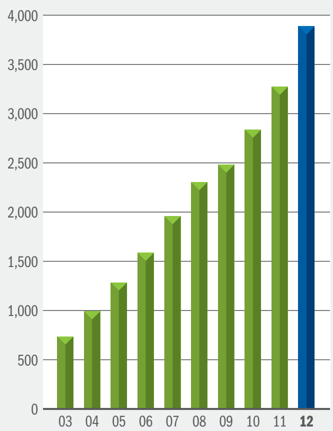
CHESAPEAKE ENERGY CORPORATION
2012 ANNUAL REPORT

CHESAPEAKE ENERGY CORPORATION (NYSE:CHK) is the second-largest producer of natural gas, a top 11 producer of oil and natural gas liquids and the most active driller of wells in the U.S. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Eagle Ford, Utica, Granite Wash, Cleveland, Tonkawa, Mississippi Lime and Niobrara unconventional liquids plays and in the Haynesville/Bossier, Marcellus and Barnett unconventional natural gas shale plays. The company also owns substantial marketing, compression and oilfield services businesses through its subsidiaries Chesapeake Energy Marketing, Inc., MidCon Compression, L.L.C. and Chesapeake Oilfield Operating, L.L.C.

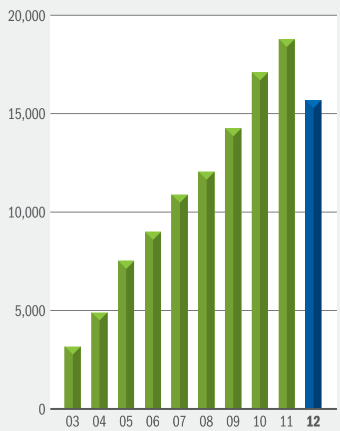
PRODUCTION GROWTH

Average mmcfe per day for year



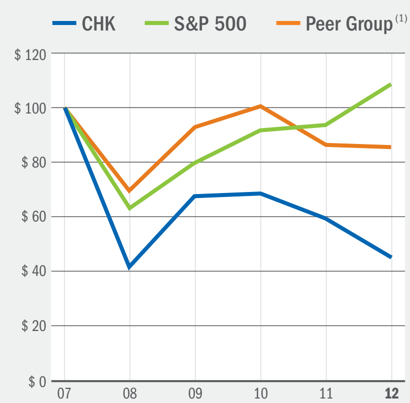
PROVED RESERVE GROWTH

Bcfe at end of year



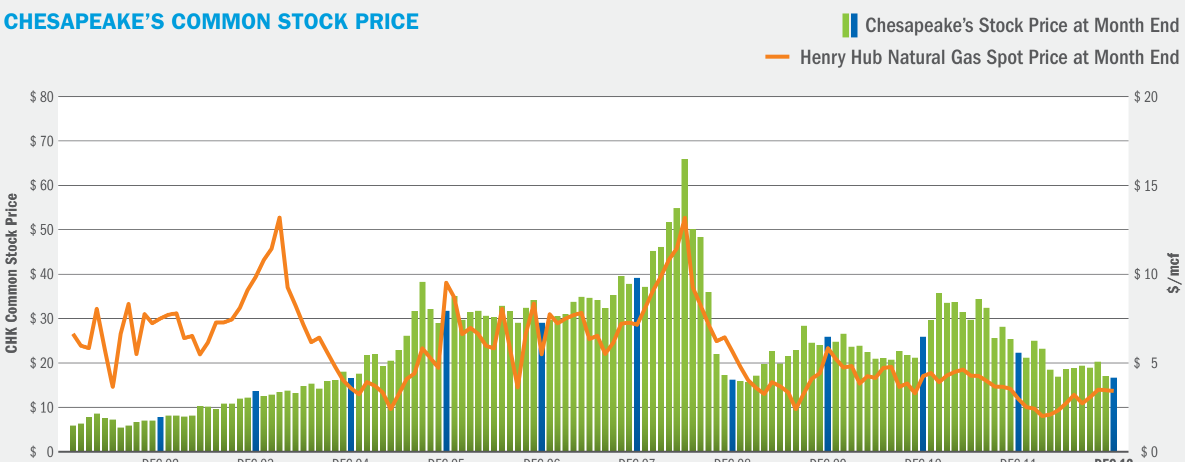
CHESAPEAKE'S FIVE-YEAR COMMON STOCK PERFORMANCE

The graph assumes an investment of $100 on December 31, 2007 and the reinvestment of all dividends.



[1] The peer group comprises of Anadarko Petroleum Corporation, Apache Corporation, Devon Energy Corporation, Encana Corporation and EOG Resources, Inc.

CHESAPEAKE'S COMMON STOCK PRICE



DEAR SHAREHOLDERS,

The past year has been a defining one for Chesapeake as we implemented many strategic and financial changes and several important governance enhancements, all while navigating the lowest natural gas prices in over a decade.

In 2012, we sold non-core assets, increased our liquids production, reduced our overall rig count by nearly half, optimized our capital expenditures, reduced administrative and operating costs, improved safety across our operations and strengthened our overall financial position. Five new independent directors and a new independent, non-executive Chairman have been appointed to our Board of Directors since June 2012. Aubrey K. McClendon, our co-founder and Chief Executive Officer, agreed with the Board to retire on April 1, 2013, and I have been tasked to serve as Acting Chief Executive Officer and as a member of a newly created three-person Office of the Chairman. Additionally, we implemented governance reforms focused on enhancing financial and management oversight, Board accountability to shareholders and corporate responsibility. I am very proud of our accomplishments and the contributions of our employees, who remain dedicated and focused in a challenging market environment.

Looking ahead, Chesapeake's management and Board are aligned on the company's business strategy and objectives. We will continue to execute our plan to develop existing assets, optimize our portfolio through targeted asset sales, strengthen our balance sheet and drive capital efficiencies throughout our organization. I am confident this strategy will generate more efficient production growth, stronger cash flow, better returns on capital and greatly improved shareholder returns.

As I write this letter, our operations continue to perform exceptionally well. The three main initiatives contributing to our strong operational performance and improving financial position include our shift to liquids, drilling the "core of the core" of our acreage and selling non-core assets.

SHIFT TO LIQUIDS

Chesapeake entered 2012 focused on continued growth of oil and natural gas liquids production to provide a more balanced portfolio of cash-flow generating assets. This initiative has been under way since 2010, and I am pleased to report great progress. During 2012, our liquids production increased nearly 47,000 barrels per day, or 54% year over year — ranking Chesapeake among the top three organic liquids growth stories in the industry. Our liquids plays are generating the strongest returns in the company, and we have accordingly allocated approximately 85% of our drilling and completion capital to liquids plays in 2013.

DRILLING THE CORE OF THE CORE

Chesapeake has shifted its operational strategy from capturing acreage to developing our extensive existing acreage positions. Chesapeake has invested billions of dollars in leasehold and infrastructure to deliver decades of production growth and cash flow. It is now time to realize the benefits of our investments and deliver efficiency gains as we transition from hold-by-production drilling to pad drilling across our asset base. Our emphasis will be to concentrate on the core of the core in these plays, which means drilling our best well next.

ASSET SALES

As a part of our ongoing efforts to strengthen our financial position and meet our funding objectives, we are executing an asset sales program primarily targeting non-core assets. This enables us to redirect capital to higher rate-of-return drilling projects and reduces our total invested capital. During 2012, we sold nearly $12 billion of assets, with the largest sales comprising our exits from the Permian Basin and the midstream business. In 2013, we are well on our way to achieving our target of $4 to $7 billion in asset sales.

OUR PATH FORWARD

Chesapeake has built one of the largest resource bases in the domestic exploration and production industry, which we believe will serve as the foundation for strong shareholder returns for decades to come. However, the path forward for Chesapeake and its shareholders is very different from our past. Our next chapter will be characterized by continued operational excellence; a prudent approach to funding future growth through fiscal and capital discipline; an increased emphasis on safety, the environment and corporate governance; and a commitment to better returns for our shareholders.

I believe we have the best employees and assets in the business, which will enable Chesapeake to further its leadership position in the energy industry. As we continue to deliver on our plan, Chesapeake will grow stronger and more profitable, and we are also well positioned to reap the benefits of a natural gas price recovery, which we believe is beginning to take hold. In my 22 years with Chesapeake, I have never been more excited and energized about our future, and I look forward to Chesapeake delivering strong results for our shareholders in 2013 and the years ahead.

