates of return and increasing our investment in properties with higher return potential. We also invested in drilling rigs, gathering systems, compressors, and other property and equipment to support our natural gas and oil exploration, development and production activities. These activities continued in 2009, but at a reduced rate in response to a low natural gas price environment, lower demand and the benefit of our joint venture carries. The following table details our cash used in (provided by) investing activities during 2009, 2008 and 2007 ($ in millions):

	2009	2008	2007
Natural Gas and Oil Investing Activities:			
Acquisitions of natural gas and oil companies and proved properties, net of cash acquired	$ 5	$ 372	$ 520
Acquisition of leasehold and unproved properties	1,666	7,660	2,187
Exploration and development of natural gas and oil properties	3,410	5,789	4,962
Geological and geophysical costs[(a)]	162	315	343
Interest capitalized on unproved properties	598	561	296
Proceeds from sale of volumetric production payments	(408)	(1,579)	(1,089)
Deposits for acquisitions		12	15
Divestitures of proved and unproved properties and leasehold	(1,518)	(6,091)	
Total natural gas and oil investing activities	3,915	7,039	7,234
Other Investing Activities:			
Additions to other property and equipment	1,683	3,073	1,439
Proceeds from sale of drilling rigs and equipment		(64)	(369)
Proceeds from sale of compressors	(68)	(114)	(188)
Additions to investments	40	74	8
Proceeds from sale of investments		(2)	(124)
Sale of other assets	(108)	(41)	(36)
Total other investing activities	1,547	2,926	730
Total cash used in investing activities	$ 5,462	$ 9,965	$ 7,964

(a) Including related capitalized interest.

In connection with our reduced budget for acquisitions, we used 24,822,832 and 1,677,000 shares of our common stock to acquire leasehold and mineral interests in 2009 and 2008, respectively, pursuant to an acquisition shelf registration statement.

Table of Contents

Bank Credit Facilities

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

	Corporate Credit Facility	Midstream Credit Facility ($ in millions)	Midstream Joint Venture Credit Facility
Borrowing capacity	$ 3,500	$ 250	$ 500
Maturity date	November 2012	September 2012	September 2012
Borrowers	Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C.	Chesapeake Midstream Operating, L.L.C. (CMO)	Chesapeake Midstream Partners, L.L.C. (CMP)
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Amount outstanding as of December 31, 2009	$ 1,892	$	$ 44
Letters of credit outstanding as of December 31, 2009	$ 41	$	$

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, none of our credit facilities contains provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Corporate Credit Facility

Our $3.5 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by certain producing natural gas and oil properties and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A., or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.00% to 0.75% per annum according to our senior unsecured long-term debt ratings, or (ii) the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to a commitment fee of 0.50%. 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, among other things, limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness (excluding discount on senior notes) to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.44 to 1 and our indebtedness to EBITDA ratio was 3.18 to 1 at December 31, 2009. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $75 million.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly-owned restricted subsidiaries other than minor subsidiaries.

Midstream Credit Facility

Our midstream $250 million syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems to support our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the midstream credit facility are secured by all of the assets of the wholly-owned subsidiaries (the restricted subsidiaries) of Chesapeake Midstream Development, L.P. (CMD), itself a wholly-owned subsidiary of Chesapeake, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which, among other things, limit the ability of CMD and its restricted subsidiaries to incur additional indebtedness, make investments or loans, create liens and pay dividends or distributions to Chesapeake. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.01 to 1 and our EBITDA to interest expense coverage ratio was 6.87 to 1 at December 31, 2009. 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 midstream 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 subsidiaries may have with an outstanding principal amount in excess of $15 million.

Midstream Joint Venture Credit Facility

Our midstream joint venture $500 million syndicated revolving bank credit facility was established concurrent with the midstream joint venture we formed on September 30, 2009 (see Note 11 for discussion regarding the midstream joint venture). As a result of that transaction, our existing midstream credit facility was amended and restated as described above. Borrowings under the midstream joint venture credit facility are secured by all of the assets of the midstream companies organized under the joint venture, which is 50% owned by Chesapeake and 50% owned by our joint venture partner Global Infrastructure Partners, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The midstream joint venture credit facility agreement contains various covenants and restrictive provisions which, among other things, limit the ability of the joint venture and its subsidiaries to incur additional indebtedness, make investments or loans, create liens and pay dividends or distributions to

Table of Contents

Chesapeake. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.19 to 1 and our EBITDA to interest expense coverage ratio was 21.75 to 1 at December 31, 2009. If CMP or its subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream joint venture facility could be declared immediately due and payable. The midstream joint venture credit facility agreement also has cross default provisions that apply to other indebtedness CMP and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

Hedging Facilities

We began 2009 with six secured hedging facilities, each of which permitted us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a stated maximum value. Outstanding transactions under each of the facilities were collateralized by certain of our natural gas and oil properties that did not secure any of our other obligations. On June 11, 2009, we entered into a multi-counterparty hedge facility with 13 counterparties that have committed to provide approximately 3.9 tcfe of trading capacity and an aggregate mark-to-market capacity of $10.4 billion under the terms of the facility. The new multi-counterparty facility has consolidated and replaced the six secured hedge facilities. All prior trades with these counterparties have been novated and pledged collateral transferred to the multi-counterparty facility, which had a total of 1.7 tcfe hedged and collateral value of approximately $5.3 billion as of December 31, 2009. Trades from the original six secured hedging facilities will continue to be subject to pre-existing exposure fees, but we are not required to pay an exposure fee for any new trades in the multi-counterparty facility.

The multi-counterparty facility allows us to enter into cash-settled natural gas and oil price and basis hedges with the counterparties. Our obligations under the multi-counterparty 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, 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 hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease trading with the company on a prospective basis as long as obligations associated with any existing trades in the facility continue to be satisfied in accordance with the terms of the agreement.

Table of Contents

Senior Note Obligations

In addition to outstanding revolving bank credit facility borrowings discussed above, as of December 31, 2009, senior notes represented approximately $10.4 billion of our long-term debt and consisted of the following ($ in millions):

7.5% senior notes due 2013	$ 364
7.625% senior notes due 2013	500
7.0% senior notes due 2014	300
7.5% senior notes due 2014	300
6.375% senior notes due 2015	600
9.5% senior notes due 2015	1,425
6.625% senior notes due 2016	600
6.875% senior notes due 2016	670
6.25% Euro-denominated senior notes due 2017[a]	860
6.5% senior notes due 2017	1,100
6.25% senior notes due 2018	600
7.25% senior notes due 2018	800
6.875% senior notes due 2020	500
2.75% contingent convertible senior notes due 2035[b]	451
2.5% contingent convertible senior notes due 2037[b]	1,378
2.25% contingent convertible senior notes due 2038[b]	763
Discount on senior notes[c]	(921)
Interest rate derivatives[d]	69
	$ 10,359

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4332 to 1.00 as of December 31, 2009. See Note 9 for information on our related cross currency swap.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the fourth quarter of 2009, 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 2010 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	$	48.71	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$	64.36	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$	107.36	June 14, 2019

Table of Contents

(c) Included in this discount is $794 million associated with the equity component of our contingent convertible senior notes. See Note 3 of our consolidated financial statements for a description of the accounting treatment applied to these notes.

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

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

As of December 31, 2009 and currently, debt ratings for the senior notes are Ba3 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (stable outlook) and BB by Fitch Ratings (negative outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our senior note obligations are guaranteed by certain of our wholly-owned subsidiaries. See Note 18 of the financial statements included in this report for condensed consolidating financial information regarding guarantor and non-guarantor subsidiaries. We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified redemption or make-whole prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our corporate revolving credit facility. As of December 31, 2009, we estimate that corporate commercial bank indebtedness of approximately $4.4 billion could have been incurred under the most restrictive indenture covenant.

Conversions and Exchanges of Contingent Convertible Senior Notes and Preferred Stock

In 2009 and 2008, holders of certain of our contingent convertible senior notes exchanged or converted their senior notes for shares of common stock in privately negotiated exchanges as summarized below ($ in millions):

Year	Contingent Convertible Senior Notes	Principal Amount	Number of Common Shares
2009	2.25% due 2038	$ 364	10,210,169
2008	2.75% due 2035	$ 239	8,841,526
2008	2.50% due 2037	272	8,416,865
2008	2.25% due 2038	254	6,654,821
		$ 765	23,913,212

Table of Contents

In 2009, 2008 and 2007, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/ Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares	Type of Transaction
2009	6.25%	143,768	1,239,538	Conversion
	4.125%	3,033	182,887	Conversion
			1,422,425	
2008	5.0% (series 2005B)	3,654,385	10,443,642	Exchange
	4.5%	891,100	2,227,750	Exchange
	4.125%	29	1,743	Conversion
			12,673,135	
2007	5.0% (series 2005)	4,595,000	19,283,311	Exchange
	6.25%	2,156,184	17,367,823	Exchange
	6.25%	48	344	Conversion
	4.125%	3	180	Conversion
			36,651,658	

Contractual Obligations

The table below summarizes our cash contractual obligations as of December 31, 2009 ($ in millions):

		Payments Due By Period			
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt:					
Principal	$ 13,147	$	$ 1,936	$ 1,464	$ 9,747
Interest	5,780	694	1,387	1,276	2,423
Financing lease obligations and other	930	20	38	92	780
Operating lease obligations	882	147	290	278	167
Asset retirement obligations[(a)]	282	35	29	8	210
Purchase obligations[(b)]	3,082	482	674	538	1,388
Unrecognized tax benefits[(c)]	231		196	35	
Standby letters of credit	41	41			
Total contractual cash obligations	$ 24,375	$ 1,419	$ 4,550	$ 3,691	$ 14,715

(a) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2009 balance sheet.

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

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

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

Table of Contents

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

Hedging Activities

Natural Gas and Oil Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Executive management is involved in all risk management activities and the Board of Directors reviews the company s hedging program at its quarterly Board meetings. We believe we have sufficient internal controls to prevent unauthorized hedging. As of December 31, 2009, our natural gas and oil derivative instruments were comprised of swaps, collars, call options, put options, knockout swaps and basis protection swaps. Item 7A *Quantitative and Qualitative Disclosures About Market Ris*k contains a description of each of these instruments. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

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

Mark-to-market positions under natural gas and oil hedging contracts fluctuate with commodity prices. As described above under *Hedging Facilities*, 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 hedges by pledging natural gas and oil properties.

Our realized and unrealized gains and losses on natural gas and oil derivatives during 2009, 2008 and 2007 were as follows:

	Years Ended December 31,		
	2009	**2008**	**2007**
	($ in millions)		
Natural gas and oil sales	$ 3,291	$ 7,069	$ 4,795
Realized gains (losses) on natural gas and oil derivatives	2,346	(8)	1,203
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(624)	887	(252)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	36	(90)	(122)
Total natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624

Changes in the fair value of natural gas and oil derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of derivative contracts are recorded in accumulated other comprehensive income and are transferred to earnings in the month of related production. These unrealized gains (losses), net of related tax effects, totaled $94 million, $386 million and $53 million as of December 31, 2009, 2008 and 2007, respectively. Based upon the market prices at December 31, 2009, we expect to transfer to earnings approximately $202 million of the net gain included in the balance of accumulated other comprehensive income during the next 12 months. A detailed explanation of accounting for natural gas and oil derivatives appears under *Application of Critical Accounting Policies Hedging* elsewhere in this Item 7.

The estimated fair values of our natural gas and oil derivative instruments as of December 31, 2009 and 2008 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2009	December 31, 2008
	($ in millions)	
Derivative assets (liabilities)[a]:		
Fixed-price natural gas swaps	$ 662	$ 863
Fixed-price natural gas collars	92	402
Fixed-price natural gas knockout swaps	17	141
Natural gas call options	(541)	(178)
Natural gas put options	(50)	(39)
Natural gas basis protection swaps	(50)	93
Fixed-price oil swaps	3	31
Fixed-price oil collars		5
Fixed-price oil knockout swaps	32	19
Fixed-price oil cap-swaps		3
Oil call options	(144)	(35)
Estimated fair value	$ 21	$ 1,305

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

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

	2009	2008	2007
		($ in millions)	
Fair value of contracts outstanding, as of January 1	$ 1,305	$ (369)	$ 345
Change in fair value of contracts	1,266	1,880	972
Fair value of contracts when entered into	(21)	(569)	(295)
Contracts realized or otherwise settled	(2,102)	9	(1,203)
Fair value of contracts when closed	(427)	354	(188)
Fair value of contracts outstanding, as of December 31	$ 21	$ 1,305	$ (369)

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 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. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized (gains) losses within interest expense.

Table of Contents

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, 2009, 2008 and 2007 are presented below.

	Years Ended December 31,		
	2009	2008	2007
		($ in millions)	
Interest expense on senior notes	$ 765	$ 637	$ 538
Interest expense on credit facilities	60	117	113
Capitalized interest	(633)	(585)	(311)
Realized (gains) losses on interest rate derivatives	(23)	(6)	1
Unrealized (gains) losses on interest rate derivatives	(91)	85	40
Amortization of loan discount and other	35	23	20
Total interest expense	$ 113	$ 271	$ 401

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

Foreign Currency Derivatives

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

Results of Operations

General. For the year ended December 31, 2009, Chesapeake had a net loss of $5.830 billion, or a loss of $9.57 per diluted common share, on total revenues of $7.702 billion. This compares to net income of $604 million, or $0.93 per diluted common share, on total revenues of $11.629 billion during the year ended December 31, 2008, and net income of $1.455 billion, or $2.63 per diluted common share, on total revenues of $7.800 billion during the year ended December 31, 2007.

Natural Gas and Oil Sales. During 2009, natural gas and oil sales were $5.049 billion compared to $7.858 billion in 2008 and $5.624 billion in 2007. In 2009, Chesapeake produced and sold 905.5 bcfe of natural gas and oil at a weighted average price of $6.22 per mcfe, compared to 842.7 bcfe in 2008 at a weighted average price of $8.38 per mcfe, and 714.3 bcfe in 2007 at a weighted average price of $8.40 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of ($588) million, $797 million and ($374) million in 2009, 2008 and 2007, respectively). The decrease in prices in 2009 resulted in a decrease in revenue of $1.950 billion and increased production resulted in a $526 million increase, for a total decrease in revenues of $1.424 billion (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from period to period was primarily generated from the drillbit.

For 2009, we realized an average price per mcf of natural gas of $5.93, compared to $8.09 in 2008 and $8.14 in 2007 (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $58.38, $70.48 and $67.50 in 2009, 2008 and 2007, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $2.346 billion or $2.59 per mcfe in 2009, a net decrease of ($8) million or ($0.01) per mcfe in 2008 and a net increase of $1.203 billion or $1.68 per mcfe in 2007.

Table of Contents

A change in natural gas and oil prices has a significant impact on our natural gas and oil revenues and cash flows. Assuming 2009 production levels, a change of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2009 revenues and cash flows of approximately $91 million and $88 million, respectively, and a change of $1.00 per barrel of oil sold would result in an increase or decrease in 2009 revenues and cash flows of approximately $12 million and $11 million, without considering the effect of hedging activities.

The following tables show our production and prices by region for 2009, 2008 and 2007:

	2009						
	Natural Gas		Oil		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Big 6 Shales:							
Barnett Shale	237.9	$ 2.10	0.1	$ 54.80	238.1	26%	$ 2.11
Fayetteville Shale[c]	90.7	3.02			90.7	10	3.02
Haynesville Shale	85.0	3.32	0.1	48.34	85.5	10	3.35
Marcellus Shale[d]	14.8	4.05			14.8	2	4.05
Bossier Shale							
Eagle Ford Shale							
Other:							
Mid-Continent[b] [e]	258.7	3.77	7.7	55.33	305.0	34	4.60
Permian and Delaware Basins	56.7	3.49	3.0	57.25	74.9	8	4.96
South Texas/Gulf Coast/Ark-La-Tex[f]	62.5	3.75	0.7	53.19	66.7	7	4.06
Appalachian Basin[g]	28.5	3.87	0.2	53.49	29.8	3	4.08
Total	834.8	$ 3.16	11.8	$ 55.60	905.5	100%	$ 3.63

	2008						
	Natural Gas		Oil		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Big 6 Shales:							
Barnett Shale	181.2	$ 6.73		$	181.2	22%	$ 6.73
Fayetteville Shale[c]	54.8	7.23			54.8	7	7.23
Haynesville Shale	27.0	8.14	0.2	91.02	28.0	3	8.39
Marcellus Shale[d]	2.7	10.13			2.7		10.13
Bossier Shale							
Eagle Ford Shale							
Other:							
Mid-Continent[b][e]	315.9	7.87	6.9	93.66	357.3	42	8.77
Permian and Delaware Basins	63.0	7.80	2.9	97.46	80.4	10	9.63
South Texas/Gulf Coast/Ark-La-Tex	98.1	8.71	1.1	98.45	104.6	12	9.19
Appalachian Basin[g]	32.7	9.41	0.1	91.52	33.7	4	9.57
Total	775.4	$ 7.74	11.2	$ 95.04	842.7	100%	$ 8.39

Table of Contents

	2007						
	Natural Gas		Oil		Total		
	(bcf)	($/mcf)(a)	(mmbbl)	($/bbl)(a)	(bcfe)	%	($/mcfe)(a)
Big 6 Shales:							
Barnett Shale	93.3	$ 5.21		$	93.3	13%	$ 5.21
Fayetteville Shale	14.7	5.15			14.7	2	5.15
Haynesville Shale	21.6	6.72	0.2	61.40	22.9	3	6.92
Marcellus Shale							
Bossier Shale							
Eagle Ford Shale							
Other:							
Mid-Continent	327.5	6.27	5.6	68.26	360.9	50	6.75
Permian and Delaware Basins	47.2	6.51	2.7	69.77	63.4	9	7.82
South Texas/Gulf Coast/Ark-La-Tex	103.6	6.74	1.3	71.29	111.1	16	7.09
Appalachian Basin	47.1	7.42	0.1	47.67	48.0	7	7.43
Total	655.0	$ 6.29	9.9	$ 68.64	714.3	100%	$ 6.71

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

(b) 2009 and 2008 were impacted by the sale of 10.1 bcfe and 6.6 bcfe of production, respectively, related to the BP Arkoma divestiture that closed in August 2008.

(c) 2009 and 2008 were impacted by the sale of 30.3 bcfe and 5.2 bcfe of production, respectively, related to the BP Fayetteville joint venture that closed in September 2008.

(d) 2009 and 2008 were impacted by the sale of 5.4 bcfe and 0.1 bcfe of production, respectively, related to the STO Marcellus joint venture that closed in November 2008.

(e) 2009 and 2008 were impacted by the sale of 49.6 bcfe and 18.2 bcfe of production, respectively, related to various VPP transactions that closed in 2008.

(f) 2009 was impacted by the sale of 7.8 bcfe of production related to a VPP transaction that closed in 2009.

(g) 2009 and 2008 were impacted by the sale of 17.0 bcfe and 18.3 bcfe of production, respectively, related to a VPP transaction that closed in 2007.

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in 2009, 2008 and 2007.

Marketing, Gathering and Compression. Marketing, gathering and compression activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $2.463 billion in marketing, gathering and compression sales in 2009, with corresponding marketing, gathering and compression expenses of $2.316 billion, for a net margin before depreciation of $147 million. This compares to sales of $3.598 billion and $2.040 billion, expenses of $3.505 billion and $1.969 billion, and margins before depreciation of $93 million and $71 million in 2008 and 2007, respectively. In 2009 and 2008, Chesapeake realized an increase in marketing, gathering and compression net margin primarily due to an increase in third party marketing volumes.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake recognized $190 million in service operations revenue in 2009 with corresponding service operations expenses of $182 million, for a net margin before depreciation of $8 million. This compares to revenue of $173 million and $136 million, expenses of $143 million and $94 million and a net margin before depreciation of $30 million and $42 million in 2008 and 2007, respectively. These operations have grown as a result of assets and businesses we acquired and leased as seen in the growth in revenues. However, the net margins have decreased each of the previous three years. This is the result of increased expenses associated with the leasing cost of the numerous rigs we have sold and leased back in the previous three years.

Table of Contents

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $876 million in 2009, compared to $889 million and $640 million in 2008 and 2007, respectively. On a unit-of-production basis, production expenses were $0.97 per mcfe in 2009 compared to $1.05 and $0.90 per mcfe in 2008 and 2007, respectively. The expense decrease in 2009 was primarily due to lower service costs in the field as a result of the economic downturn. Our per unit decrease in 2009 was also affected by the increase in production. We expect that production expenses per mcfe produced for 2010 will range from $0.85 to $0.95.

The following table shows our production expenses by region and our ad valorem tax expenses for 2009, 2008 and 2007 ($ in millions, except per unit):

	2009		2008		2007	
	Production Expenses	$/mcfe	Production Expenses	$/mcfe	Production Expenses	$/mcfe
Big 6 Shales:						
Barnett Shale	$ 158	$ 0.66	$ 128	$ 0.71	$ 58	$ 0.62
Fayetteville Shale	23	0.25	13	0.24	7	0.41
Haynesville Shale	33	0.39	37	1.33		
Marcellus Shale	24	1.67	4	1.63		
Bossier Shale						
Eagle Ford Shale						
Other:						
Mid-Continent	300	0.98	362	1.01	285	0.80
Permian and Delaware Basins	114	1.52	134	1.67	104	1.60
South Texas/Gulf Coast/Ark-La-Tex	68	1.02	95	0.91	120	0.89
Appalachian Basin	76	2.50	42	1.24	27	0.56
Ad valorem tax	80	0.09	74	0.09	39	0.05
Total	$ 876	$ 0.97	$ 889	$ 1.05	$ 640	$ 0.90

Production Taxes. Production taxes were $107 million in 2009 compared to $284 million in 2008 and $216 million in 2007. On a unit-of-production basis, production taxes were $0.12 per mcfe in 2009 compared to $0.34 per mcfe in 2008 and $0.30 per mcfe in 2007. The $177 million decrease in production taxes from 2008 to 2009 is due to a decrease in the realized average sales price of natural gas and oil of $4.76 per mcfe (excluding gains or losses on derivatives), which more than offset the production increase of 63 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. We expect production taxes for 2010 to range from $0.25 to $0.30 per mcfe based on estimated NYMEX prices ranging from $5.25 to $6.75 per mcf of natural gas and an oil price of $80.00 per barrel.

General and Administrative Expense. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties (see Note 10 of notes to consolidated financial statements), were $349 million in 2009, $377 million in 2008 and $243 million in 2007. General and administrative expenses were $0.38, $0.45 and $0.34 per mcfe for 2009, 2008 and 2007, respectively. The decrease in 2009 was primarily the result of decreased spending related to media relations. Included in general and administrative expenses is stock-based compensation of $83 million in 2009, $85 million in 2008 and $58 million in 2007. Restricted stock grants are expensed at the price of our common stock on the date of grant. The increase in 2008 was the result of a larger number of unvested shares being expensed during 2008 compared to 2007. We anticipate that general and administrative expenses for 2010 will be between $0.39 and $0.46 per mcfe produced, including stock-based compensation ranging from $0.09 to $0.11 per mcfe produced.

Table of Contents

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

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $354 million, $352 million and $262 million of internal costs in 2009, 2008 and 2007, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $1.371 billion, $1.970 billion and $1.835 billion during 2009, 2008 and 2007, 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 $1.51, $2.34 and $2.57 in 2009, 2008 and 2007, respectively. The decrease in the average rate from $2.57 in 2007 to $1.51 in 2009 is due primarily to reductions of our natural gas and oil full-cost pool resulting from our divestitures in 2008 and 2009 and impairments of our full-cost pool in 2008 and 2009 as well as the addition of reserves through our drilling activities. We expect the 2010 DD&A rate to be between $1.35 and $1.55 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $244 million in 2009, compared to $174 million in 2008 and $153 million in 2007. The average DD&A rate per mcfe was $0.27, $0.21 and $0.21 in 2009, 2008 and 2007, respectively. The increase from 2008 to 2009 was mainly due to the significant increase in our investment in gathering systems, compressors, buildings and drilling rigs. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to twenty years. To the extent company-owned drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs. We expect 2010 depreciation and amortization of other assets to be between $0.20 and $0.25 per mcfe produced.

Impairment of Natural Gas and Oil Properties and Other Assets. Due to lower commodity prices in the second half of 2008 and throughout 2009, we reported a non-cash impairment charge on our natural gas and oil properties of $11.0 billion in 2009 and $2.8 billion in 2008. We account for our natural gas and oil properties using the full-cost method of accounting, which limits the amount of costs we can capitalize and requires us to write off these costs if the carrying value of natural gas and oil assets in the evaluated portion of our full-cost pool exceeds the sum of the present value of expected future net cash flows of proved reserves using a 10% pre-tax discount rate based on pricing and cost assumptions and the present value of certain natural gas and oil hedges. Additionally, in 2009, we recorded an impairment of $90 million associated with certain of our midstream assets and $27 million associated with certain of our service operations assets.

Other Income (Expense). Other income (expense) was ($28) million, ($11) million and $15 million in 2009, 2008 and 2007, respectively. The 2009 loss consisted of $8 million of interest income, a $39 million loss related to our equity in the net losses of certain investments, a $1 million gain on sale of assets and $2 million of miscellaneous income. The 2008 loss consisted of $22 million of interest

Table of Contents

income, a $38 million loss related to our equity in the net losses of certain investments, a $4 million gain on sale of assets, $10 million of expense related to consent solicitation fees and $11 million of miscellaneous income. The 2007 income consisted of $8 million of interest income and $7 million of miscellaneous income. Income related to equity investments was not significant in 2007.