Best regards,

Steven C. Dixon
Acting Chief Executive Officer
Chief Operating Officer
April 15, 2013

FINANCIAL REVIEW ($ in millions, except per share data)

Financial and Operating Data	2012	2011	2010	2009	2008	2007	2006	2005
	Years Ended December 31							
Revenues:								
Natural gas, oil and NGL	$ 6,278	$ 6,024	$ 5,647	$ 5,049	$ 7,858	$ 5,624	$ 5,619	$ 3,273
Marketing, gathering and compression	5,431	5,090	3,479	2,463	3,598	2,040	1,577	1,392
Oilfield services	607	521	240	190	173	136	130	–
Total revenues	$ 12,316	$ 11,635	$ 9,366	$ 7,702	$ 11,629	$ 7,800	$ 7,326	$ 4,665
Operating expenses:								
Natural gas, oil and NGL production	1,304	1,073	893	876	889	640	490	317
Production taxes	188	192	157	107	284	216	176	208
Marketing, gathering and compression	5,312	4,967	3,352	2,316	3,505	1,969	1,522	1,358
Oilfield services	465	402	208	182	143	94	68	–
General and administrative	535	548	453	349	377	243	139	64
Depreciation, depletion and amortization	2,811	1,923	1,614	1,615	2,144	1,988	1,462	945
Impairments and other	3,395	(391)	(116)	11,202	2,830	–	55	–
Total operating expenses	14,010	8,714	6,561	16,647	10,172	5,150	3,912	2,892
Income (loss) from operations	(1,694)	2,921	2,805	(8,945)	1,457	2,650	3,414	1,773
Interest expense	(77)	(44)	(19)	(113)	(271)	(401)	(316)	(221)
Other income (expense)	(95)	179	243	(28)	(11)	15	26	10
Miscellaneous gains (losses)	892	(176)	(145)	(202)	(184)	83	117	(70)
Total other income (expense)	720	(41)	79	(343)	(466)	(303)	(173)	(281)
Income (loss) before income taxes and cumulative effect of accounting change	(974)	2,880	2,884	(9,288)	991	2,347	3,241	1,492
Income tax expense (benefit):								
Current income taxes	47	13	–	4	423	29	5	–
Deferred income taxes	(427)	1,110	1,110	(3,487)	(36)	863	1,242	545
Net income (loss) before cumulative effect of accounting change, net of tax	(594)	1,757	1,774	(5,805)	604	1,455	1,994	947
Net income attributable to noncontrolling interests	(175)	(15)	–	(25)	–	–	–	–
Cumulative effect of accounting change, net of tax	–	–	–	–	–	–	–	–
Net income (loss) attributable to Chesapeake	$ (769)	$ 1,742	$ 1,774	$ (5,830)	$ 604	$ 1,455	$ 1,994	$ 947
Preferred stock dividends	(171)	(172)	(111)	(23)	(33)	(94)	(89)	(42)
Gain (loss) on conversion/exchange of preferred stock	–	–	–	–	(67)	(128)	(10)	(26)
Net income (loss) available to common stockholders	$ (940)	$ 1,570	$ 1,663	$ (5,853)	$ 504	$ 1,233	$ 1,895	$ 879
Earnings per common share – basic:								
Income (loss) before cumulative effect of accounting change	$ (1.46)	$ 2.47	$ 2.63	$ (9.57)	$ 0.94	$ 2.70	$ 4.76	$ 2.73
Cumulative effect of accounting change	–	–	–	–	–	–	–	–
EPS – basic	$ (1.46)	$ 2.47	$ 2.63	$ (9.57)	$ 0.94	$ 2.70	$ 4.76	$ 2.73
Earnings per common share – diluted:								
Income (loss) before cumulative effect of accounting change	$ (1.46)	$ 2.32	$ 2.51	$ (9.57)	$ 0.93	$ 2.63	$ 4.33	$ 2.51
Cumulative effect of accounting change	–	–	–	–	–	–	–	–
EPS – diluted	$ (1.46)	$ 2.32	$ 2.51	$ (9.57)	$ 0.93	$ 2.63	$ 4.33	$ 2.51
Cash provided by (used in) operating activities (GAAP)	$ 2,837	$ 5,903	$ 5,117	$ 4,356	$ 5,357	$ 4,974	$ 4,843	$ 2,407
Operating cash flow (non-GAAP)[(a)]	$ 4,069	$ 5,309	$ 5,168	$ 4,487	$ 5,299	$ 4,675	$ 4,040	$ 2,426
Balance Sheet Data (at end of period)								
Total assets	$ 41,611	$ 41,835	$ 37,179	$ 29,914	$ 38,593	$ 30,764	$ 24,413	$ 16,114
Long-term debt, net of current maturities	$ 12,157	$ 10,626	$ 12,640	$ 12,295	$ 13,175	$ 10,178	$ 7,187	$ 5,286
Total equity (deficit)	$ 17,896	$ 17,961	$ 15,264	$ 12,341	$ 17,017	$ 12,624	$ 11,366	$ 6,299
Other Operating and Financial Data								
Proved reserves in natural gas equivalents (bcfe)	15,690	18,789	17,096	14,254	12,051	10,879	8,956	7,521
Discounted future net natural gas and oil revenues (PV-10)[(b)]	$ 17,773	$ 19,878	$ 15,146	$ 9,449	$ 15,601	$ 20,573	$ 13,647	$ 22,934
Natural gas price used in reserve report (per mcf)[(c)]	$ 1.75	$ 3.19	$ 3.52	$ 3.13	$ 5.12	$ 6.19	$ 5.41	$ 8.76
Oil price used in reserve report (per bbl)[(c)]	$ 91.78	$ 88.50	$ 75.17	$ 56.72	$ 41.60	$ 90.58	$ 56.25	$ 56.41
NGL price used in reserve report (per bbl)[(c)(d)]	$ 30.81	$ 40.38	$ 32.06	–	–	–	–	–
Natural gas production (bcf)	1,129	1,004	925	835	775	655	526	422
Oil production (mmbbl)	31.3	17.0	10.9	11.8	11.2	9.9	8.7	7.7
NGL production (mmbbl)[(d)]	17.6	14.7	7.5	–	–	–	–	–
Production (bcfe)	1,422	1,194	1,035	906	843	714	578	469
Sales price per mcfe[(e)]	$ 4.02	$ 5.70	$ 6.09	$ 6.22	$ 8.38	$ 8.40	$ 8.86	$ 6.90
Production expense per mcfe	$ 0.92	$ 0.90	$ 0.86	$ 0.97	$ 1.05	$ 0.90	$ 0.85	$ 0.68
Production taxes per mcfe	$ 0.13	$ 0.16	$ 0.15	$ 0.12	$ 0.34	$ 0.30	$ 0.31	$ 0.44
General and administrative expense per mcfe	$ 0.38	$ 0.46	$ 0.44	$ 0.38	$ 0.45	$ 0.34	$ 0.24	$ 0.14
Depreciation, depletion and amortization expense per mcfe	$ 1.97	$ 1.61	$ 1.56	$ 1.78	$ 2.55	$ 2.78	$ 2.53	$ 2.02
Number of employees (full time at end of period)	11,989	12,598	10,021	8,152	7,649	6,219	4,883	2,885
Cash dividends declared per common share	$ 0.3500	$ 0.3375	$ 0.3000	$ 0.3000	$ 0.2925	$ 0.2625	$ 0.2300	$ 0.1950
Stock price (at end of period – split adjusted)	$ 16.62	$ 22.29	$ 25.91	$ 25.88	$ 16.17	$ 39.20	$ 29.05	$ 31.73

(a) A non-GAAP measure defined as cash provided by (used in) operating activities before changes in assets and liabilities. Please refer to the Investors section of our website at www.chk.com for reconciliations of non-GAAP financial measures to comparable financial measures calculated in accordance with generally accepted accounting principles.

(b) PV-10 is the present value (10% discount rate) of estimated future gross revenues to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs calculated in accordance with SEC regulations in effect at the respective year ends. Please see pages 155–157 of our Form 10-K for information on the standardized measure of discounted future net revenues.