Interest Expense. Interest expense decreased to $113 million in 2009 compared to $271 million in 2008 and $401 million in 2007 as follows:

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Interest expense on senior notes	$ 765	$ 637	$ 538
Interest expense on credit facilities	60	117	113
Capitalized interest	(633)	(585)	(311)
Realized (gain) loss on interest rate derivatives	(23)	(6)	1
Unrealized (gain) loss on interest rate derivatives	(91)	85	40
Amortization of loan discount and other	35	23	20
Total interest expense	$ 113	$ 271	$ 401
Average long-term borrowings	$ 11,167	$ 10,044	$ 8,224

Interest expense, excluding unrealized (gains) losses on interest rate derivatives was $0.22 per mcfe in 2009 compared to $0.22 per mcfe in 2008 and $0.50 per mcfe in 2007. The decrease in interest expense per mcfe for 2009 and 2008 is due to increased production volumes and an increase in capitalized interest. Capitalized interest increased in 2009 and 2008 as a result of a significant increase in unevaluated properties, the base on which interest is capitalized. We expect interest expense for 2010 to be between $0.30 and $0.35 per mcfe produced (before considering the effect of interest rate derivatives).

Impairment of Investments. We recorded a $162 million and $180 million impairment of certain investments in 2009 and 2008, respectively. Each of our investees has been impacted by the dramatic slowing of the worldwide economy and the freezing of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness has resulted in significantly reduced natural gas and oil prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized that an other than temporary impairment had occurred on the following investments in 2009: Gastar Exploration, Ltd., $70 million; Chaparral Energy, Inc., $51 million; DHS Drilling Company, $19 million; Ventura Refining, Transmission LLC, Inc., $13 million; and Mountain Drilling Company, $9 million. We recognized that an other than temporary impairment had occurred on the following investments in 2008: Chaparral Energy, Inc., $100 million; DHS Drilling Company, $20 million; Mountain Drilling Company, $10 million; and Ventura Refining and Transmission LLC, Inc., $50 million.

Loss on Exchanges or Repurchases of Chesapeake Debt. During 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 redeem this debt for common stock valued at less than 75% of the face value of the notes. Associated with these exchanges, we recorded a loss of $40 million. In connection with accounting guidance for debt with conversion and other options, we are required to account for the liability and equity components of our convertible debt instruments separately. 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 the value of the common stock exchanged in these transactions resulted in a $35 million loss. In addition, we expensed $5 million in deferred charges associated with these exchanges.

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

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

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

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $3.483 billion in 2009 compared to income tax expense of $387 million in 2008 and $892 million in 2007. Of the income tax benefit recorded in 2009, $4 million is reflected as current income tax expense and $3.487 billion is reflected as a deferred income tax benefit. Of the $3.870 billion decrease in 2009, $4.009 billion was the result of the decrease in net income before taxes which was offset by $139 million as the result of a decrease in the effective tax rate. Our effective income tax rate was 37.5% in 2009 compared to 39% in 2008 and 38% in 2007. 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 38.5% in 2010.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $0, $67 million and $128 million in 2009, 2008 and 2007, respectively. The loss on the exchanges represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms. See Note 8 of notes to the consolidated financial statements in Item 8 for further detail regarding these transactions.

Application of Critical Accounting Policies

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

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

Table of Contents

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

Accounting guidance for derivatives and hedging establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness is recognized immediately in natural gas and oil sales. For derivative instruments designated as fair value hedges, changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. 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.

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

Due to the volatility of natural gas and oil prices and, to a lesser extent, interest rates and foreign exchange rates, the company s financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2009, 2008 and 2007, the fair value of our derivatives was a liability of $63 million, an asset of $1.166 billion and a liability of $375 million, respectively. The derivatives that we acquired in our CNR acquisition represented $17 million and $184 million of liability at December 31, 2008 and 2007.

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

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

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

We review the carrying value of our natural gas and oil properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. For 2009, capitalized costs of natural gas and oil properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in a write-down in the carrying value of natural gas and oil properties of $6.9 billion, net of tax. In calculating future net revenues, effective December 31, 2009, current prices are calculated as the average natural gas and oil prices during the preceding 12-month period prior to the end of the current reporting period, determined as the unweighted arithmetical average of prices on the first day of each month within the 12-month period and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Based on the average prices for natural gas and oil during the 12-months of 2009, these cash flow hedges increased the full-cost ceiling by $1.1 billion, thereby reducing the ceiling test write-down by the same amount.

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.

In December 2008, the SEC issued its final rule for *Modernization of Oil and Gas Reporting*. Pursuant to this rule the SEC adopted revisions to its oil and gas reporting disclosures effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves, which should help investors evaluate the relative value of oil and gas companies. In the three decades that have passed since the original adoption of oil and gas disclosure items, there have been significant changes in the oil and gas industry. These revisions are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. The new rules include provisions that permit the use of new technologies to determine proved reserves. The requirements also require companies to report the independence and qualifications of the technical person(s) primarily responsible for the preparation or audit of reserve estimations and to file reports when a third party is relied upon to prepare or audit reserve estimates. In addition, the new rules require that oil and gas reserves be reported and the full-cost ceiling value calculated using average first-of-the-month natural gas and oil prices during the 12-month period ending in the reporting period, compared to prices at period end under prior SEC rules. It is not practicable for Chesapeake to estimate the effect of adopting the new reserve rules; however, these revisions and requirements affect the comparability between reporting periods for reserve volume and value estimates, full-cost pool write-down calculations and the calculation of depreciation, depletion and amortization of oil and gas assets.

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

As of December 31, 2008, Chesapeake had proved reserves of 12.051 tcfe at NYMEX spot prices of $5.71 per mcf and $44.61 per barrel before price differential adjustments. As of December 31, 2009, we had proved reserves of 14.254 tcfe at 2009 12-month average prices of $3.87 per mcf and $61.14 per barrel before price differential adjustments. The increase in proved reserves is, in part, due to the new reserve rules in effect for this filing.

Our December 31, 2008 proved undeveloped (PUD) reserve volume was 3.960 tcfe and our December 31, 2009 PUD reserve volume was 5.923 tcfe. This increase is partially attributable to the modernized rules, which allow for the reporting of PUD reserves more than one direct spacing area offsetting producing wells if reasonable certainty can be shown using reliable technology. Chesapeake has utilized and developed reliable geologic and engineering technology to book PUD reserves more than one location offsetting production in the Barnett Shale and Fayetteville Shale.

Within the Barnett and Fayetteville Shale plays, we used both public and proprietary geologic data to establish continuity of the formation and its producing properties. This included seismic data and interpretations (2-D, 3-D and micro seismic); open hole log information (both vertical and horizontally collected) and petrophysical analysis of the log data; mud logs; gas sample analysis; drill cutting samples; measurements of total organic content; thermal maturity; sidewall cores; whole cores and data measured from internal core analysis facility. Once the continuous geologic area was established, statistical analysis of established producing wells was used to generate reasonable certainty (defined as 90% probability aggregated to the field level). The analysis required a statistically significant number of producing wells within the defined geologic area and then tested for confidence by insuring the variance in results over time, area and distance was evaluated. Proper development spacing was also statistically analyzed.

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 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, 2009, we had deferred tax assets of $934 million.

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.

Table of Contents

Disclosures About Effects of Transactions with Related Parties

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

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

As disclosed in Note 17, in 2007, Chesapeake had revenues of $1.1 billion from natural gas and oil sales to Eagle Energy Partners I, L.P., a former affiliated entity. We sold our 33% limited partnership interest in Eagle Energy in June 2007.

Recently Issued Accounting Standards

In June 2009, the FASB issued amendments to the consolidation standard applicable to variable interest entities in response to concerns about the transparency of involvement with variable interest entities. The amended standard is effective for calendar year companies beginning on January 1, 2010. Beginning January 1, 2010, we will deconsolidate our joint venture with GIP and account for the investment in the joint venture under the equity method going forward. Adoption of this guidance will result in a cumulative effect adjustment for the difference in our equity in the joint venture at January 1, 2010, which was originally recorded at carryover basis, and the fair value of our equity at the formation of the joint venture based on the then fair value. This cumulative effect adjustment will create a basis difference between our equity investment balance and the underlying equity in the net assets of the joint venture. This difference will be accreted through earnings over the expected useful life of the underlying assets held by the joint venture.

In January 2010, the FASB updated its oil and gas estimation and disclosure requirements to align its requirements with the SEC s modernized oil and gas reporting rules, which are described above under *Application of Critical Accounting Policies*. The update amends the definition of proved reserves to use the average of first-day-of-the-month prices during the 12 months preceding the end of the reporting period, adds definitions used in estimating and disclosing proved oil and natural gas quantities and expands the disclosures required for equity-method investments. The update must be

Table of Contents

applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009. See Note 10 of the notes to our consolidated financial statements for disclosures regarding our natural gas and oil reserves.

Forward-Looking Statements

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

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

- the volatility of natural gas and oil prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- declines in the values of our natural gas and oil properties resulting in ceiling test write-downs;
- the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the timing of development expenditures;
- potential differences in our interpretations of new reserve disclosure rules and future SEC guidance;
- inability to generate profits or achieve targeted results in our development and exploratory drilling and well operations;
- leasehold terms expiring before production can be established;
- hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities;

a reduced ability to borrow or raise additional capital as a result of lower natural gas and oil prices;

drilling and operating risks, including potential environmental liabilities;

legislation and regulation adversely affecting our industry and our business;

general economic conditions negatively impacting us and our business counterparties;

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

losses possible from pending or future litigation.

Table of Contents

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

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

Natural Gas and Oil Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective natural gas and oil prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

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

Throughout 2008 and 2009, we restructured many of our trades that included knockout features as commodity prices decreased. The knockouts were typically restructured into straight swaps or collars based on strip prices at the time of the restructure. Additionally, in the latter half of 2009 we took advantage of attractive strip prices in 2012 through 2014 and sold natural gas and oil call options to our counterparties in exchange for 2010 and 2011 natural gas swaps with strike prices above the then current market price. This effectively allowed us to sell out-year volatility through call options at terms acceptable to us in exchange for straight natural gas swaps with strike prices well in excess of the then current market price for natural gas.

We use a wide range of derivative instruments to achieve our risk management objectives, including swaps, various collar arrangements and options (puts or calls). All of these are described in more detail below. We typically use swaps or collars for a large portion of the natural gas and oil volume we hedge. Swaps are used when the price level is acceptable and collars are used when the downside protection from the bought put is meaningful and the cap on upside from the sold call is at a satisfactory level. We also sell calls, taking advantage of market volatility for a portion of our projected production volumes when the strike price levels and the premiums are attractive to us. Typically, we sell call options when we would be satisfied to sell our production at the price being capped by the call strike or believe it to be more likely than not that the future natural gas or oil price will stay below the call strike price plus the premium we will receive.

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

Hedging positions, including swaps and collars, are adjusted in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our hedging positions continuously and if future market conditions change and prices have fallen to levels we believe could jeopardize the effectiveness of a position, we will mitigate such risk by either doing a cash settlement with our counterparty, restructuring the position, or by entering into a new swap that effectively reverses the current position (a counter-swap). The factors we consider in closing or restructuring a position before the settlement date are identical to those we reviewed when deciding to enter into the original hedge position.

As of December 31, 2009, our natural gas and oil derivative instruments were comprised of the following:

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

Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike price, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the collar. This eliminates the counterparty s downside exposure below the second put option.

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. If the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall. If the market price settles above the fixed price of the put option, no payment is due from either party.

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

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

In accordance with accounting guidance for hedging and derivatives, 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. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case, all cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows.

Table of Contents

As of December 31, 2009, we had the following open natural gas and oil derivative instruments designed to hedge a portion of our natural gas and oil production for periods after December 31, 2009:

	Volume (bbtu)	Fixed	Weighted Average Price Put (per mmbtu)	Call	Differential	Cash Flow Hedge	Net Premiums ($ in millions)	Fair Value
Natural Gas:								
Swaps:								
Q1 2010	63,478	$ 7.59	$	$	$	Yes	$	$ 124
Q2 2010	64,781	7.27				Yes		111
Q3 2010	51,972	7.32				Yes		81
Q4 2010	53,212	7.40				Yes		62
2011	22,210	7.99				Yes		36
Other Swaps[a] :								
Q1 2010	33,890	7.22				No		54
Q2 2010	43,680	7.61				No		59
Q3 2010	44,160	7.69				No		57
Q4 2010	44,160	8.04				No		51
2011	70,510	9.52				No		27
Collars:								
Q1 2010	29,700		6.24	8.06		Yes		19
Q2 2010	7,280		7.00	8.25		Yes		11
Other Collars[b] :								
Q1 2010	13,500		4.29/7.05	9.49		No		19
Q2 2010	9,100		4.35/7.07	9.91		No	5	15
Q3 2010	3,680		7.60	11.75		No	4	8
Q4 2010	3,680		7.60	11.75		No	4	7
2011	7,300		7.60	11.50		No	7	13
Knockout Swaps:								
Q3 2010	7,360	9.79	6.32			No		4
Q4 2010	7,360	9.79	6.31			No		3
2011	23,650	9.86	6.29			No		10
Call Options:								
Q1 2010	18,585			10.19		No	41	
Q2 2010	28,665			10.19		No	41	(1)
Q3 2010	34,040			10.22		No	43	(3)
Q4 2010	34,040			10.30		No	43	(6)
2011	20,987			10.73		No	42	(4)
2012	262,605			8.46		No	16	(150)
2013 2020	597,828			9.10		No	102	(377)
Put Options:								
Q3 2010	(16,560)		5.73			No	6	(12)
Q4 2010	(16,560)		5.73			No	6	(12)
2011	(36,500)		5.75			No	25	(26)
Basis Protection Swaps (Non-Appalachian Basin):								
2011	45,090				(0.82)	No	(3)	(22)
2012 2018	57,961				(0.90)	No	(3)	(29)
Basis Protection Swaps (Appalachian Basin):								