Years Ended December 31							Six Months Ended December 31	Years Ended June 30				
2004	2003	2002	2001	2000	1999	1998	1997	1997	1996	1995	1994	1993
$ 1,936	$ 1,297	$ 568	$ 820	$ 470	$ 280	$ 257	$ 96	$ 193	$ 111	$ 57	$ 22	$ 12
773	420	171	149	158	75	121	58	76	35	9	7	5
–	–	–	–	–	–	–	–	–	–	–	–	–
$ 2,709	$ 1,717	$ 739	$ 969	$ 628	$ 355	$ 378	$ 154	$ 269	$ 146	$ 66	$ 29	$ 17
205	138	98	75	50	46	51	8	11	6	3	2	3
104	78	30	33	25	13	8	2	4	2	1	2	–
755	410	166	144	152	72	119	58	75	33	8	5	4
–	–	–	–	–	–	–	–	–	–	–	–	–
37	24	18	15	13	13	20	6	9	5	4	3	3
611	386	235	182	109	103	155	63	107	54	27	10	5
5	6	–	–	–	–	881	110	236	–	–	–	1
1,717	1,042	547	449	349	247	1,234	247	442	100	43	22	16
992	675	192	520	279	108	(856)	(93)	(173)	46	23	7	1
(167)	(154)	(112)	(98)	(86)	(81)	(68)	(18)	(18)	(14)	(7)	(3)	(2)
5	1	7	3	3	8	4	79	11	4	2	1	1
(25)	(21)	(20)	(63)	–	–	(14)	–	(7)	–	–	–	–
(187)	(174)	(125)	(158)	(83)	(73)	(78)	61	(14)	(10)	(5)	(2)	(1)
805	501	67	362	196	35	(934)	(32)	(187)	36	18	5	–
–	5	(2)	4	–	–	–	–	–	–	–	–	–
290	185	29	141	(260)	2	–	–	(4)	13	6	1	–
515	311	40	217	456	33	(934)	(32)	(183)	23	12	4	–
–	–	–	–	–	–	–	–	–	–	–	–	–
–	2	–	–	–	–	–	–	–	–	–	–	–
$ 515	$ 313	$ 40	$ 217	$ 456	$ 33	$ (934)	$ (32)	$ (183)	$ 23	$ 12	$ 4	–
(40)	(22)	(10)	(2)	(9)	(16)	(12)	–	–	–	–	–	(1)
(36)	–	–	–	7	–	–	–	–	–	–	–	–
$ 439	$ 291	$ 30	$ 215	$ 454	$ 17	$ (946)	$ (32)	$ (183)	$ 23	$ 12	$ 4	$ (1)
$ 1.73	$ 1.36	$ 0.18	$ 1.33	$ 3.52	$ 0.17	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.43	$ 0.22	$ 0.08	$ (0.02)
–	0.02	–	–	–	–	–	–	–	–	–	–	–
$ 1.73	$ 1.38	$ 0.18	$ 1.33	$ 3.52	$ 0.17	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.43	$ 0.22	$ 0.08	$ (0.02)
$ 1.53	$ 1.20	$ 0.17	$ 1.25	$ 3.01	$ 0.16	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.40	$ 0.21	$ 0.08	$ (0.02)
–	0.01	–	–	–	–	–	–	–	–	–	–	–
$ 1.53	$ 1.21	$ 0.17	$ 1.25	$ 3.01	$ 0.16	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.40	$ 0.21	$ 0.08	$ (0.02)
$ 1,432	$ 939	$ 429	$ 478	$ 315	$ 145	$ 95	$ 139	$ 84	$ 121	$ 55	$ 19	$ (1)
$ 1,403	$ 897	$ 409	$ 443	$ 306	$ 139	$ 118	$ 68	$ 161	$ 88	$ 46	$ 16	$ 4
$ 8,245	$ 4,572	$ 2,876	$ 2,287	$ 1,440	$ 851	$ 813	$ 953	$ 949	$ 572	$ 277	$ 126	$ 79
$ 3,075	$ 2,058	$ 1,651	$ 1,329	$ 945	$ 964	$ 919	$ 509	$ 509	$ 268	$ 146	$ 48	$ 14
$ 3,163	$ 1,733	$ 908	$ 767	$ 313	$ (218)	$ (249)	$ 280	$ 287	$ 178	$ 45	$ 31	$ 31
4,902	3,169	2,205	1,780	1,355	1,206	1,091	448	403	425	243	142	137
$ 10,504	$ 7,333	$ 3,718	$ 1,647	$ 6,046	$ 1,089	$ 661	$ 467	$ 437	$ 547	$ 188	$ 141	$ 142
$ 5.65	$ 5.68	$ 4.28	$ 2.51	$ 10.12	$ 2.25	$ 1.68	$ 2.29	$ 2.12	$ 2.41	$ 1.60	$ 1.98	$ 2.43
$ 39.91	$ 30.22	$ 30.18	$ 18.82	$ 26.41	$ 24.72	$ 10.48	$ 17.62	$ 18.38	$ 20.90	$ 17.41	$ 18.27	$ 18.71
–	–	–	–	–	–	–	–	–	–	–	–	–
322	240	161	144	116	109	94	27	62	52	25	7	3
6.8	4.7	3.5	2.9	3.1	4.1	6.0	1.9	2.8	1.4	1.1	0.5	0.3
–	–	–	–	–	–	–	–	–	–	–	–	–
363	268	181	161	134	133	130	38	79	60	32	10	4
$ 5.23	$ 4.79	$ 3.61	$ 4.56	$ 3.50	$ 2.10	$ 1.97	$ 2.49	$ 2.45	$ 1.84	$ 1.78	$ 2.21	$ 2.68
$ 0.56	$ 0.51	$ 0.54	$ 0.47	$ 0.37	$ 0.35	$ 0.39	$ 0.20	$ 0.15	$ 0.11	$ 0.11	$ 0.21	$ 0.67
$ 0.29	$ 0.29	$ 0.17	$ 0.20	$ 0.19	$ 0.10	$ 0.06	$ 0.07	$ 0.05	$ 0.03	$ 0.03	$ 0.15	–
$ 0.10	$ 0.09	$ 0.10	$ 0.09	$ 0.10	$ 0.10	$ 0.15	$ 0.15	$ 0.11	$ 0.08	$ 0.11	$ 0.31	$ 0.84
$ 1.69	$ 1.44	$ 1.30	$ 1.12	$ 0.81	$ 0.77	$ 1.19	$ 1.63	$ 1.36	$ 0.90	$ 0.85	$ 0.99	$ 1.09
1,718	1,192	866	677	462	424	481	360	362	344	325	250	150
$ 0.1700	$ 0.1350	$ 0.0600	–	–	–	$ 0.04	$ 0.04	$ 0.02	–	–	–	–
$ 16.50	$ 13.58	$ 7.74	$ 6.61	$ 10.12	$ 2.38	$ 0.94	$ 7.50	$ 9.81	$ 29.52	$ 5.64	$ 0.85	$ 1.18

(c) Adjusted for field differentials.
(d) Prior to 2010, NGL revenues and volumes were not material for separate presentation.
(e) Excludes unrealized gains (losses) on natural gas and oil hedging.

BOARD OF DIRECTORS (as of April 15, 2013)

Archie W. Dunham [1,2]
Chairman of the Board
Former Chairman
ConocoPhillips
Houston, Texas

Bob G. Alexander [3]
Former President and
Chief Executive Officer
National Energy Group, Inc.
Edmond, Oklahoma

Vincent J. Intrieri [2]
Senior Managing Director
Icahn Capital LP
New York, New York

R. Brad Martin [3,4]
Chairman
RBM Venture Company
Former Chairman and
Chief Executive Officer
Saks Incorporated
Memphis, Tennessee

Merrill A. "Pete" Miller, Jr. [3,4]
Chairman, President and
Chief Executive Officer
National Oilwell Varco, Inc.
Houston, Texas

Frederic M. Poses [2]
Chief Executive Officer
Ascend Performance Materials
New York, New York

Louis A. Raspino [4]
Former President and
Chief Executive Officer
Pride International, Inc.
Houston, Texas

Louis A. Simpson [2]
Chairman
SQ Advisors, LLC
Former President and
Chief Executive Officer,
Capital Operations
GEICO Corporation
Naples, Florida

(1) Office of the Chairman
(2) Nominating, Governance and Social Responsibility Committee
(3) Compensation Committee
(4) Audit Committee

MANAGEMENT TEAM (as of April 15, 2013)

Steven C. Dixon [1]
Acting Chief Executive Officer
Chief Operating Officer

Domenic J. Dell'Osso, Jr. [1]
Executive Vice President
and Chief Financial Officer

Jeffrey A. Fisher
Executive Vice President –
Production

Douglas J. Jacobson
Executive Vice President –
Acquisitions and Divestitures

Martha A. Burger
Senior Vice President –
Human and Corporate Resources

Jennifer M. Grigsby
Senior Vice President,
Treasurer and Corporate Secretary

Henry J. Hood
Senior Vice President – Land

James C. Johnson
Senior Vice President – Marketing

Michael A. Johnson
Senior Vice President –
Accounting, Controller
and Chief Accounting Officer

John M. Kapchinske
Senior Vice President – Geoscience

Stephen W. Miller
Senior Vice President – Drilling

Jeffrey L. Mobley
Senior Vice President –
Investor Relations and Research

Thomas S. Price, Jr.
Senior Vice President –
Corporate Development
and Government Relations

Cathy L. Tompkins
Senior Vice President –
Information Technology and
Chief Information Officer

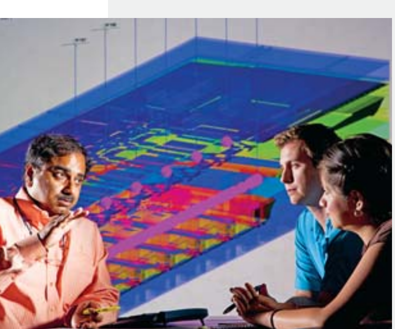
James R. Webb
Senior Vice President –
Legal and General Counsel

Jerry L. Winchester
Senior Vice President –
Oilfield Services and
Chief Executive Officer of
Chesapeake Oilfield Services

(1) Office of the Chairman

OUR COMMITMENT TO CORPORATE RESPONSIBILITY

Corporate responsibility is vital to what we do every day. Through consistent engagement with the communities where we operate, we are improving operations, reducing surface impacts, driving sustainable and profitable growth and creating value. Earlier this year we released our inaugural Corporate Responsibility Report, which provides an informative and transparent view of our operations and practices, including corporate governance, environmental, health and safety, community outreach and more. **Read the full report at chk.com/corporate-responsibility.**




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, 2012

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

For the transition period from __________ to __________

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact name of registrant as specified in its charter)

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

(405) 848-8000

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01	New York Stock Exchange
7.625% Senior Notes due 2013	New York Stock Exchange
9.5% Senior Notes due 2015	New York Stock Exchange
6.25% Senior Notes due 2017	New York Stock Exchange
6.5% Senior Notes due 2017	New York Stock Exchange
6.875% Senior Notes due 2018	New York Stock Exchange
7.25% Senior Notes due 2018	New York Stock Exchange
6.775% Senior Notes due 2019	New York Stock Exchange
6.625% Senior Notes due 2020	New York Stock Exchange
6.875% Senior Notes due 2020	New York Stock Exchange
6.125% Senior Notes due 2021	New York Stock Exchange
2.75% Contingent Convertible Senior Notes due 2035	New York Stock Exchange
2.5% Contingent Convertible Senior Notes due 2037	New York Stock Exchange
2.25% Contingent Convertible Senior Notes due 2038	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	New York Stock Exchange

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES [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, 2012 was approximately $12.2 billion. At February 21, 2013, there were 667,567,791 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2013 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
2012 ANNUAL REPORT ON FORM 10-K

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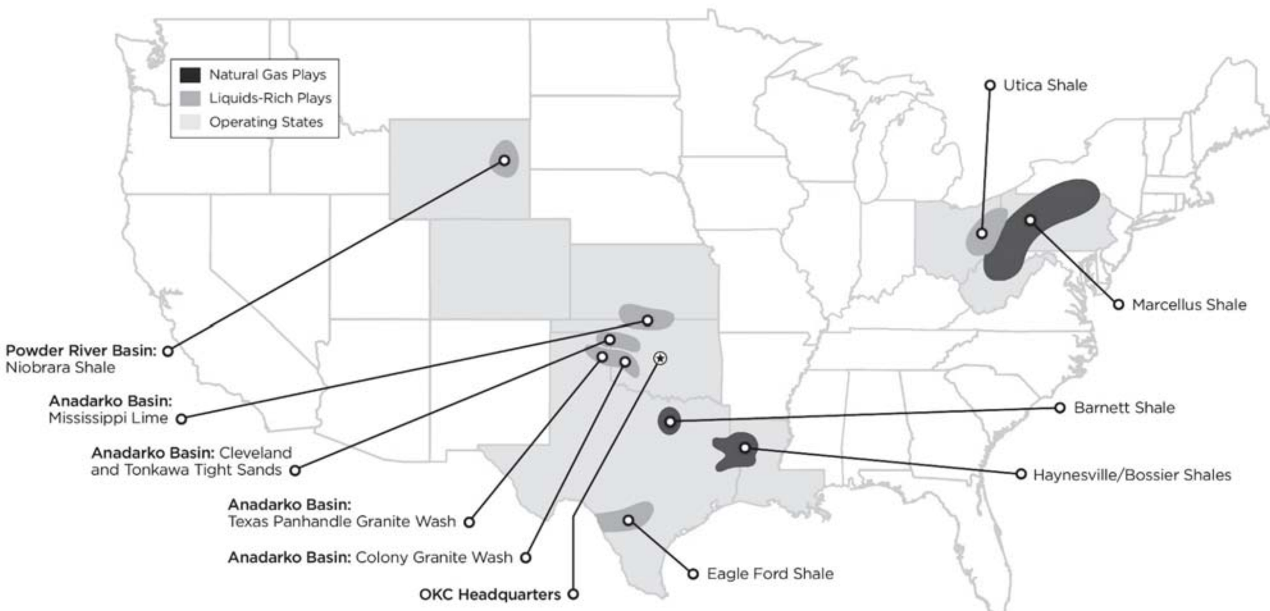
Part I

ITEM 1. *Business*

Our Business

We are the second-largest producer of natural gas, a top 11 producer of liquids and the most active driller of wells in the U.S. We own interests in approximately 45,400 producing natural gas and oil wells that are currently producing approximately 3.9 bcfe per day, net to our interest. The Company has built a large resource base of onshore U.S. unconventional natural gas and liquids assets. Our core natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania; and the Barnett Shale in the Fort Worth Basin of north-central Texas. In addition, we have built leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas; the Utica Shale in Ohio and Pennsylvania; the Granite Wash, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas; and the Niobrara Shale in the Powder River Basin in Wyoming. We have also vertically integrated many of our operations and own substantial marketing, compression and oilfield services businesses.

The map below illustrates the locations of Chesapeake's natural gas and oil exploration and production operations.



The Company's December 31, 2012 estimated proved reserves were 15.690 tcfe, a decrease of 3.099 tcfe, or 17%, from 18.789 tcfe at year-end 2011. The decrease was primarily price related as natural gas prices in 2012 declined to the lowest levels in ten years. The 2012 proved reserve movement included 6.391 tcfe of extensions, downward revisions of 5.414 tcfe resulting from lower natural gas prices and downward revisions of 1.349 tcfe resulting from changes to previous estimates. In 2012, we produced 1.422 tcfe, acquired 42 bcfe and divested 1.347 tcfe of estimated proved reserves, including the disposition of 1.013 tcfe associated with the sale of our Permian Basin assets in September and October 2012.

Natural gas prices used in estimating proved reserves as of December 31, 2012 decreased by $1.36, or 33%, to $2.76 per mcf from $4.12 per mcf as of December 31, 2011 using the trailing 12-month average prices required by the Securities and Exchange Commission (SEC). The reserve reductions included the loss of significant proved undeveloped reserves, primarily in the Barnett Shale and the Haynesville Shale plays, for which future development is uneconomic at the natural gas prices used in the reserve estimates. As a result of lower natural gas prices leading to lower estimated reserves, we were required to impair the carrying value of our natural gas and oil properties in the 2012 third quarter. See *Natural Gas and Oil Properties* in Note 1 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of this impairment and its impact on the consolidated financial statements.

Our daily production for 2012 averaged 3.886 bcfe, an increase of 614 mmcfe, or 19%, over the 3.272 bcfe of daily production for 2011, and consisted of 3.084 bcf (80% on a natural gas equivalent basis), approximately 85,420 bbls of oil (13% on a natural gas equivalent basis) and approximately 48,130 bbls of NGL (7% on a natural gas equivalent basis). Our natural gas production in 2012 grew by 12%, or 333 mmcf per day; our oil production increased by 84%, or approximately 38,950 bbls per day; and our NGL production increased by 19%, or approximately 7,820 bbls per day.

Information About Us

Our principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118 and our main telephone number at that location is (405) 848-8000. We make available free of charge on our website at *www.chk.com* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. From time to time, we also post announcements, updates, events, investor information and presentations on our website in addition to copies of all recent news releases. References to "Chesapeake", the "Company", "us", "we" and "our" in this report are to Chesapeake Energy Corporation together with its subsidiaries, unless the context otherwise requires.

Business Strategy

Since our inception in 1989, Chesapeake's primary goal has been to create value for investors by building and developing one of the largest onshore natural gas and liquids-rich resource bases in the U.S. Key elements of this business strategy are further explained below.

Grow Through the Drillbit. We believe that our most distinctive characteristic is our commitment and ability to grow production and proved reserves organically through the drillbit at a low cost in areas with large unconventional accumulations of natural gas and liquids. We are currently utilizing 83 operated drilling rigs and 31 non-operated drilling rigs to conduct the most active drilling program in the U.S. We are active in most of the nation's major unconventional plays, where we drill more horizontal wells than any other company in the industry. For many years, we have invested large amounts of capital in undeveloped leasehold, three dimensional (3-D) seismic information and human resources to take full advantage of our capacity to grow through the drillbit. As a result of those investments, we have been able to increase production for 23 consecutive years. We believe the success of our drilling program is largely due to our recognition, earlier than most of our competitors, that advanced horizontal drilling and completion techniques would enable development of previously uneconomic natural gas and liquids-rich reservoirs and that, as a consequence, various unconventional formations could be recognized and developed as potentially prolific reservoirs. For 2013 and beyond, we anticipate spending significantly less than in previous years on undeveloped leasehold, oilfield service assets and other fixed assets, and at the same time benefiting from our past investment in non-drilling assets that facilitate our ability to drill the best wells in the most efficient manner.

Increase Liquids Production. In recognition of the value gap between liquids and natural gas prices that has widened to historic levels in the last five years, we have directed a significant portion of our technological and leasehold acquisition expertise to identify, secure and commercialize new unconventional liquids-rich plays. This planned transition will result in a more balanced and likely more profitable portfolio between natural gas and liquids. To date, we have established production in multiple liquids-rich plays on approximately 6.4 million net acres. Our production of liquids averaged approximately 133,550 bbls per day during 2012, a 54% increase over the average during 2011, as a result of the increased development of our unconventional liquids-rich plays. In 2012, approximately 85% of our drilling and completion expenditures were allocated to liquids-rich plays, compared to 50% in 2011 and 30% in 2010. We are projecting that 85% of our operated drilling and completion expenditures will be allocated to liquids development in 2013 as well, and we expect to increase our liquids production through our drilling activities by approximately 27% in 2013 compared to 2012, net of expected asset sales. We project that liquids will account for more than 25% of our 2013 production and approximately 60% of our natural gas, oil and NGL revenue, after differentials and realized hedging.

Control Substantial Land and Drilling Location Inventories. Recognizing that better horizontal drilling and completion technologies, when applied to various new unconventional reservoirs, would likely create a unique opportunity to capture many years worth of drilling opportunities, we aggressively acquired leases in natural gas shale plays from 2006 through 2008 and unconventional oil plays from 2009 through 2011. We believe our lease acquisition program has given us competitive advantages in some of the best unconventional resource plays in the U.S. As of December 31, 2012, we held approximately 15 million net acres of onshore leasehold in the U.S. We believe this extensive leasehold position provides substantial opportunities for future growth and offers valuable divestiture opportunities as we focus on developing the most promising of our plays. Our undeveloped leasehold acquisition phase is now substantially complete. We spent approximately 50% less on new leasehold in 2012 than in 2011 and are forecasting to spend approximately 75% less in 2013 than in 2012.

Focus our Operations in the "Core of the Core" of Our Leasehold. We have made significant acquisitions of leasehold inventory and necessary investments in infrastructure, oilfield services, seismic data and human resources that have allowed us to drill wells more successfully and at a lower cost. Recently, we have shifted our focus to the development of the 10 plays in which we have a #1 or #2 ownership position. In an effort to optimize our portfolio around our core natural gas and oil properties, during 2012 we completed sales of non-core natural gas and oil properties, midstream and other assets for proceeds of approximately $12 billion (including $1.25 billion from the sale of a preferred security in a subsidiary), and in 2013 we are planning to sell additional natural gas and oil properties as well as midstream, certain oilfield services and other assets that do not fit our long-term plans for expected additional proceeds of approximately $4 - $7 billion. We expect that a much higher percentage of our total expenditures in 2013 will be directed toward drilling and completion activities. By concentrating on the "core of the core" of our assets, we believe we can leverage our past investments to prioritize our drilling program around our highest-return assets and enhance returns on capital.