Q1 2010	2,293	0.27	No		
Q2 2010	2,513	0.27	No		
Q3 2010	2,660	0.26	No		
Q4 2010	2,732	0.26	No		
2011	12,086	0.25	No		1
2012 2022	134	0.11	No		
Total Natural Gas				379	130

70

Table of Contents

	Volume (mbbls)	Weighted Average Price Fixed (per bbl)	Put	Call	Differential	Cash Flow Hedge	Net Premiums ($ in millions)	Fair Value
Oil:								
Swaps:								
Q1 2010	450	$ 85.86	$	$	$	Yes	$	$ 3
Q2 2010	455	85.86				Yes		2
Q3 2010	460	85.86				Yes		1
Q4 2010	460	85.86				Yes		1
Other Swaps[c] :								
Q1 2010	360	91.96				No		4
Q2 2010	364	91.96				No		4
Q3 2010	368	91.96				No		3
Q4 2010	368	91.96				No		3
2011	2,190	91.76				No		(18)
Knock-Out Swaps:								
Q1 2010	1,170	90.25	60.00			No		12
Q2 2010	1,183	90.25	60.00			No		7
Q3 2010	1,196	90.25	60.00			No		3
Q4 2010	1,196	90.25	60.00			No		(1)
2011	1,095	104.75	60.00			No		7
2012	732	109.50	60.00			No		4
Call Options:								
Q1 2010	630			105.00		No	(1)	
Q2 2010	637			105.00		No	(1)	(1)
Q3 2010	644			105.00		No	(1)	(2)
Q4 2010	644			105.00		No	(1)	(3)
2011	3,650			105.00		No	16	(25)
2012 2014	8,770			99.59		No	16	(113)
Total Oil							28	(109)
Total Natural Gas and Oil							$ 407	$ 21

(a) Included in Other Swaps are options to extend existing swaps for an additional 12 months. The volume of such extendables in 2010 is 27,500 bbtu at a weighted average fixed swap price of $9.03/mmbtu, and in 2011 is 51,950 bbtu at an average fixed price of $10.05/mmbtu.

(b) Included in Other Collars for 2010 are 11,740 bbtu of three-way collars which have written put options with weighted average prices of $4.31/mmbtu, which limits the counterparty s exposure.

(c) Included in Other Swaps are options to extend existing swaps for an additional 12 months. The volume of such extendables in 2011 is 2,190 mbbl at a weighted average fixed price of $91.76/bbl.

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 mitigated under our new 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.

Table of Contents

The table below reconciles the years ended December 31, 2009, 2008 and 2007 changes in fair value of our natural gas and oil derivatives. Of the $21 million fair value asset as of December 31, 2009, $686 million relates to contracts maturing in the next 12 months, of which we expect to transfer approximately $202 million (net of income taxes) from accumulated other comprehensive income to net income (loss), and ($665) million relates to contracts maturing after 12 months. All transactions hedged as of December 31, 2009 are expected to mature by December 31, 2022.

	2009	2008	2007
		($ in millions)	
Fair value of contracts outstanding, as of January 1	$ 1,305	$ (369)	$ 345
Change in fair value of contracts	1,266	1,880	972
Fair value of contracts when entered into	(21)	(569)	(295)
Contracts realized or otherwise settled	(2,102)	9	(1,203)
Fair value of contracts when closed	(427)	354	(188)
Fair value of contracts outstanding, as of December 31	$ 21	$ 1,305	$ (369)

The change in natural gas and oil prices during the year ended December 31, 2009 increased the value of our derivative assets by $1.3 billion. This gain is recorded in natural gas and oil sales or in accumulated other comprehensive income. We entered into new contracts which had premiums of $21 million, and a liability was recorded. We settled and closed out contracts, reducing our assets by $2.1 billion and $427 million, respectively, and 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). Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within natural gas and oil sales. Realized gains (losses) are included in natural gas and oil sales in the month of related production.

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

Table of Contents

The components of natural gas and oil sales for the years ended December 31, 2009, 2008 and 2007 are presented below.

	Years Ended December 31,		
	2009	2008	2007
		($ in millions)	
Natural gas and oil sales	$ 3,291	$ 7,069	$ 4,795
Realized gains (losses) on natural gas and oil derivatives	2,346	(8)	1,203
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(624)	887	(252)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	36	(90)	(122)
Total natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624

To mitigate our exposure to the fluctuation in price of diesel fuel which is used in our exploration and development activities, we have entered into diesel swaps from January 2010 to March 2010 for a total of 10.4 million gallons with an average fixed price of $1.58 per gallon. Chesapeake pays the fixed price and receives the floating price. The fair value of these swaps as of December 31, 2009 was an asset of $5 million.

Interest Rate Risk

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

	Years of Maturity						
	2010	2011	2012	2013	2014	Thereafter	Total
				($ in millions)			
Liabilities:							
Long-term debt fixed rate[a]	$	$	$	$ 864	$ 600	$ 9,747	$ 11,211
Average interest rate				7.6%	7.3%	6.0%	6.2%
Long-term debt variable rate	$	$	$ 1,936	$	$	$	$ 1,936
Average interest rate			2.2%				2.2%

(a) This amount does not include the discount included in long-term debt of ($921) million and interest rate derivatives of $69 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 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, 2009, 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 a pay fixed interest rate) to manage our interest rate exposure related to our bank credit facility borrowings.

Table of Contents

Collars: These instruments contain a fixed floor rate (floor) and a ceiling rate (cap). If the floating rate is above the cap, we have a net receivable from the counterparty and if the floating rate is below the floor, we have a net payable to the counterparty. If the floating rate is between the floor and the cap, there is no payment due from either party. Collars are used 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 an open swap at a specific date.

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, 2009, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Rate Fixed	Floating[b]	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value
Fixed to Floating:						
Swaps						
Mature 2015	$ 550	9.50%	1 3 mL plus 657 bp	Yes	$	$ (11)
Mature 2013 2020	$ 1,000	7.06%	3 6 mL plus 417 bp	No	9	(61)
Call Options						
Expire May 2010	$ 250	6.88%	3 mL plus 287 bp	No	4	(2)
Swaption						
Expire June 2010	$ 500	6.88%	3 mL plus 254 bp	No	5	(11)
Floating to Fixed:						
Swaps						
Mature 2010 2012	$ 1,375	3.30%	1 6 mL	No		(41)
Collars[a]						
Mature 2010	$ 250	4.52%	6 mL	No		(6)
					$ 18	$ (132)

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

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

In 2009, we closed interest rate derivatives for gains totaling $49 million of which $23 million was recognized in interest expense. The remaining $26 million was from interest rate derivatives designated as fair value hedges which are accounted for as a reduction to our senior notes. The settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes ranging from four to eleven years.

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. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized (gains) losses within interest expense.

Table of Contents

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, 2009, 2008 and 2007 are presented below.

	Years Ended December 31,		
	2009	2008	2007
		($ in millions)	
Interest expense on senior notes	$ 765	$ 637	$ 538
Interest expense on credit facilities	60	117	113
Capitalized interest	(633)	(585)	(311)
Realized (gains) losses on interest rate derivatives	(23)	(6)	1
Unrealized (gains) losses on interest rate derivatives	(91)	85	40
Amortization of loan discount and other	35	23	20
Total interest expense	$ 113	$ 271	$ 401

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake 19 million and Chesapeake pays the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge. The fair value of the cross currency swap is recorded on the consolidated balance sheet as an asset of $43 million at December 31, 2009. The euro-denominated debt in notes payable has been adjusted to $860 million at December 31, 2009 using an exchange rate of $1.4332 to 1.00.

Table of Contents

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

INDEX TO FINANCIAL STATEMENTS

CHESAPEAKE ENERGY CORPORATION

Table of Contents

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, 2009.

The effectiveness of the company s internal control over financial reporting as of December 31, 2009 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/ MARCUS C. ROWLAND
Marcus C. Rowland
Executive Vice President and Chief Financial Officer

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 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, 2009, 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 20 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. Also as discussed in Note 3 to the consolidated financial statements, the Company changed the manner in which it accounts for contingent convertible debt instruments as of January 1, 2009, and retrospectively applied the impact to prior periods.

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

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

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP

Tulsa, Oklahoma

March 1, 2010

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 307	$ 1,749
Accounts receivable	1,325	1,324
Short-term derivative instruments	692	1,082
Deferred income tax asset	24	
Inventory	25	58
Other	73	79
Total Current Assets	2,446	4,292
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	35,007	28,965
Unevaluated properties	10,005	11,379
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(24,220)	(11,866)
Total natural gas and oil properties, at cost based on full-cost accounting	20,792	28,478
Other property and equipment:		
Natural gas gathering systems and treating plants	3,516	2,717
Buildings and land	1,673	1,513
Drilling rigs and equipment	687	430
Natural gas compressors	325	184
Other	550	482
Less: accumulated depreciation and amortization of other property and equipment	(833)	(496)
Total Other Property and Equipment	5,918	4,830
Total Property and Equipment	26,710	33,308
OTHER ASSETS:		
Investments	404	444
Long-term derivative instruments	60	261
Other assets	294	288
Total Other Assets	758	993
TOTAL ASSETS	$ 29,914	$ 38,593

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	December 31, 2009	December 31, 2008
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 957	$ 1,611
Short-term derivative instruments	27	66
Accrued liabilities	920	880
Deferred income taxes		358
Income taxes payable	1	108
Revenues and royalties due others	565	431
Accrued interest	218	167
Total Current Liabilities	2,688	3,621
LONG-TERM LIABILITIES:		
Long-term debt, net	12,295	13,175
Deferred income tax liabilities	1,059	4,200
Asset retirement obligations	282	269
Long-term derivative instruments	787	111
Revenues and royalties due others	73	49
Other liabilities	389	151
Total Long-Term Liabilities	14,885	17,955
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake stockholders equity:		
Preferred Stock, $0.01 par value, 20,000,000 shares authorized:		
4.50% cumulative convertible preferred stock 2,558,900 shares issued and outstanding as of December 31, 2009 and 2008, respectively, entitled in liquidation to $256 million	256	256
5.00% cumulative convertible preferred stock (series 2005B) 2,095,615 shares issued and outstanding as of December 31, 2009 and 2008, respectively, entitled in liquidation to $209 million	209	209
5.00% cumulative convertible preferred stock (series 2005), 5,000 shares issued and outstanding as of December 31, 2009 and 2008, entitled in liquidation to $1 million	1	1
6.25% mandatory convertible preferred stock, 0 and 143,768 shares issued and outstanding as of December 31, 2009 and 2008, entitled in liquidation to $0 and $36 million		36
4.125% cumulative convertible preferred stock, 0 and 3,033 shares issued and outstanding as of December 31, 2009 and 2008, respectively, entitled in liquidation to $0 and $3 million		3
Common stock, $0.01 par value, 1,000,000,000 and 750,000,000 shares authorized, 648,549,165 and 607,953,437 shares issued December 31, 2009 and 2008, respectively	6	6
Paid-in capital	12,146	11,680
Retained earnings (deficit)	(1,261)	4,569
Accumulated other comprehensive income (loss), net of tax of ($62) million and ($163) million, respectively	102	267
Less: treasury stock, at cost; 877,205 and 657,276 common shares as of December 31, 2009 and 2008, respectively	(15)	(10)
Total Chesapeake Stockholders Equity	11,444	17,017
Noncontrolling interest	897	
Total Equity	12,341	17,017

TOTAL LIABILITIES AND EQUITY	$ 29,914	$ 38,593

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATION

	Years Ended December 31,		
	2009	2008	2007
	($ in millions, except per share data)		
REVENUES:			
Natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624
Marketing, gathering and compression sales	2,463	3,598	2,040
Service operations revenue	190	173	136
Total Revenues	7,702	11,629	7,800
OPERATING COSTS:			
Production expenses	876	889	640
Production taxes	107	284	216
General and administrative expenses	349	377	243
Marketing, gathering and compression expenses	2,316	3,505	1,969
Service operations expense	182	143	94
Natural gas and oil depreciation, depletion and amortization	1,371	1,970	1,835
Depreciation and amortization of other assets	244	174	153
Impairment of natural gas and oil properties and other assets	11,130	2,830	
Loss on sale of other property and equipment	38		
Restructuring costs	34		
Total Operating Costs	16,647	10,172	5,150
INCOME (LOSS) FROM OPERATIONS	(8,945)	1,457	2,650
OTHER INCOME (EXPENSE):			
Other income (expense)	(28)	(11)	15
Interest expense	(113)	(271)	(401)
Impairment of investments	(162)	(180)	
Loss on exchanges or repurchases of Chesapeake debt	(40)	(4)	
Gain on sale of investments			83
Total Other Income (Expense)	(343)	(466)	(303)
INCOME (LOSS) BEFORE INCOME TAXES	(9,288)	991	2,347
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	4	423	29
Deferred income taxes	(3,487)	(36)	863
Total Income Tax Expense (Benefit)	(3,483)	387	892
NET INCOME(LOSS)	(5,805)	604	1,455
Net (income) attributable to noncontrolling interest	(25)		
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(5,830)	604	1,455
Preferred stock dividends	(23)	(33)	(94)
Loss on conversion/exchange of preferred stock		(67)	(128)