Improve Our Balance Sheet through Reduction of Debt. Our strategic and financial plan calls for reduced long-term debt along with continued growth in production. We believe that reduced debt and continued growth in our asset base will lead to investment grade metrics. We expect to reduce debt primarily with proceeds from asset sales. Among the several benefits of lower debt are lower borrowing costs, and we believe improved credit metrics will lead to more favorable debt ratings by the major ratings agencies over time.

Mitigate Natural Gas and Oil Price Risk. We have used and intend to continue using our hedging program to mitigate the risks inherent in developing and producing natural gas and liquids-rich resources and to provide a level of cash flow certainty. We intend to periodically use the volatility in natural gas and oil prices to our benefit by adjusting our hedge position when market prices reach levels that management believes are either unsustainable for the long term, have material risk in the short term or offer unusually high rates of return on our invested capital. We currently have downside hedge protection on approximately 85% of our expected 2013 oil production and 50% of our expected 2013 natural gas production, which equates to approximately 72% of our expected 2013 natural gas, oil and NGL revenue, after differentials. We have also hedged a significant portion of our projected 2014 oil production.

Focus on Low Costs and Vertical Integration. By minimizing lease operating expenses through focused activities, vertical integration and increased scale, we strive to deliver attractive profit margins and financial returns through all phases of the commodity price cycle. Our operational efficiencies are reflected in faster spud-to-spud cycle times, overall decreases in production costs per unit and economies of scale from pad drilling. We believe our low cost structure is the result of management's effective cost-control programs, a high-quality asset base and access to oilfield services, especially those we own through our wholly and non-wholly owned subsidiaries, and natural gas processing and transportation infrastructures that exist in our key operating areas. Our high level of drilling activity and production volumes create considerable value for our oilfield services and compression businesses. As of December 31, 2012, we operated approximately 27,200 of our 45,400 gross wells, which delivered approximately 85% of our daily production volume. This large percentage of operated properties provides us with a high degree of operational flexibility and cost control.

Maintain an Entrepreneurial Culture. As an employer of approximately 12,000 people and an indirect employer of tens of thousands more, we take pride in our innovative and aggressive implementation of our business strategy and strive to be as entrepreneurial today as we were when we were a much smaller company. We have maintained an unusually flat organizational structure as we have grown to help ensure that important information travels rapidly through the Company and decisions are made and implemented quickly. Our efforts in the development of our human resources have been recognized by many, most recently Fortune Magazine, which in January 2013 named Chesapeake the 26th best company to work for in the U.S., including the second highest ranked company within the U.S. oil and gas industry. This was the sixth year in a row that we have been named by Fortune as one of the 100 Best Companies to Work for in America.

Operating Divisions

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

Southern Division. Primarily includes the Haynesville/Bossier Shales in northwestern Louisiana and East Texas and the Barnett Shale in the Fort Worth Basin of north-central Texas.

Northern Division. The Mid-Continent region, principally the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas, including the Mississippi Lime, Cleveland and Tonkawa tight sands and Granite Wash plays.

Eastern Division. Primarily includes the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania and the Utica Shale in Ohio and Pennsylvania.

Western Division. Primarily includes the Eagle Ford Shale in South Texas, the Niobrara Shale in the Powder River Basin in Wyoming and, prior to November 2012, the Permian and Delaware Basins of West Texas and southern New Mexico. In September and October 2012, we sold all of our producing properties, gathering business and substantially all of our leasehold in the Permian and Delaware Basins.

Well Data

At December 31, 2012, we had interests in approximately 45,400 gross (21,200 net) productive wells, including properties in which we held an overriding royalty interest, of which 37,300 gross (18,500 net) were classified as primarily natural gas productive wells and 8,100 gross (2,700 net) were classified as primarily oil productive wells. Chesapeake operates approximately 27,200 of its 45,400 productive wells. During 2012, we drilled 1,642 gross (1,111 net) wells and participated in another 959 gross (161 net) wells operated by other companies. We operate approximately 85% 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.

	2012				2011				2010			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	2,075	99	956	99	2,536	99	1,077	99	2,721	99	1,031	99
Dry	21	1	5	1	10	1	3	1	30	1	12	1
Total	2,096	100	961	100	2,546	100	1,080	100	2,751	100	1,043	100
Exploratory:												
Productive	495	98	305	98	430	99	201	99	265	95	99	93
Dry	10	2	6	2	3	1	1	1	15	5	7	7
Total	505	100	311	100	433	100	202	100	280	100	106	100

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

	2012		2011		2010	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Southern	363	183	1,104	550	1,023	495
Northern	942	441	1,076	342	1,371	369
Eastern	578	264	371	149	367	140
Western	718	384	428	241	270	145
Total	2,601	1,272	2,979	1,282	3,031	1,149

At December 31, 2012, we had 1,033 (461 net) wells in drilling or completing status.

Production, Sales, Prices and Expenses

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

	Years Ended December 31,		
	2012	2011	2010
Net Production:			
Natural gas (bcf)	1,128.8	1,004.1	924.9
Oil (mmbbl)	31.3	17.0	10.9
NGL (mmbbl)	17.6	14.7	7.5
Natural gas equivalent (bcfe)[a]	1,422.1	1,194.2	1,035.2
Natural Gas, Oil and NGL Sales ($ in millions):			
Natural gas sales	$ 2,004	$ 3,133	$ 3,169
Natural gas derivatives – realized gains (losses)	328	1,656	1,982
Natural gas derivatives – unrealized gains (losses)	(331)	(669)	425
Total natural gas sales	2,001	4,120	5,576
Oil sales	2,829	1,523	822
Oil derivatives – realized gains (losses)	39	(60)	74
Oil derivatives – unrealized gains (losses)	857	(128)	(1,033)
Total oil sales	3,725	1,335	(137)
NGL sales	526	603	257
NGL derivatives – realized gains (losses)	(9)	(42)	—
NGL derivatives – unrealized gains (losses)	35	8	(49)
Total NGL sales	552	569	208
Total natural gas, oil and NGL sales	$ 6,278	$ 6,024	$ 5,647
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 1.77	$ 3.12	$ 3.43
Oil ($ per bbl)	$ 90.49	$ 89.80	$ 75.29
NGL ($ per bbl)	$ 29.89	$ 40.96	$ 34.38
Natural gas equivalent ($ per mcfe)	$ 3.77	$ 4.40	$ 4.10
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 2.07	$ 4.77	$ 5.57
Oil ($ per bbl)	$ 91.74	$ 86.25	$ 82.10
NGL ($ per bbl)	$ 29.37	$ 38.12	$ 34.38
Natural gas equivalent ($ per mcfe)	$ 4.02	$ 5.70	$ 6.09
Other Operating Income[b] ($ in millions):			
Marketing, gathering and compression net margin	$ 119	$ 123	$ 127
Oilfield services net margin	$ 142	$ 119	$ 32
Expenses ($ per mcfe):			
Natural gas, oil and NGL production	$ 0.92	$ 0.90	$ 0.86
Production taxes	$ 0.13	$ 0.16	$ 0.15
General and administrative expenses	$ 0.38	$ 0.46	$ 0.44
Natural gas, oil and NGL depreciation, depletion and amortization	$ 1.76	$ 1.37	$ 1.35
Depreciation and amortization of other assets	$ 0.21	$ 0.24	$ 0.21
Interest expense[c]	$ 0.06	$ 0.03	$ 0.08

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

(b) Includes revenue and operating costs and excludes depreciation and amortization of other assets. See *Depreciation and Amortization of Other Assets* under *Results of Operations* in Item 7 of this report for details of the depreciation and amortization of other assets associated with our marketing, gathering and compression and oilfield services operating segments.

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

Natural Gas, Oil and NGL Reserves

The tables below set forth information as of December 31, 2012 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, oil and NGL reserves we own. All of our estimated natural gas and oil reserves are located within the U.S.

	December 31, 2012			
	Natural Gas	Oil	NGL	Total
	(bcf)	(mmbbl)	(mmbbl)	(bcfe)[(a)]
Proved developed	7,174	162.9	132.1	8,944
Proved undeveloped	3,759	332.6	165.2	6,746
Total proved[(b)]	10,933	495.5	297.3	15,690

	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue[(c)]	$ 20,510	$ 21,779	$ 42,289
Present value of estimated future net revenue[(c)]	$ 10,793	$ 6,980	$ 17,773
Standardized measure[(c)(d)]			$ 14,666

Operating Division	Natural Gas	Oil	NGL	Natural Gas Equivalent	Percent of Proved Reserves	Present Value
	(bcf)	(mmbbl)	(mmbbl)	(bcfe)[(a)]		($ millions)
Southern	3,532	11.7	23.4	3,742	24%	$ 1,527
Northern	2,680	153.5	130.8	4,385	28%	5,834
Eastern	3,891	9.5	34.3	4,155	26%	2,901
Western	830	320.8	108.8	3,408	22%	7,511
Total	10,933	495.5	297.3	15,690	100%	$ 17,773 [(c)]

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

(b) Includes 91 bcf of natural gas, 4 mmbbl of oil and 9 mmbbl of NGL reserves owned by the Chesapeake Granite Wash Trust, 45 bcf of natural gas, 2 mmbbl of oil and 4 mmbbl of NGL of which are attributable to the noncontrolling interest holders.