NET INCOME (LOSS) AVAILABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$ (5,853)	$ 504	$ 1,233
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ (9.57)	$ 0.94	$ 2.70
Assuming dilution	$ (9.57)	$ 0.93	$ 2.63
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.30	$ 0.2925	$ 0.2625
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	612	536	456
Assuming dilution	612	545	487

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2009	**2008** ($ in millions)	**2007**
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ (5,805)	$ 604	$ 1,455
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	1,615	2,144	1,988
Deferred income tax expense (benefit)	(3,487)	(36)	863
Unrealized (gains) losses on derivatives	497	(712)	415
Realized (gains) losses on financing derivatives	(154)	38	(92)
Stock-based compensation	140	132	84
Accretion of discount on contingent convertible notes	79	79	37
Restructuring costs	12		
Loss on sale of other property and equipment	38		
Gain on sale of investments			(83)
Loss from equity investments	39	38	
Loss repurchases or exchanges of Chesapeake debt	40	4	
Impairment of natural gas and oil properties and other fixed assets	11,130	2,830	
Impairment of investments	162	180	
Other	27	(2)	8
(Increase) decrease in accounts receivable		(78)	(192)
(Increase) decrease in inventory and other assets	(31)	56	(65)
Increase (decrease) in accounts payable, accrued liabilities and other	(105)	76	430
Increase (decrease) in current and non-current revenues and royalties due others	159	4	126
Cash provided by operating activities	4,356	5,357	4,974
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of natural gas and oil companies, proved and unproved properties, net of cash acquired	(2,298)	(8,593)	(3,003)
Exploration and development of natural gas and oil properties	(3,543)	(6,104)	(5,305)
Additions to other property and equipment	(1,683)	(3,073)	(1,439)
Additions to investments	(40)	(74)	(8)
Proceeds from divestitures of proved and unproved properties and leasehold	1,518	6,091	
Proceeds from sale of volumetric production payments	408	1,579	1,089
Proceeds from sale of compressors	68	114	188
Proceeds from sale of drilling rigs and equipment		64	369
Proceeds from sale of investments		2	124
Deposits for acquisitions		(12)	(15)
Proceeds from sale of other assets and other	108	41	36
Cash used in investing activities	(5,462)	(9,965)	(7,964)

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from credit facilities borrowings	7,761	13,291	7,932
Payments on credit facilities borrowings	(9,758)	(11,307)	(6,160)
Proceeds from issuance of senior notes, net of offering costs	1,346	2,136	1,607
Proceeds from issuance of common stock, net of offering costs		2,598	
Cash paid to purchase Chesapeake senior notes		(312)	
Cash paid for common stock dividends	(181)	(148)	(115)
Cash paid for preferred stock dividends	(23)	(35)	(95)
Cash paid for treasury stock	(7)	(5)	
Proceeds from sale of noncontrolling interest in midstream joint venture	588		
Distribution to midstream joint venture partner	(10)		
Midstream joint venture transaction costs	(16)		
Derivative settlements	109	(167)	(91)
Net increase (decrease) in outstanding payments in excess of cash balance	(249)	330	(98)
Proceeds from mortgage of building	54		
Proceeds from financing of real estate surface assets	145		
Cash received from exercise of stock options	4	9	15
Excess tax benefit from stock-based compensation		43	20
Other	(99)	(77)	(27)
Cash provided (used in) by financing activities	(336)	6,356	2,988
Net increase (decrease) in cash and cash equivalents	(1,442)	1,748	(2)
Cash and cash equivalents, beginning of period	1,749	1	3
Cash and cash equivalents, end of period	$ 307	$ 1,749	$ 1
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$ 64	$ 97	$ 273
Income taxes, net of refunds received	$ 7	$ 296	$ 55

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of December 31, 2009, 2008 and 2007, dividends payable on our common and preferred stock were $53 million, $50 million and $53 million, respectively.

In 2009, 2008 and 2007, natural gas and oil properties were adjusted by a nominal amount, $13 million and $131 million, respectively, for net income tax liabilities related to acquisitions.

During 2009, 2008 and 2007, natural gas and oil properties were adjusted by ($93) million, ($4) million and $97 million, respectively, as a result of an increase (decrease) in accrued acquisition, exploration and development costs.

During 2009, 2008 and 2007, other property and equipment were adjusted by ($53) million, $125 million and $3 million, respectively, as a result in an increase (decrease) in accrued costs.

We recorded non-cash asset additions (reductions) to net natural gas and oil properties of ($2) million, $10 million and $29 million in 2009, 2008 and 2007, respectively, for asset retirement obligations.

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

In 2009 and 2008, holders of certain of our contingent convertible senior notes exchanged or converted their senior notes for shares of common stock in privately negotiated exchanges as summarized below ($ in millions):

Year	Contingent Convertible Senior Notes	Principal Amount	Number of Common Shares
2009	2.25% due 2038	$ 364	10,210,169
2008	2.75% due 2035	$ 239	8,841,526
2008	2.50% due 2037	272	8,416,865
2008	2.25% due 2038	254	6,654,821
		$ 765	23,913,212

In 2009 and 2008, we issued 24,822,832 and 1,677,000 shares of common stock, valued at $421 million and $34 million, respectively, for the purchase of leasehold and unproved properties pursuant to an acquisition shelf registration statement.

In 2009, 2008 and 2007, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/ Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares	Type of Transaction
2009	6.25%	143,768	1,239,538	Conversion
	4.125%	3,033	182,887	Conversion
			1,422,425	
2008	5.0% (series 2005B)	3,654,385	10,443,642	Exchange
	4.5%	891,100	2,227,750	Exchange
	4.125%	29	1,743	Conversion
			12,673,135	
2007	5.0% (series 2005)	4,595,000	19,283,311	Exchange
	6.25%	2,156,184	17,367,823	Exchange
	6.25%	48	344	Conversion
	4.125%	3	180	Conversion
			36,651,658	

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 505	$ 960	$ 1,958
Exchange of common stock for 0, 3,654,385 and 0 shares of 5.00% preferred stock (series 2005B)		(366)	
Exchange of common stock for 0, 891,000 and 0 shares of 4.50% preferred stock		(89)	
Exchange of common stock for 0, 0 and 4,595,000 shares of 5.00% preferred stock (series 2005)			(459)
Exchange of common stock for 143,768, 0 and 2,156,232 shares of 6.25% preferred stock	(36)		(539)
Exchange of common stock for 3,033, 29 and 3 shares of 4.125% preferred stock	(3)		
Balance, end of period	466	505	960
COMMON STOCK:			
Balance, beginning of period	6	5	5
Issuance of 0, 51,750,000 and 0 shares of common stock		1	
Issuance of 24,822,832, 1,677,000 and 0 shares of common stock for the purchase of leasehold and unproved properties			
Exchange of 1,422,425, 12,673,135 and 36,651,658 shares of common stock for preferred stock			
Exchange of 10,210,169, 23,913,212 and 0 shares of common stock for convertible notes			
Balance, end of period	6	6	5
PAID-IN CAPITAL:			
Balance, beginning of period	11,680	7,532	5,998
Issuance of 0, 51,750,000 and 0 shares of common stock		2,697	
Issuance of 24,822,832, 1,677,000 and 0 shares of common stock for the purchase of leasehold and unproved properties	421	34	
Issuance of 2.50% contingent convertible senior notes due 2037			375
Issuance of 2.25% contingent convertible senior notes due 2038		345	
Exchange of 10,210,169, 23,913,212 and 0 shares of common stock for convertible notes	262	480	
Exchange of 1,422,425, 12,673,135 and 36,651,658 shares of common stock for preferred stock	39	454	998
Stock-based compensation	199	188	129
Offering/transaction expenses	(16)	(101)	
Dividends on common stock	(185)		
Dividends on preferred stock	(22)		
Exercise of stock options	4	8	15
Equalization of partners capital accounts	(294)		
Tax effect on equalization of partners capital	106		
Tax benefit (reduction in tax benefit) from exercise of stock options and restricted stock	(48)	43	20
Preferred stock conversion/exchange expenses			(3)
Balance, end of period	12,146	11,680	7,532

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

85

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY (Continued)

	Years Ended December 31, 2009	2008	2007
	($ in millions)		
RETAINED EARNINGS (DEFICIT):			
Balance, beginning of period	$ 4,569	$ 4,144	$ 2,903
Net income (loss) attributable to Chesapeake	(5,830)	604	1,455
Dividends on common stock		(158)	(121)
Dividends on preferred stock		(21)	(89)
Other			(4)
Balance, end of period	(1,261)	4,569	4,144
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	267	(11)	528
Hedging activity	(231)	297	(520)
Investment activity	66	(19)	(19)
Balance, end of period	102	267	(11)
TREASURY STOCK COMMON:			
Balance, beginning of period	(10)	(6)	(26)
Purchase of 227,827, 159,430 and 0 shares of treasury stock	(5)	(4)	
Release of 7,898, 2,975 and 666,186 shares for company benefit plans			20
Balance, end of period	(15)	(10)	(6)
TOTAL CHESAPEAKE STOCKHOLDERS EQUITY	11,444	17,017	12,624
NONCONTROLLING INTEREST:			
Balance, beginning of period			
Sale of noncontrolling interest in midstream joint venture	588		
Equalization of partners capital accounts	294		
Distribution to partner	(10)		
Chesapeake Midstream Partners net income attributable to Global Infrastructure Partners	25		
Balance, end of period	897		
TOTAL EQUITY	$ 12,341	$ 17,017	$ 12,624

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Net income (loss)	$ (5,805)	$ 604	$ 1,455
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of $413 million, $113 million and ($56) million, respectively	677	186	(92)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($540) million, $35 million and ($308) million, respectively	(885)	55	(504)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($14) million, $34 million and $46 million, respectively	(23)	56	76
Unrealized (gain) loss on marketable securities, net of income taxes of $14 million, ($12) million and ($11) million, respectively	23	(19)	(19)
Reclassification of loss on investments, net of income taxes of $26 million, $0 and $0, respectively	43		
Comprehensive income (loss)	(5,970)	882	916
(Income) attributable to noncontrolling interest	(25)		
Comprehensive income (loss) available to Chesapeake	$ (5,995)	$ 882	$ 916

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

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

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake include the accounts of our direct and indirect wholly-owned subsidiaries, as well as our 50/50 joint venture with Global Infrastructure Partners (GIP). Because of certain commitments and contractual arrangements with GIP, the joint venture partnership qualifies as a variable interest entity and must be consolidated by the company, as the primary beneficiary. All significant intercompany accounts and transactions have been eliminated.

Change in Accounting Principle

On January 1, 2009, we adopted and applied retrospectively new accounting and reporting standards for debt with conversion and other options. As a result, our prior year consolidated financial statements have been retrospectively adjusted. See Note 3 for additional information on the application of this accounting principle.

Accounting Estimates

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

Cash Equivalents

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

Accounts Receivable

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounts receivable consists of the following components:

	December 31, 2009	December 31, 2008
	($ in millions)	
Natural gas and oil sales	$ 743	$ 738
Joint interest	394	424
Service operations	7	20
Related parties[(a)]	15	
Other	190	154
Allowance for doubtful accounts	(24)	(12)
Total accounts receivable	$ 1,325	$ 1,324

(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 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, 2009 were prepared by both third party engineering firms and Chesapeake s internal staff. Approximately 83% of these proved reserves estimates (by volume) at year-end 2009 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 were $1.51 per mcfe in 2009, $2.34 per mcfe in 2008 and $2.57 per mcfe in 2007.

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

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

We review the carrying value of our natural gas and oil properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In 2009, capitalized costs of natural gas and oil properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in a write-down in the carrying value of natural gas and oil properties of $6.9 billion, net of tax. In calculating future net revenues, effective December 31, 2009, current prices are calculated as the average natural gas and oil prices during the preceding 12-month period prior to the end of the current reporting period,

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

determined as the unweighted arithmetical average of prices on the first day of each month within the 12-month period and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Based on average prices for the prior 12-month period for natural gas and oil as of December 31, 2009, these cash flow hedges increased the full-cost ceiling by $1.1 billion, thereby reducing the ceiling test write-down by the same amount. Our qualifying cash flow hedges as of December 31, 2009, which consisted of swaps and collars, covered 281 bcfe and 22 bcfe in 2010 and 2011, respectively. Our natural gas and oil hedging activities are discussed in Note 9 of these consolidated financial statements.

Two primary factors impacting the ceiling test are reserve levels and 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.

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 and processing facilities, drilling rigs, land, buildings and improvements, natural gas compressors, 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 operations. Other property and equipment costs are depreciated on a straight-line basis. A summary of other property and equipment and the useful lives is as follows:

	December 31,		
	2009	2008	Useful Life
	($ in millions)		(in years)
Natural gas gathering systems and treating plants	$ 3,516	$ 2,717	20
Buildings and improvements	805	681	10 39
Drilling rigs and equipment	687	430	3 15
Natural gas compressors	325	184	20
Land	868	832	
Other	550	482	2 7
Total	$ 6,751	$ 5,326	

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2009, we recorded an impairment of $86 million associated with certain of our midstream assets and $27 million associated with certain of our service operations assets.