(c) Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of December 31, 2012. For the purpose of determining "prices", we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2012. The prices used in our reserve reports were $2.76 per mcf of natural gas and $94.84 per barrel of oil, before price differential adjustments. Including the effect of price differential adjustments, the prices used in our reserve reports were $1.75 per mcf of natural gas, $91.78 per barrel of oil and $30.81 per barrel of NGL. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity derivative instruments in place as of December 31, 2012. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue differs from the standardized measure only because the former does not include the effects of estimated future income tax expenses ($3.1 billion as of December 31, 2012).

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

(d) Additional information on the standardized measure is presented in Note 10 of the notes to our consolidated financial statements included in Item 8 of this report.

As of December 31, 2012, our reserve estimates included 6.746 tcfe of reserves classified as proved undeveloped (PUD), compared to 8.683 tcfe as of December 31, 2011. Presented below is a summary of changes in our proved undeveloped reserves for 2012.

	Total
	(bcfe)
Proved undeveloped reserves, beginning of period	8,683
Extensions, discoveries and other additions	4,161
Revisions of previous estimates[(a)]	(4,778)
Developed	(961)
Sale of reserves-in-place	(363)
Purchase of reserves-in-place	4
Proved undeveloped reserves, end of period	6,746

(a) Included in this amount are 4,009 bcfe of downward price-related revisions.

As of December 31, 2012, there were no PUDs that had remained undeveloped for five years or more. In 2012, we invested approximately $1.035 billion, net of drilling and completion cost carries of $86 million, to convert 961 bcfe of PUDs to proved developed reserves. In 2013, we estimate that we will invest approximately $2.4 billion, net of drilling and completion cost carries of $95 million, for PUD conversion.

The future net revenue attributable to our estimated proved undeveloped reserves of $21.779 billion as of December 31, 2012, and the $6.980 billion present value thereof, has been calculated assuming that we will expend approximately $12.0 billion to develop these reserves: $2.4 billion in 2013, $2.2 billion in 2014, $2.6 billion in 2015, $2.6 billion in 2016 and $2.2 billion in 2017, although the amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, commodity prices and the availability of capital. Chesapeake's developmental drilling schedules are subject to revision and reprioritization throughout the year resulting from unknowable factors such as the relative success in an individual developmental drilling prospect leading to an additional drilling opportunity, rig availability, title issues or delays, and the effect that acquisitions or dispositions may have on prioritizing developmental drilling plans.

The SEC's rules for reporting reserves allow the booking of proved undeveloped reserves at locations greater distances from producing wells than immediate offsets. All proved reserves are required to meet reasonable certainty standards; thus, locations more than direct offsets to producing wells must be shown to be underlain by the productive formation. Reasonable certainty also requires that the formation is continuous between the producing wells and the PUD locations and that the PUDs are economically viable.

Our proved reserves as of December 31, 2012 included PUDs more than directly offsetting producing wells in two resource plays: the Marcellus Shale and the Eagle Ford Shale. In all other areas, we restricted PUD locations to immediate offsets to producing wells. Within the Marcellus and Eagle Ford Shale plays, we used both public and proprietary geologic data to establish continuity of the formation and its producing properties. This included seismic data and interpretations (2-D, 3-D and micro seismic); open hole log information (collected both vertically and horizontally) and petrophysical analysis of the log data; mud logs; gas sample analysis; drill cutting samples; measurements of total organic content; thermal maturity; sidewall cores; whole cores; and data measured in our internal core analysis facility. After the geologic area was shown to be continuous, statistical analysis of existing producing wells was conducted to generate an area of reasonable certainty at distances from established production. Undrilled locations within this proved area could be booked as PUDs. However, due to other factors and requirements of SEC reserves reporting rules, numerous locations within the proved area of these two statistically evaluated plays have not yet been booked as PUDs.

Our annual net decline rate on producing properties is projected to be 33% from 2013 to 2014, 22% from 2014 to 2015, 17% from 2015 to 2016, 14% from 2016 to 2017 and 12% from 2017 to 2018. Of our 8.9 tcfe of proved developed reserves as of December 31, 2012, 1.2 tcfe were non-producing.

Chesapeake's ownership interest used in calculating proved reserves and the associated estimated future net revenue was determined after giving effect to the assumed maximum participation by other parties to our farm-out 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, 2012. The estimated proved reserves may not be produced and sold at the assumed prices.

The Company's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves as of December 31, 2012, 2011 and 2010, and the changes in quantities and standardized measure of such reserves for each of the three years then ended, are shown in Note 10 of the notes to the consolidated financial statements included in Item 8 of this report. No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured exactly, 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 often differ from the actual quantities of natural gas, oil and NGL that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate.

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

The table below compares our estimated proved reserves and associated present value (discounted at an annual rate of 10%) of estimated future revenue before income tax using the 2012 12-month average prices of $2.76 per mcf and $94.84 per bbl, before price differential adjustments, reflected in our reported reserve estimates and the 10-year average future NYMEX strip prices as of December 31, 2012, which were $4.85 per mcf and $87.90 per bbl, before price differential adjustments. Our cost and other assumptions are the same under the two pricing scenarios.

	December 31, 2012				
	Natural Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (bcfe)	Present Value ($ in millions)
2012 12-month average prices (SEC)[(a)]	10,933	495.5	297.3	15,690	$ 17,773
10-year average future NYMEX strip prices as of December 31, 2012[(b)]	14,742	497.2	304.2	19,550	$ 27,927

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

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

Reserves Estimation

Chesapeake's Reservoir Engineering Department prepared approximately 11% of the proved reserves estimates (by volume) disclosed in this report. Those estimates were based upon the best available production, engineering and geologic data.

Chesapeake's Vice President of Corporate Reserves is the technical person primarily responsible for overseeing the preparation of the Company's reserve estimates. His qualifications include the following:

- 37 years of practical experience in petroleum engineering, including 34 years of this experience in the estimation and evaluation of reserves;
- registered professional engineer in the state of Oklahoma;
- Bachelor of Science degree in Petroleum Engineering; and
- member in good standing of the Society of Petroleum Engineers.

We ensure that the key members of the Department have appropriate technical qualifications to oversee the preparation of reserves estimates, including, with respect to our engineers, a minimum of an undergraduate degree in petroleum, mechanical or chemical engineering or other applicable technical discipline. With respect to our engineering technicians, a minimum of a four-year degree in mathematics, economics, finance or other technical/business/science field is required. We maintain a continuous education program for our engineers and technicians on new technologies and industry advancements as well as refresher training on basic skills and analytical techniques.

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

- We follow comprehensive SEC-compliant internal policies to determine and report proved reserves. Reserves estimates are made by experienced reservoir engineers or under their direct supervision.
- The Reservoir Engineering Department reviews all of the Company's reported proved reserves at the close of each quarter.
- Each quarter, Reservoir Engineering Department managers, the Vice President of Corporate Reserves, the Executive Vice President of Production and the Chief Operating Officer review all significant reserves changes and all new proved undeveloped reserves additions.
- The Reservoir Engineering Department reports independently of any of our operating divisions.

We engaged three third-party engineering firms to prepare portions of our reserves estimates comprising approximately 89% of our estimated proved reserves (by volume) at year-end 2012. The portion of our estimated proved reserves prepared by each of our third-party engineering firms as of December 31, 2012 is presented below.

	% Prepared (by Volume)	Operating Division
Ryder Scott Company, L.P.	44%	Northern, Western
PetroTechnical Services, Division of Schlumberger Technology Corporation	24%	Eastern
Netherland, Sewell & Associates, Inc.	21%	Southern

Copies of the reports issued by the engineering firms are filed with this report as Exhibits 99.1 through 99.3. 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.

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

PetroTechnical 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 Petroleum and Natural Gas Engineering

Netherland, Sewell & Associates, Inc.

- over 30 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves
- registered professional engineer in the state of Texas
- Bachelor of Science degree in Petroleum Engineering

Costs Incurred in Natural Gas and Oil Property Acquisition, Exploration and Development

The following table sets forth historical costs incurred in natural gas and oil property acquisitions, exploration and development activities during the periods indicated:

	Years Ended December 31,		
	2012	2011	2010
	($ in millions)		
Acquisition of Properties:			
Proved properties	$ 332	$ 48	$ 243
Unproved properties	2,981	4,736	6,953
Exploratory costs	2,353	2,261	872
Development costs	6,733	5,497	4,741
Costs incurred(a)(b)	$ 12,399	$ 12,542	$ 12,809

(a) Exploratory and development costs are net of joint venture drilling and completion cost carries of $784 million, $2.570 billion and $1.151 billion in 2012, 2011 and 2010, respectively.

(b) Includes capitalized interest and asset retirement cost as follows:

Capitalized interest	$ 976	$ 727	$ 711
Asset retirement obligations	$ 32	$ 3	$ 2

As of December 31, 2012, there were no PUDs that had remained undeveloped for five years or more. In 2012, we invested approximately $1.035 billion, net of drilling and completion cost carries of $86 million, to convert 961 bcfe of PUDs to proved developed reserves.