Investments

Investments in securities are accounted for under the equity method in circumstances where we are deemed to exercise significant influence over the operating and investing policies of the investee but do not have control. Under the equity method, we recognize our share of the investee s earnings in our consolidated statements of operations. Investments in securities not accounted for under the equity method are accounted for under the cost method. Investments in marketable equity securities accounted for under the cost method have been designated as available for sale and, as such, are recorded at fair value. We evaluate our investments for impairment in value and recognize a charge to earnings when any identified impairment is judged to be other than temporary. For 2009, we recorded an impairment of $162 million associated with certain of our investments. See Note 14 for further discussion of investments.

Capitalized Interest

During 2009, 2008 and 2007, interest of approximately $627 million, $585 million and $311 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. An additional $6 million was capitalized in 2009 on midstream assets which were under construction. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings.

Accounts Payable and Accrued Liabilities

Included in accounts payable at December 31, 2009 and 2008, respectively, are liabilities of approximately $231 million and $480 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Other accrued liabilities include $198 million and $258 million of accrued drilling costs as of December 31, 2009 and 2008, respectively.

Debt Issuance Costs

Included in other assets are costs associated with the issuance of our senior notes and costs associated with our revolving bank credit facilities and hedging facilities. The remaining unamortized debt issue costs at December 31, 2009 and 2008 totaled $162 million and $142 million, respectively, and are being amortized over the life of the senior notes, revolving credit facilities or hedging facilities.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 asset retirement obligation is capitalized as part of the carrying amount of our natural gas and oil properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is reversed.

Revenue Recognition

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

Natural Gas Imbalances. We follow the sales method of accounting for our natural gas revenue whereby we recognize sales revenue on all natural gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining natural gas reserves on the underlying properties. The natural gas imbalance net position at December 31, 2009 and 2008 was a liability of $7 million and $6 million, respectively.

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

Hedging

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

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

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 cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness 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 also recognized currently in earnings. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case, all 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 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 at grant date of those awards. For equity-based compensation awards granted or modified, compensation expense based on the fair value on the date of grant or modification is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. To the extent compensation cost relates to employees directly involved in natural gas and oil exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expenses, production expenses, marketing, gathering and compression expenses or service operations expense.

For the years ended December 31, 2009, 2008 and 2007, we recorded the following stock-based compensation ($ in millions):

	2009	2008	2007
Natural gas and oil properties	$ 112	$ 109	$ 68
General and administrative expenses	83	85	57
Production expenses	34	30	19
Marketing, gathering and compression expenses	16	11	5
Service operations expense	8	6	3
Total	$ 253	$ 241	$ 152

Cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock (excess tax benefits) are classified as financing cash inflows in our statements of cash flows. For the year ended December 31, 2009, we recognized a reduction in tax benefits related to stock-based compensation of $48 million which is reported in operating activities on our consolidated statements of cash flows. For the years ended December 31, 2008 and 2007, we recognized $43 million and $20 million, respectively, of excess tax benefits from stock-based compensation as cash provided by financing activities on our statements of cash flows.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2008 and 2007 to conform to the presentation used for the 2009 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, 2009, 2008 and 2007, the following securities and associated adjustments to net income comprised of dividends and loss on conversions/exchanges were not included in the calculation of diluted EPS, as the effect was antidilutive:

	Shares (in millions)	Net Income Adjustments ($ in millions)
Year Ended December 31, 2009:		
Common stock equivalent of our preferred stock outstanding:		
4.50% cumulative convertible preferred stock	6	$ 12
5.00% cumulative convertible preferred stock (series 2005)		$
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 10
Common stock equivalent of our preferred stock outstanding prior to conversion:		
6.25% mandatory convertible preferred stock	1	$ 1
4.125% cumulative convertible preferred stock		$
Year Ended December 31, 2008:		
Common stock equivalent of our preferred stock outstanding:		
4.50% cumulative convertible preferred stock	6	$ 12
5.00% cumulative convertible preferred stock (series 2005)		$
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 10
6.25% mandatory convertible preferred stock	1	$ 2
Common stock equivalent of our preferred stock outstanding prior to conversion:		
4.50% cumulative convertible preferred stock	1	$ 14
5.00% cumulative convertible preferred stock (series 2005B)	4	$ 62
Year Ended December 31, 2007:		
Common stock equivalent of our preferred stock outstanding prior to conversion:		
5.00% cumulative convertible preferred stock (series 2005)	16	$ 76
6.25% mandatory convertible preferred stock	14	$ 99

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 which are used in computing EPS assuming dilution were 612 million shares as a result of the net loss to common stockholders. The basic and diluted loss per common share was $9.57.

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

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
For the Year Ended December 31, 2008:			
Basic EPS:			
Income available to common stockholders	$ 504	536	$ 0.94
Effect of Dilutive Securities			
Effect of contingent convertible senior notes outstanding during the period		1	
Employee stock options		2	
Restricted stock		6	
Diluted EPS Income available to common stockholders and assumed conversions	$ 504	545	$ 0.93
For the Year Ended December 31, 2007:			
Basic EPS:			
Income available to common stockholders	$ 1,233	456	$ 2.70
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% convertible preferred stock (series 2005B)		15	
Common shares assumed issued for 6.25% mandatory convertible preferred stock		1	
Employee stock options		4	
Restricted stock		3	
Preferred stock dividends	47		
Diluted EPS income available to common stockholders and assumed conversions	$ 1,280	487	$ 2.63

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Senior Notes and Revolving Bank Credit Facilities

Our long-term debt consisted of the following at December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	($ in millions)	
7.5% senior notes due 2013	$ 364	$ 364
7.625% senior notes due 2013	500	500
7.0% senior notes due 2014	300	300
7.5% senior notes due 2014	300	300
6.375% senior notes due 2015	600	600
9.5% senior notes due 2015	1,425	
6.625% senior notes due 2016	600	600
6.875% senior notes due 2016	670	670
6.25% Euro-denominated senior notes due 2017[a]	860	835
6.5% senior notes due 2017	1,100	1,100
6.25% senior notes due 2018	600	600
7.25% senior notes due 2018	800	800
6.875% senior Notes due 2020	500	500
2.75% contingent convertible senior notes due 2035[b]	451	451
2.5% contingent convertible senior notes due 2037[b]	1,378	1,378
2.25% contingent convertible senior notes due 2038[b]	763	1,126
Corporate revolving bank credit facility	1,892	3,474
Midstream revolving bank credit facility		
Midstream joint venture revolving bank credit facility	44	460
Discount on senior notes[c]	(921)	(1,094)
Interest rate derivatives[d]	69	211
Total notes payable and long-term debt	$ 12,295	$ 13,175

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4332 to 1.00 and $1.3919 to 1.00 as of December 31, 2009 and 2008, respectively. See Note 10 for information on our related cross currency swap.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the fourth quarter of 2009, 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 2010 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds		Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$	48.81	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$	64.36	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$	107.36	June 14, 2019

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(c) Discount at December 31, 2008 is adjusted for the retrospective application of accounting guidance for debt with conversion and other options. Discount at December 31, 2009 and 2008 included $794 million and $1.009 billion, respectively, associated with the equity component of our contingent convertible senior notes.

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

Senior Notes

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

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. As of September 30, 2008, our obligations under our outstanding senior notes and contingent convertible notes were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned restricted subsidiaries, other than minor subsidiaries, on a senior unsecured basis. In October 2008, we restructured our midstream operations. As a result, beginning in the fourth quarter of 2008, our wholly-owned midstream subsidiaries having significant assets and operations do not guarantee our outstanding senior notes.

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

On January 1, 2009, we adopted and applied retrospectively new accounting and reporting standards for debt with conversion and other options. We have three debt issuances affected by this change: 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. These standards require us 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 (6.86%, 8.0% and 8.0%, respectively). Additionally, debt issuance costs are required to be allocated in proportion to the liability and equity components and accounted for as debt issuance costs and equity issuance costs, respectively. The allocation to the equity component of the convertible notes was $845 million (net of tax) at December 31, 2008. The accretion of the resulting discount on the debt is recognized as a part of interest expense, thereby increasing the amount of interest expense required to be recognized with respect to such instruments. Given the increase in our overall effective interest rate after adoption of these standards, we also capitalized additional interest which largely offset the increase in interest expense.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the effect of the change in accounting principle related to our contingent convertible notes on the consolidated balance sheet:

	December 31, 2008		
	Previously Reported	Adjustment	Adjusted
		($ in millions)	
Unevaluated properties	$ 11,216	$ 163	$ 11,379
Other long-term assets	$ 1,007	$ (14)	$ 993
Long-term debt, net	$ 14,184	$ (1,009)	$ 13,175
Deferred income tax liability	$ 3,763	$ 437	$ 4,200
Paid-in-capital	$ 10,835	$ 845	$ 11,680
Retained earnings	$ 4,694	$ (125)	$ 4,569

The following table summarizes the effect of the change in accounting principle related to our contingent convertible notes on the consolidated statements of operations ($ in millions, except per share data):

	Previously Reported	Adjustment	Adjusted
Year Ended December 31, 2008:			
Depreciation and amortization of other assets	$ 177	$ (3)	$ 174
Interest expense	$ 314	$ (43)	$ 271
Gain (loss) on exchanges or repurchases of Chesapeake debt	$ 237	$ (241)	$ (4)
Income tax expense	$ 463	$ (76)	$ 387
Net income	$ 723	$ (119)	$ 604
Weighted average common and common equivalent shares outstanding assuming dilution (in millions)	545		545
Earnings per common share:			
Basic	$ 1.16	$ (0.22)	$ 0.94
Diluted	$ 1.14	$ (0.21)	$ 0.93

	Previously Reported	Adjustment	Adjusted
Year Ended December 31, 2007:			
Depreciation and amortization of other assets	$ 154	$ (1)	$ 153
Interest expense	$ 406	$ (5)	$ 401
Income tax expense	$ 890	$ 2	$ 892
Net income	$ 1,451	$ 4	$ 1,455
Weighted average common and common equivalent shares outstanding assuming dilution (in millions)	487		487
Earnings per common share:			
Basic	$ 2.69	$ 0.01	$ 2.70
Diluted	$ 2.62	$ 0.01	$ 2.63

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the effect of the change in accounting principle related to our contingent convertible notes on the consolidated statement of cash flows for the years ended December 31, 2008 and 2007, respectively ($ in millions):

	Previously Reported	Adjustment	Adjusted
Year Ended December 31, 2008:			
Cash flows provided by operating activities	$ 5,236	$ 121	$ 5,357
Cash flows used in investing activities	$ (9,844)	$ (121)	$ (9,965)
Cash flows provided by financing activities	$ 6,356	$	$ 6,356
Year Ended December 31, 2007:			
Cash flows provided by operating activities	$ 4,932	$ 42	$ 4,974
Cash flows used in investing activities	$ (7,922)	$ (42)	$ (7,964)
Cash flows provided by financing activities	$ 2,988	$	$ 2,988

Bank Credit Facilities

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

	Corporate Credit Facility	Midstream Credit Facility ($ in millions)	Midstream Joint Venture Credit Facility
Borrowing capacity	$ 3,500	$ 250	$ 500
Maturity date	November 2012	September 2012	September 2012
Borrowers	Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C.	Chesapeake Midstream Operating, L.L.C. (CMO)	Chesapeake Midstream Partners, L.L.C. (CMP)
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Amount outstanding as of December 31, 2009	$ 1,892	$	$ 44
Letters of credit outstanding as of December 31, 2009	$ 41	$	$

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, none of our credit facilities contains provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Corporate Credit Facility

Our $3.5 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by certain producing natural gas and oil properties and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A. or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.00% to

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

0.75% per annum according to our senior unsecured long-term debt ratings, or (ii) 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%. 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, among other things, limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness (excluding discount on senior notes) to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.44 to 1 and our indebtedness to EBITDA ratio was 3.18 to 1 at December 31, 2009. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $75 million.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly-owned restricted subsidiaries other than minor subsidiaries.

Midstream Credit Facility

Our midstream $250 million syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems to support our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the midstream credit facility are secured by all of the assets of the wholly-owned subsidiaries (the restricted subsidiaries) of Chesapeake Midstream Development L.P. (CMD), itself a wholly-owned subsidiary of Chesapeake, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which, among other things, limit the ability of CMD and its restricted subsidiaries to incur additional indebtedness, make investments or loans, create liens and pay dividends or distributions to Chesapeake. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.01 to 1 and our EBITDA to interest expense coverage ratio was 6.87 to 1 at December 31, 2009. 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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the midstream facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMD and its restricted subsidiaries may have with an outstanding principal amount in excess of $15 million.

Midstream Joint Venture Credit Facility

Our midstream joint venture $500 million syndicated revolving bank credit facility was established concurrent with the midstream joint venture we formed on September 30, 2009 (see Note 11 for discussion regarding the midstream joint venture). As a result of that transaction, our existing midstream credit facility was amended and restated as described above. Borrowings under the midstream joint venture credit facility are secured by all of the assets of the companies organized under the joint venture, which is 50% owned by Chesapeake and 50% owned by our joint venture partner Global Infrastructure Partners, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The midstream joint venture credit facility agreement contains various covenants and restrictive provisions which, among other things, limit the ability of the joint venture and its subsidiaries to incur additional indebtedness, make investments or loans, create liens and pay dividends or distributions to Chesapeake. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.19 to 1 and our EBITDA to interest expense coverage ratio was 21.75 to 1 at December 31, 2009. If CMP or its subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream joint venture facility could be declared immediately due and payable. The midstream joint venture credit facility agreement also has cross default provisions that apply to other indebtedness CMP and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

4. Contingencies and Commitments

Litigation

On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the company and certain of its officers and directors along with certain underwriters of the company s July 2008 common stock offering. Following the appointment of a lead plaintiff and counsel, the plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. The company has filed a motion to dismiss which has not been fully briefed. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against the company s directors and certain of its officers alleging breaches of fiduciary duties relating to the disclosure matters alleged in the securities case.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7, and May 20, 2009 against the company s directors alleging breaches of fiduciary duties relating to compensation of the company s CEO and alleged insider trading, among other things, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition was filed on June 23, 2009. Chesapeake is named as a nominal defendant. Chesapeake has filed a motion to dismiss which was heard on February 1, 2010. On February 26, 2010, the court ordered that plaintiffs claims be dismissed and granted plaintiffs leave to file an amended petition within 90 days.

It is inherently difficult to predict the outcome of litigation, and we are currently unable to estimate the amount of any potential liabilities associated with the foregoing cases, which are all in preliminary stages.

Chesapeake is also involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, several mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The company has satisfactorily resolved several of the suits but some remain pending. The remaining leasehold acquisition cases are in various stages of discovery. The company believes that it has substantial defenses to the claims made in all these cases.

The company records an associated liability when a loss is probable and the amount is reasonably estimable. Although the outcome of litigation cannot be predicted with certainty, management is of the opinion that no pending or threatened lawsuit or dispute incidental to its business operations is likely to have a material adverse effect on the company s consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management s estimates.

Employment Agreements with Officers

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of employment without cause, or in the event of his incapacity, death or retirement at or after age 55. The agreement also provides for a one-time $75 million well cost incentive award with a five-year clawback. The well cost incentive award was fully applied against the CEO s obligations under the Founder Well Participation Program in 2009. See Note 6 for a description of the Founder Well Participation Program and the incentive award. The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2012. The agreements with our COO, CFO and other executive vice presidents contain a cap on cash salary for the three-year term of the agreement. In addition, annual cash bonuses will not exceed the sum of the individual EVP s cash bonus compensation for (a) the last half of 2008 and (b) the first half of 2009. These agreements provide for the continuation of salary for one year in the event of termination of employment without cause or death and, in the event of a change of control, a payment in the amount of two times the executive officer s base compensation. These executive officers are entitled to receive a lump sum payment equal to 26 weeks of cash salary following termination of employment as a result of incapacity. Any stock-based awards held by such executive officers will immediately become 100% vested upon termination of employment without cause, a change of control, death or retirement at or after age 55. The agreements also provide for a 2008 incentive award payable in four equal annual installments, the first of which was paid on September 30, 2009. The payment of each installment of the award is subject to the individual s continued employment on the date of payment, except that the unpaid installments of the award would be accelerated and paid in lump sum in the event of a change of control or a termination of employment without cause, a voluntary termination by the executive due to a material breach of contract by the company, or termination due to incapacity or death.

Environmental Risk

Due to the nature of the natural gas and oil business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a contingent liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at December 31, 2009.

Rig Leases

In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 83 drilling rigs and related equipment for $677 million and entered into a master lease agreement under which we agreed to lease the rigs from the buyer for initial terms of seven to ten years for lease payments of approximately $93 million annually. The lease obligations are guaranteed by Chesapeake and its other material restricted subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is amortized to service operations expense over the lease term. Under the rig leases, we can exercise an early purchase option after six or seven years or on the expiration of the

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic lease equal to the fair market rental value of the rigs as determined at the time of renewal.

Compressor Leases

In 2007, 2008 and 2009, our compression subsidiary sold a significant portion of its existing compressor fleet, consisting of 1,685 compressors, for $370 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from seven to ten years for aggregate lease payments of approximately $46 million annually. The lease obligations are guaranteed by Chesapeake and its other material restricted subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is amortized to natural gas and oil marketing expenses over the lease term. Under the leases, we can exercise an early purchase option after six to nine years or we can purchase the compressors at expiration of the lease for the fair market value at the time. In addition, we have the option to renew the lease for negotiated new terms at the expiration of the lease. As of December 31, 2009, approximately 324 new compressors were on order for delivery in 2010 at a cost of approximately $100 million. Our intent is to sell and lease back those compressors as they are delivered if acceptable leasing arrangements are available to us.

Future operating lease obligations related to rigs, compressors and other equipment or property are not recorded in the accompanying consolidated balance sheets. As of December 31, 2009, minimum future lease payments were as follows ($ in millions):

	Rigs	Compressors	Other	Total
2010	$ 95	$ 45	$ 7	$ 147
2011	95	45	5	145
2012	96	46	3	145
2013	97	49	2	148
2014	82	47	1	130
After 2014	60	106	1	167
Total	$ 525	$ 338	$ 19	$ 882

Rent expense, including short-term rentals, for the years ended December 31, 2009, 2008 and 2007 was $149 million, $133 million and $81 million, respectively.

Real Estate Surface Asset Leases

In April 2009, we financed 113 real estate surface assets in the Barnett Shale area in and around Fort Worth, Texas 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. As of December 31, 2009, the minimum aggregate future lease payments were approximately $859 million. Chesapeake has the option to repurchase up to a specified number of assets at any time during the term of the lease.

Transportation Contracts

Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from 2010 to 2099. These commitments are not recorded in the accompanying consolidated

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

balance sheets. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter s Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company receives rights to flow natural gas production through pipelines located in highly competitive markets. Excluded from this summary are demand charges for pipeline projects that are currently seeking regulatory approval. The aggregate amounts of such required demand payments as of December 31, 2009 are as follows ($ in millions):

2010	$ 253
2011	303
2012	297
2013	277
2014	262
After 2014	1,388
Total	$ 2,780

Drilling Contracts

We have contracts with various drilling contractors to use 26 drilling rigs with terms of one to three years. These commitments are not recorded in the accompanying consolidated balance sheets. Minimum future commitments as of December 31, 2009 are as follows ($ in millions):

2010	$ 107
2011	74
After 2011	
Total	$ 181

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 will be resold.

Other Commitments

In 2009, we financed our regional Barnett Shale headquarters building in Fort Worth, Texas for 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.

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

Table of Contents

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,		
	2009	2008	2007
	($ in millions)		
Current	$ 4	$ 423	$ 29
Deferred	(3,487)	(36)	863
Total	$ (3,483)	$ 387	$ 892

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,		
	2009	2008	2007
	($ in millions)		
Income tax expense (benefit) at the federal statutory rate (35%)	$ (3,251)	$ 347	$ 821
State income taxes (net of federal income tax benefit)	(275)	24	56
Other	43	16	15
	$ (3,483)	$ 387	$ 892

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	
	2009	2008
	($ in millions)	
Deferred tax liabilities:		
Natural gas and oil properties	$ (96)	$ (2,755)
Other property and equipment	(184)	(281)
Derivative instruments	(265)	(550)
Volumetric production payments	(937)	(943)
Contingent convertible debt	(464)	(450)
Other	(23)	
Deferred tax liabilities	(1,969)	(4,979)
Deferred tax assets:		
Net operating loss carryforwards	592	5
Asset retirement obligation	107	102
Investments	131	117
Deferred stock compensation	57	85
Accrued liabilities	22	22

Alternative minimum tax credits	25	
Other		90
Deferred tax assets	934	421
Total deferred tax asset (liability)	$ (1,035)[(a)]	$ (4,558)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 24	$
Current deferred income tax liability		(358)
Non-current deferred income tax liability	(1,059)	(4,200)
	$ (1,035)	$ (4,558)

106

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(a) In addition to the income tax benefit of $3.483 billion, activity during 2009 includes net liabilities of $48 million related to stock-based compensation and $41 million related to investments, deferred tax assets for $141 million related to derivative instruments and $106 million related to the equalization of partners capital. These items were not recorded as part of the provision for income taxes. In addition, the activity includes an increase to deferred tax liabilities of $157 million related to federal and state income tax refunds and a reduction of $39 million related to uncertain tax positions.

As of December 31, 2009, we classified $24 million of deferred tax assets as current that were attributable to the current portion of net operating losses, which was offset by current temporary differences associated with derivative assets and other items. As of December 31, 2008, we classified $358 million of deferred tax liabilities as current that were attributable to the current portion of derivative assets and other current temporary differences.

At December 31, 2009, Chesapeake had federal income tax net operating loss (NOL) carryforwards and carrybacks of approximately $889 million and $681 million, respectively. Additionally, we had $3 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and $333 million of AMT NOL carrybacks to be used against prior year AMT income. The NOL carryforwards expire from 2019 through 2029. 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 of Chesapeake is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of Chesapeake.

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

The following table summarizes our net operating losses as of December 31, 2009 and any related limitations:

	Total	Limited	Annual Limitation
		($ in millions)	
Net operating loss	$ 1,570	$ 2	$ 1
AMT net operating loss	$ 336	$ 2	$ 1

As of December 31, 2009, 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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008, the amount of unrecognized tax benefits related to regular tax liabilities and AMT associated with uncertain tax positions was $60 million. Of this amount, $48 million was related to regular tax liabilities and $12 million was related to AMT. As of December 31, 2009, the amount of unrecognized tax benefits related to regular tax liabilities and AMT associated with uncertain tax positions was $231 million. Of this amount, $87 million is related to regular tax liabilities and $144 million is related to AMT. These unrecognized tax benefits are associated with temporary differences. If these unrecognized tax benefits are disallowed and we are required to pay additional taxes, the reversal of the temporary differences associated with the regular tax liabilities will increase our tax basis which will increase our future tax deductions. Any AMT payments can be utilized as credits against future regular tax liabilities. The uncertain tax positions identified would not have a material effect on the effective tax rate. At December 31, 2009, we had an accrued liability of $10 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:

	2009	2008	2007
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 60	$ 133	$ 142
Additions based on tax positions related to the current year	171	48	64
Reductions for tax positions of prior years		(120)	(52)
Settlements		(1)	(21)
Unrecognized tax benefits at end of period	$ 231	$ 60	$ 133

Chesapeake files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. With few exceptions, Chesapeake is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years prior to 2006. The Internal Revenue Service (IRS) commenced an examination of Chesapeake s 2007 and 2008 U.S. income tax returns in October 2009.

6. Related Party Transactions

As of December 31, 2009, we had accrued accounts receivable from our CEO, Aubrey K. McClendon, of $14 million representing joint interest billings from December 2009 which were invoiced and timely paid in January 2010. 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,

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake s working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation.

On December 31, 2008, we entered into a new five-year employment agreement with Mr. McClendon that contained a one-time well cost incentive award to him. The total cost of the award to Chesapeake was $75 million plus employment taxes in the amount of approximately $1 million. We will recognize the incentive award as general and administrative expense over the five-year vesting period for the clawback described below, resulting in an expense of approximately $15 million per year that began in 2009. In addition to state and federal income tax withholding, similar employment taxes were imposed on Mr. McClendon and withheld from the award. The net incentive award of approximately $44 million was fully applied against costs attributable to interests in company wells acquired by Mr. McClendon or his affiliates under the FWPP. The incentive award is subject to a clawback 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.

As disclosed in Note 17, in 2007 Chesapeake had revenues of $1.1 billion from natural gas and oil sales to Eagle Energy Partners I, L.P., a former affiliated entity. We sold our 33% limited partnership interest in Eagle Energy in June 2007.

7. Employee Benefit Plans

Our qualified 401(k) profit sharing plan is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except certain employees of Chesapeake Appalachia, L.L.C. 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 $48 million, $40 million and $28 million to the Chesapeake plan in 2009, 2008 and 2007, respectively.

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

Prior to 2008, we maintained two nonqualified deferred compensation plans, the 401(k) make-up plan and the deferred compensation plan. Effective on January 1, 2008, the deferred compensation plans were merged into the Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan (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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. In addition, the company begins matching employee contributions with Chesapeake common stock once the employee has at least three years of service as a company employee.

Chesapeake matches 100% of employee contributions up to 15% of base salary and bonus in the aggregate for the 401(k) plan and the DC Plan. We contributed $7 million, $6 million and $4 million to the DC Plan during 2009, 2008 and 2007, 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. 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.

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

Chesapeake maintains no post-employment benefit plans except those sponsored by Chesapeake Appalachia, L.L.C. Participation in these plans is limited to existing 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, 2009, the company had accrued approximately $2 million in accumulated post-employment benefit liability.