A summary of our exploration and development, acquisition and divestiture activities in 2012 by operating division is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Acquisition of Unproved Properties	Acquisition of Proved Properties	Sales of Unproved Properties	Sales of Proved Properties	Total(a)
			($ in millions)					
Southern	363	183	$ 1,060	$ 181	$ 12	$ (50)	$ —	$ 1,203
Northern	942	441	3,055	559	14	(838)	(1,098)	1,692
Eastern	578	264	1,785	1,727	—	(731)	(7)	2,774
Western	718	384	3,186	514	306	(1,800)	(1,356)	850
Total	2,601	1,272	$ 9,086	$ 2,981	$ 332	$ (3,419)	$ (2,461)	$ 6,519

(a) Includes capitalized internal costs of $410 million and related capitalized interest of $976 million.

Acreage

The following table sets forth as of December 31, 2012 the gross and net developed and undeveloped natural gas and oil leasehold and fee mineral acreage. "Gross" acres are the total number of acres in which we own a working interest. "Net" acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our unexercised options to acquire additional acreage.

	Developed Leasehold		Undeveloped Leasehold		Fee Minerals		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
	(in thousands)							
Southern	1,018	653	327	189	141	65	1,486	907
Northern	4,606	2,458	4,242	2,863	1,056	178	9,904	5,499
Eastern	1,972	1,497	5,913	3,413	706	508	8,591	5,418
Western	625	355	4,941	2,822	350	31	5,916	3,208
Total	8,221	4,963	15,423	9,287	2,253	782	25,897	15,032

We actively acquire new leases, most of which have a three to five-year term. Managing lease expirations to ensure that we do not experience unintended material expirations is an important part of our business. Our leasehold management efforts include scheduling our drilling to establish production in paying quantities in order to hold leases by production, timely exercising our contractual rights to pay delay rentals to extend the terms of leases we value, planning leasehold asset sales and joint venture transactions to high-grade our lease inventory or to raise capital for additional development and letting some leases expire that are no longer part of our development plans.

The following table sets forth as of December 31, 2012, the expiration periods of gross and net undeveloped leasehold acres, unless production from the leasehold acreage is established prior to the expiration date, or we take action to extend the lease term.

	Acres Expiring	
	Gross Acres	Net Acres
	(in thousands)	
Years Ending December 31:		
2013	2,684	1,533
2014	3,442	2,430
2015	2,243	1,360
After 2015 and other	7,054	3,964
Total[(a)]	15,423	9,287

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

Marketing, Gathering and Compression

Marketing

Chesapeake Energy Marketing, Inc. (CEMI), one of our wholly owned subsidiaries, provides natural gas, oil and NGL marketing services, including commodity price structuring, contract administration and nomination services for Chesapeake, its joint working interest owners and other producers. We attempt to enhance the value of our natural gas and oil production by aggregating volumes to be sold to various intermediary markets, end markets and pipelines. This aggregation allows us to attract larger, more creditworthy customers that in turn assist in maximizing the prices received for our production.

Our oil and NGL production is generally sold under market sensitive short-term or spot price contracts. Our natural gas production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received by the purchaser after transportation and processing of our natural gas. Under percentage-of-index contracts, the price per mmbtu we receive for our natural gas is tied to indices published in *Inside FERC* or *Gas Daily*. Although exact percentages vary daily, as of February 2013, approximately 80% of our natural gas production was primarily sold under short-term contracts at market-sensitive prices. Sales to Plains Marketing, L.P. represented 11% of our total revenues (before the effects of hedging) for the year ended December 31, 2012. There were no sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) for the years ended December 31, 2011 and 2010.

Midstream Gathering Operations

Historically, Chesapeake invested, directly and through affiliates, in gathering systems and processing facilities to complement our natural gas operations in regions where we had significant production and additional infrastructure was required. By doing so, we were better able to manage the value received for, and the costs of, gathering, treating and processing natural gas. These systems were designed primarily to gather the Company's production for delivery into major intrastate or interstate pipelines. In addition, our midstream business provided services to joint working interest owners and other third-party customers. Chesapeake generated revenues from its gathering, treating and compression activities through various gathering rate structures. The Company also processed a portion of its natural gas at various third-party plants.

In December 2012, we sold the majority of our midstream business for proceeds of $2.160 billion, subject to post-closing adjustments, to Access Midstream Partners, L.P. (NYSE: ACMP). ACMP, formerly Chesapeake Midstream Partners, L.P., was an affiliate of ours from 2010 until we sold our investment in it during June 2012 for proceeds of $2.0 billion. See Note 11 and Note 12 of the notes to the consolidated financial statements included in Item 8 of this report for further discussion of these transactions.

Compression Operations

Since 2003, Chesapeake has built its compression business through its wholly owned subsidiary, MidCon Compression, L.L.C. (MidCon). MidCon operates wellhead and system compressors, with over 1.0 million horsepower of compression, to facilitate the transportation of natural gas primarily produced from Chesapeake-operated wells. In a series of transactions since 2007, MidCon sold 2,322 compressors (net of 231 repurchased units), a significant portion of its compressor fleet, and entered into a master lease agreement. These transactions were recorded as sales and operating leasebacks.

Our marketing activities, along with our midstream gathering and compression operations, constitute a reportable segment under accounting guidance for disclosure about segments of an enterprise and related information. See Note 17 of the notes to our consolidated financial statements included in Item 8 of this report.

Oilfield Services

We formed Chesapeake Oilfield Services, L.L.C. (now COS Holdings, L.L.C.) (COS) in 2011 to own and operate our oilfield services assets. COS is a diversified oilfield services company that provides a wide range of well site services, primarily to Chesapeake and its working interest partners. COS focuses on providing services that are strategic to our operations, represent historical bottlenecks to our operations or that provide relatively high margins to the service provider. These services include contract drilling, hydraulic fracturing, oilfield rentals, rig relocation, fluid transportation and disposal and manufacturing of natural gas compressor packages. These services are fundamental to establishing and maintaining the flow of natural gas and oil throughout the productive life of a well. A source of liquidity for COS's business is the $500 million oilfield services revolving bank credit facility described under *Liquidity and Capital Resources* in Item 7 of this report. Additionally, in October 2011, Chesapeake Oilfield Operating, L.L.C. (COO), a wholly owned subsidiary of COS, issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. Proceeds from this placement were used to make a cash distribution to its direct parent, COS, to enable it to reduce indebtedness under an intercompany note with Chesapeake. See Note 3 of the notes to the consolidated financial statements included in Item 8 of the report for further discussion of the revolving bank credit facility and senior notes.

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

Contract Drilling

Securing available rigs is an integral part of the exploration process, and therefore, owning our own drilling company, Nomac Drilling, L.L.C., is a strategic advantage for us. As of December 31, 2012, we had invested approximately $1.4 billion to build or acquire 119 drilling rigs, which are utilized primarily to drill Chesapeake-operated wells. In a series of transactions since 2006, our drilling subsidiaries have sold 68 drilling rigs (net of 26 repurchased rigs) and related equipment and subsequently leased back the rigs through 2018. These transactions were recorded as sales and operating leasebacks. The drilling rigs have depth ratings between 3,000 and 25,000 feet and range in drilling horsepower from 500 to 2,000. These drilling rigs are currently operating in Louisiana, Montana, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia and Wyoming. As of December 31, 2012, we had a fleet of 119 land drilling rigs and are the fifth largest land driller operating in the U.S.

Hydraulic Fracturing

In 2010, we began the process of building a hydraulic fracturing business under the name of Performance Technologies, L.L.C. (PTL). As part of that effort, we purchased two hydraulic fracturing fleets with an aggregate of 60,000 horsepower. As of December 31, 2012, we owned seven hydraulic fracturing fleets with an aggregate of 270,000 horsepower that provide hydraulic fracturing and other well stimulation services.

Oilfield Rentals

Our oilfield rentals business provides premium rental tools for land-based natural gas and oil drilling, completion and workover activities under the name Great Plains Oilfield Rental, L.L.C. We offer a full line of rental tools, including drill pipe, drill collars, tubing, blowout preventers, frac tanks and mud tanks and mud systems. We also provide air drilling and flowback services and services associated with the transfer of fresh water to the wellsite.

Oilfield Trucking

In 2006, we expanded our oilfield services by acquiring two privately owned oilfield trucking service companies. We now own one of the largest oilfield and heavy haul transportation companies in the industry under the names of Hodges Trucking Company, L.L.C. and Oilfield Trucking Solutions, L.L.C. Our trucks move drilling rigs, produced water, crude oil, other fluids and construction materials to and from the wellsite. As of December 31, 2012, we owned a fleet of 278 rig relocation trucks, 66 cranes and forklifts and 250 fluid service trucks.

Other Operations

Our other operations consist primarily of our natural gas compressor manufacturing business that operates under the name of Compass Manufacturing, L.L.C. in which we design, engineer, fabricate, install and sell natural gas compression units, accessories and equipment used in the production, treatment and processing of natural gas and oil. Once the compressors are complete, substantially all of the completed compressors are sold to MidCon.

Competition

We compete with both major integrated and other independent natural gas and oil companies in all aspects of our business to explore, develop and operate our properties and market our production. Some of our competitors may have larger financial and other resources than ours. Competitive conditions may be affected by future legislation and regulations as the U.S. develops new energy and climate-related policies. In addition, some of our larger competitors may have a competitive advantage when responding to factors that affect demand for natural gas and oil production, such as changing prices, domestic and foreign political conditions, weather conditions, the price and availability of alternative fuels, the proximity and capacity of natural 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 derivative strategies to manage the price of a portion of our future natural gas and oil production and to manage interest rate exposure. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*.