8. Stockholders Equity, Restricted Stock and Stock Options

Common Stock

The following is a summary of the changes in our common shares outstanding for 2009, 2008 and 2007:

	2009	2008	2007
		(in thousands)	
Shares issued at January 1	607,953	511,648	458,601
Common stock issuances for cash		51,750	
Convertible note conversions/exchanges	10,210	23,913	
Preferred stock conversions/exchanges	1,423	12,673	36,652
Restricted stock issuances (net of forfeitures)	3,632	4,708	14,268
Stock option exercises	508	1,584	2,127
Common stock issued for the purchase of leasehold and unproved properties	24,823	1,677	
Shares issued at December 31	648,549	607,953	511,648

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Contingent Convertible Senior Notes

In 2009 and 2008, holders of certain of our contingent convertible senior notes exchanged or converted their senior notes for shares of common stock in privately negotiated exchanges as summarized below ($ in millions):

Year	Contingent Convertible Senior Notes	Principal Amount		Number of Common Shares
2009	2.25% due 2038	$	364	10,210,169
2008	2.75% due 2035	$	239	8,841,526
2008	2.50% due 2037		272	8,416,865
2008	2.25% due 2038		254	6,654,821
		$	765	23,913,212

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 $40 million and $27 million, respectively, on the cancellation of indebtedness for the years ended December 31, 2009 and 2008. There were no contingent convertible senior notes exchanged or converted in 2007.

Preferred Stock

The following is a summary of the changes in our preferred shares outstanding for 2009, 2008 and 2007:

	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
			(in thousands)		
Shares outstanding at January 1, 2009	3	5	2,559	2,096	144
Conversion/exchange of preferred for common stock	3				144
Shares outstanding at December 31, 2009		5	2,559	2,096	
Shares outstanding at January 1, 2008	3	5	3,450	5,750	144
Conversion/exchange of preferred for common stock			(891)	(3,654)	
Shares outstanding at December 31, 2008	3	5	2,559	2,096	144
Shares outstanding at January 1, 2007	3	4,600	3,450	5,750	2,300
Conversion/exchange of preferred for common stock		(4,595)			(2,156)
Shares outstanding at December 31, 2007	3	5	3,450	5,750	144

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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 2009, 2008 and 2007, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/ Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares	Type of Transaction
2009	6.25%	143,768	1,239,538	Conversion
	4.125%	3,033	182,887	Conversion
			1,422,425	
2008	5.0% (series 2005B)	3,654,385	10,443,642	Exchange
	4.5%	891,100	2,227,750	Exchange
	4.125%	29	1,743	Conversion
			12,673,135	
2007	5.0% (series 2005)	4,595,000	19,283,311	Exchange
	6.25%	2,156,184	17,367,823	Exchange
	6.25%	48	344	Conversion
	4.125%	3	180	Conversion
			36,651,658	

In connection with the exchanges and conversions noted above, we recorded losses of $0, $67 million and $128 million in 2009, 2008 and 2007, respectively. In general, the loss is equal to the excess of the fair value of all common stock exchanged over the fair value of the common stock issuable pursuant to the original terms of the preferred stock.

Dividends on our outstanding preferred stock are payable quarterly in cash, common stock or a combination thereof. Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2009:

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
5.00% cumulative convertible (series 2005)	April 2005	$ 100	Any time	3.8964	$ 25.6647	April 15, 2010	$ 33.3641[(a)]
4.50% cumulative convertible	September	$ 100	Any time	2.2692	$ 44.0692	September 15,	$ 57.2900[(a)]

	2005					2010	
5.00%cumulative convertible (series 2005B)	November 2005	$ 100	Any time	2.5664	$ 38.9652	November 15, 2010	$ 50.6548[(a)]

(a) Convertible at the company s option if the company s common stock equals or exceeds the trigger price for a specified time period or after the conversion date indicated if there are less than 250,000 shares of preferred stock outstanding.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 31,500,000 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 87,500 shares of restricted stock issued to our directors from this plan in each of 2009, 2008 and 2007. Additionally, there were 4.0 million, 4.5 million and 14.7 million restricted shares issued, net of forfeitures, to employees and consultants during 2009, 2008 and 2007, respectively, from this plan. As of December 31, 2009, there were 8.0 million shares remaining available for issuance under the plan.

Under Chesapeake s 2003 Stock Incentive Plan, restricted stock and incentive and nonqualified stock options to purchase our common stock may be awarded to employees and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares 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, 0.2 million and 0.2 million restricted shares, net of forfeitures, issued during 2009, 2008 and 2007, respectively, from this plan. As of December 31, 2009, there were 618,282 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 2008 and 2007, 10,000 shares of common stock were awarded to new directors from this plan. As of December 31, 2009, there were 50,000 shares remaining available for issuance under this plan.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2009
2002 and 2001 Stock Option Plans	Employees and consultants	Incentive and nonqualified	3,000,000/ 3,200,000	Yes	625,636
2002 and 2001 Nonqualified Stock Option Plans	Employees and consultants	Nonqualified	4,000,000/ 3,000,000	No	890,377
2000 and 1999 Employee Stock Option Plans	Employees and consultants	Nonqualified	3,000,000 (each plan)	No	262,428
1996 and 1994 Stock Option Plans	Employees and consultants	Incentive and nonqualified	6,000,000/ 4,886,910	Yes	73,161

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is generally four years from the date of grant for employees and three years for non-employee directors. To the extent amortization of compensation cost relates to employees directly involved in acquisition, exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized in general and administrative expense or production expense. Note 1 details the accounting for our stock-based compensation expense in 2009, 2008 and 2007.

A summary of the status of the unvested shares of restricted stock and changes during 2009, 2008 and 2007 is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2009	21,622,202	$ 38.85
Granted	8,018,409	18.65
Vested	(9,213,910)	36.38
Forfeited	(1,202,094)	34.46
Unvested shares as of December 31, 2009	19,224,607	$ 31.89
Unvested shares as of January 1, 2008	19,688,759	$ 32.42

Granted	6,800,027		51.14
Vested	(3,942,326)		28.27
Forfeited	(924,258)		37.33
Unvested shares as of December 31, 2008	21,622,202	$	38.85
Unvested shares as of January 1, 2007	7,074,761	$	25.85
Granted	15,560,570		34.25
Vested	(2,255,384)		24.34
Forfeited	(691,188)		33.29
Unvested shares as of December 31, 2007	19,688,759	$	32.42

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The aggregate intrinsic value of restricted stock vested during 2009 was approximately $193 million based on the stock price at the time of vesting.

As of December 31, 2009, there was $444 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.34 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the year ended December 31, 2009, we recognized a reduction in tax benefits related to restricted stock of $49 million. During the years ended December 31, 2008 and 2007, we recognized excess tax benefits related to restricted stock of $28 million and $5 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 stock options outstanding are fully vested and exercisable.

The following table provides information related to stock option activity for 2009, 2008 and 2007:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[a] ($ in millions)
Outstanding at January 1, 2009	2,802,421	$ 8.13		
Exercised	(508,369)	7.12		$ 8
Forfeited / Canceled	(11,200)	6.47		
Outstanding at December 31, 2009	2,282,852	$ 8.36	2.75	$ 40
Exercisable at December 31, 2009	2,282,852	$ 8.36	2.75	$ 40
Shares authorized for future grants				
Outstanding at January 1, 2008	4,445,455	$ 7.55		
Exercised	(1,639,401)	6.54		$ 66
Forfeited / Canceled	(3,633)	15.26		
Outstanding at December 31, 2008	2,802,421	$ 8.13	3.59	$ 23
Exercisable at December 31, 2008	2,801,796	$ 8.13	3.59	$ 23
Shares authorized for future grants	5,762,679			
Outstanding at January 1, 2007	6,605,703	$ 7.43		
Exercised	(2,146,640)	7.16		$ 61

Forfeited / Canceled	(13,608)		9.90				
Outstanding at December 31, 2007	4,445,455	$	7.55	4.37	$	141
Exercisable at December 31, 2007	4,422,519	$	7.51	4.36	$	140
Shares authorized for future grants	2,460,562					

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

As of December 31, 2009, there was no remaining unrecognized compensation cost related to unvested stock options.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During the years ended December 31, 2009, 2008 and 2007, we recognized excess tax benefits related to stock options of $1 million, $15 million and $15 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

The following table summarizes information about stock options outstanding at December 31, 2009:

Range of Exercise Prices		Outstanding Options Number Outstanding	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Options Exercisable Number Exercisable	Weighted-Avg. Exercise Price
$2.25	$4.00	125,611	0.31	$ 3.82	125,611	$ 3.82
5.20	5.20	260,208	2.56	5.20	260,208	5.20
5.35	5.89	121,492	1.22	5.54	121,492	5.54
6.11	6.11	422,573	1.80	6.11	422,573	6.11
6.40	7.74	85,355	1.96	6.95	85,355	6.95
7.80	7.80	383,151	3.02	7.80	383,151	7.80
7.86	10.01	111,575	2.82	8.58	111,575	8.58
10.08	10.08	430,742	3.47	10.08	430,742	10.08
10.10	15.47	254,270	4.23	13.31	254,270	13.31
15.48	22.49	87,875	5.03	19.72	87,875	19.72
$2.25	$22.49	2,282,852	2.75	$ 8.36	2,282,852	$ 8.36

9. Financial Instruments 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. 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. As of December 31, 2009 and 2008, 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.

Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike price, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the collar. This eliminates the counterparty s downside exposure below the second put option.

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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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.

The estimated fair values of our natural gas and oil derivative instruments as of December 31, 2009 and 2008 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2009		December 31, 2008	
	Volume Hedged	Fair Value ($ in millions)	Volume Hedged	Fair Value ($ in millions)
Natural gas (bbtu):				
Fixed-price swaps	492,053	$ 662	466,800	$ 863
Fixed-price collars	74,240	92	457,715	402
Fixed-price knockout swaps	38,370	17	532,660	141
Call options	996,750	(541)	551,555	(178)
Put options	(69,620)	(50)	(73,000)	(39)
Basis protection swaps	125,469	(50)	219,487	93
Total natural gas	1,657,262	$ 130	2,155,217	$ 1,282
Oil (mbbl):				
Fixed-price swaps	5,475	3	(310)	31
Fixed-price collars			730	5
Fixed-price knockout swaps	6,572	32	12,248	19
Fixed-price cap-swaps			362	3

Call options	14,975		(144)	19,355		(35)
Total oil	27,022	$	(109)	32,385	$	23
Total estimated fair value[(a)]		$	21		$	1,305

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(a) After adjusting for $407 million and $736 million of unrealized premiums, the value to be realized for these derivatives as of December 31, 2009 and 2008 was $428 million and $2.041 billion, respectively.

Pursuant to accounting guidance for hedging and derivatives, 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 as unrealized gains (losses). Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are currently reported in the consolidated statements of operations as unrealized gains (losses) within natural gas and oil sales. Realized gains (losses) are included in natural gas and oil sales in the month of related production.

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

The components of natural gas and oil sales for the years ended December 31, 2009, 2008 and 2007 are presented below.

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Natural gas and oil sales	$ 3,291	$ 7,069	$ 4,795
Realized gains (losses) on natural gas and oil derivatives	2,346	(8)	1,203
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(624)	887	(252)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	36	(90)	(122)
Total natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624

Based upon the market prices at December 31, 2009, we expect to transfer approximately $202 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to net income (loss) during the next 12 months in the related month of production. All transactions hedged as of December 31, 2009 are expected to mature by December 31, 2022.

We began 2009 with six secured hedging facilities, each of which permitted us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a stated

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

maximum value. Outstanding transactions under each of the facilities were collateralized by certain of our natural gas and oil properties that did not secure any of our other obligations. On June 11, 2009, we entered into a multi-counterparty hedge facility with 13 counterparties that have committed to provide approximately 3.9 tcfe of trading capacity and an aggregate mark-to-market capacity of $10.4 billion under the terms of the facility. The new multi-counterparty facility has consolidated and replaced the six secured hedge facilities. All trades have been novated and pledged collateral transferred to the multi-counterparty facility, which had a total of 1.7 tcfe hedged and collateral value of approximately $5.3 billion as of December 31, 2009. Trades from the original six secured hedging facilities will continue to be subject to pre-existing exposure fees, but we are not required to pay an exposure fee for any new trades in the multi-counterparty facility.

The multi-counterparty facility allows us to enter into cash-settled natural gas and oil price and basis hedges with the counterparties. Our obligations under the multi-counterparty 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, 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 hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease trading with the company on a prospective basis as long as obligations associated with any existing trades in the facility continue to be satisfied in accordance with the terms of the agreement.

To mitigate our exposure to the fluctuation in prices of diesel fuel which is used in our exploration and development activities, we have entered into diesel swaps from January 2010 to March 2010 for a total of 10.4 million gallons with an average fixed price of $1.58 per gallon. Chesapeake pays the fixed price and receives a floating price. The fair value of these swaps as of December 31, 2009 was an asset of $5 million.

Interest Rate Derivatives

To mitigate 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, 2009 and 2008, 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.

Collars: These instruments contain a fixed floor rate (floor) and a ceiling rate (cap). If the floating rate is above the cap, we have a net receivable from the counterparty and if the floating rate is below the floor, we have a net payable to the counterparty. If the floating rate is between the floor and the cap, there is no payment due from either party. Collars are used to manage our interest rate exposure related to our bank credit facilities borrowings.