Regulation

General

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

Exploration and Production Operations

The laws and regulations applicable to our exploration and production operations include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to such laws and regulations include, but are not limited to:

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

Our operations may require us to obtain permits for, among other things,

- air emissions;
- construction activities, including in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species or their habitats;
- the construction and operation of underground injection wells to dispose of produced water and other non-hazardous oilfield wastes; and
- the construction and operation of surface pits to contain drilling muds and other non-hazardous fluids associated with drilling operations.

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

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

Midstream Operations

Historically, Chesapeake invested, directly and through an affiliate, in gathering systems and processing facilities to complement our natural gas operations in regions where we had significant production and additional infrastructure was required. In December 2012, however, we sold substantially all of our midstream business, and we plan to sell most of our remaining midstream business in 2013. As a result, the impact on our business of compliance with the laws and regulations described below has decreased since the beginning of 2012 and will continue to diminish as we complete additional midstream sales.

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

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

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate that complying with applicable state laws and regulations will have a material adverse effect on our financial position, cash flows or results of operations. Our natural gas pipelines have inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

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

FERC regulation affects our gathering and compression business generally. The FERC provides policies and practices across a range of natural gas regulatory activities, including, for example, its policies on open access transportation, market manipulation, ratemaking, capacity release and market transparency, and market center promotion, which indirectly affect our gathering business. In addition, the distinction between FERC-regulated transmission facilities and federally unregulated gathering and intrastate transportation facilities is a fact-based determination made by the FERC on a case-by-case basis; this distinction has also been the subject of regular litigation and change. The classification and regulation of our gathering and intrastate transportation facilities are subject to change based on future determinations by the FERC, the courts or Congress.

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

Oilfield Services Operations

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

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

The trucking industry is subject to possible regulatory and legislative changes that may affect the economics of the industry by requiring changes in operating practices or by changing the demand for common or contract carrier services or the cost of providing truckload services. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service (HOS) regulations that govern the amount of time a driver may drive in any specific period, onboard black box recorder devices or limits on vehicle weight and size. From time to time, various legislative proposals are introduced, such as proposals to increase federal, state, or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

Environmental, Health and Safety Matters

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

- requiring the installation of pollution-control equipment or otherwise restricting the way we can handle or dispose of wastes and other substances connected with operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species or their habitats;
- requiring investigatory and remedial actions to address pollution conditions caused by our operations or attributable to former operations;
- requiring noise mitigation, setbacks, landscaping, fencing, and other measures; and
- prohibiting the operations of facilities deemed to be in non-compliance with permits issued pursuant to such environmental laws and regulations.

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

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. We monitor developments at the federal and state levels to anticipate future regulatory requirements that might be imposed to reduce the costs of compliance with any such requirements. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations and that share best practices and lessons learned in relation to pollution prevention and incident investigations.

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

Hazardous Substances and Waste

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

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

Air Emissions

Our operations are subject to the federal Clean Air Act (CAA) and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations, and impose various monitoring and reporting requirements. Permits and related compliance obligations under the CAA, each state's development and promulgation of regulatory programs to comport with Federal requirements, as well as changes to state implementation plans for controlling air emissions in regional non-attainment or near-non-attainment areas, may require natural gas and oil exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies.

In 2012, the EPA published final New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that amended the existing NSPS and NESHAP standards for oil and gas facilities and created new NSPS standards for oil and gas production, transmission and distribution facilities. While these rules remain in effect, the Agency has announced that it will reexamine and reissue the rules over the next three years. In 2010, the EPA published rules that require monitoring and reporting of greenhouse gas emissions from petroleum and natural gas systems. We, along with other industry groups, filed suit challenging certain provisions of the rules and are engaged in settlement negotiations to amend and correct the rules. The EPA is also conducting a review of the National Ambient Air Quality Standards (NAAQS) for ozone that is expected to be completed in 2013.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (CWA), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. The placement of material into jurisdictional water or wetlands of the U.S. is prohibited, except in accordance with the terms of a permit issued by the United States Army Corps of Engineers. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or a state agency delegated with EPA's authority. Further, Chesapeake's corporate policy prohibits discharge of produced water to surface waters. See Item 3. *Legal Proceedings* for a description of penalties paid by us recently in connection with CWA misdemeanor violations at a road construction site in West Virginia, as well as pending EPA orders for compliance under the CWA related to well pad and pond sites in West Virginia. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

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

Hydraulic Fracturing

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

We follow applicable legal requirements for groundwater protection in our operations that are subject to supervision by state and federal regulators (including the Bureau of Land Management on federal acreage). Furthermore, our well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into aquifers.

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

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

Produced water is a by-product of natural gas and liquids extraction, regardless of whether hydraulic fracturing technology is used. Except for produced water we recycle and reuse, Chesapeake disposes of produced water in Class II underground injection control wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. These Class II wells are overseen by the EPA in its Underground Injection Control (UIC) Program. For some of our operations, EPA has delegated its UIC Program authority to a state environmental agency.

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

Legislative, regulatory and enforcement efforts, as well as guidance from regulatory agencies, at the federal level and in some states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Hydraulic fracturing is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the Safe Drinking Water Act's UIC Program and has released draft guidance documents regarding the process for obtaining a permit for hydraulic fracturing involving diesel fuel. While we believe that the draft guidance, if adopted as final guidance, would not materially affect our operations because we do not use diesel fuel in connection with our hydraulic fracturing, we cannot predict the scope of the final guidance. The EPA also has commenced a study of the potential impacts of hydraulic fracturing activities on drinking water resources, with a progress report released in late 2012 and a final draft report expected to be released for public comment and peer review in late 2014. In addition, the Bureau of Land Management (BLM) has announced its intention to publish, in the first quarter of 2013, a revised draft of proposed rules that would impose new requirements on hydraulic fracturing operations conducted on federal lands, including the disclosure of chemical additives used. The results of EPA's guidance, including its definition of diesel fuel, EPA's study, BLM's proposed rules, and other analyses by federal and state agencies to assess the impacts of hydraulic fracturing could each spur further action toward federal and/or state legislation and regulation of hydraulic fracturing activities.

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

Endangered Species

The Endangered Species Act (ESA) restricts activities that may affect areas that contain endangered or threatened species or their habitats. While some of our assets and lease acreage may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where we intend to conduct construction activity could materially limit or delay our plans. For example, as a result of a settlement reached in 2011, the U.S. Fish and Wildlife Service has published a work plan for listing more than 450 species over the next several years. Some of these species are included in the list of over 100 species that are currently proposed for listing as endangered or threatened species. In addition, the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

Global Warming and Climate Change

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

Title to Properties

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

Operating Hazards and Insurance

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

Chesapeake maintains a $75 million control of well policy that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. This insurance may not be adequate to cover all losses or exposure to liability. Chesapeake also carries a $425 million comprehensive general liability umbrella policy and a $150 million pollution liability policy. We provide workers' compensation insurance coverage to employees in all states in which we operate. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks. In addition, our insurance does not cover penalties or fines that may be assessed by a governmental authority. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. The insurance coverage that we maintain may not be sufficient to cover every claim made against us or may not be commercially available for purchase in the future.

Facilities

Chesapeake owns an office complex in Oklahoma City and owns or leases various field or administrative offices in approximately 110 cities or towns in the areas where we conduct our operations.

Executive Officers

Aubrey K. McClendon, President and Chief Executive Officer

Aubrey K. McClendon, 53, has served as Chief Executive Officer since co-founding the Company in 1989 and President since June 2012. Mr. McClendon previously served as Chairman of the Board from 1989 to June 2012. Mr. McClendon served as a director of the general partner of Access Midstream Partners, L.P. (NYSE:ACMP), formerly Chesapeake Midstream Partners, L.P., from January 2010 to June 2012. On January 29, 2013, Mr. McClendon agreed to retire from the Company, effective no later than April 1, 2013.

Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer

Domenic J. ("Nick") Dell'Osso, Jr., 36, has served as Executive Vice President and Chief Financial Officer since November 2010. Mr. Dell'Osso has also served as a director of the general partner of ACMP since June 2011. Mr. Dell'Osso served as Vice President - Finance of the Company and Chief Financial Officer of Chesapeake's wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., from August 2008 to November 2010.

Steven C. Dixon, Executive Vice President - Operations and Geosciences and Chief Operating Officer

Steven C. Dixon, 54, has served as Executive Vice President - Operations and Geosciences and Chief Operating Officer since February 2010. Mr. Dixon served as Executive Vice President-Operations and Chief Operating Officer from 2006 to February 2010 and as Senior Vice President - Production from 1995 to 2006. He also served as Vice President-Exploration from 1991 to 1995.

Jeffrey A. Fisher, Executive Vice President - Production

Jeffrey A. Fisher, 53, has served as Executive Vice President - Production since December 2012. He served as Senior Vice President - Production from 2006 to December 2012. Mr. Fisher served as Vice President - Operations for the Company's Southern Division from 2005 to 2006 and served as Operations Manager from 2003 to 2005.

Douglas J. Jacobson, Executive Vice President - Acquisitions and Divestitures

Douglas J. Jacobson, 59, has served as Executive Vice President - Acquisitions and Divestitures since 2006. He served as Senior Vice President - Acquisitions and Divestitures from 1999 to 2006.

Martha A. Burger, Senior Vice President - Human and Corporate Resources

Martha A. Burger, 60, has served as Senior Vice President - Human and Corporate Resources since 2007. She served as Treasurer from 1995 to 2007 and as Senior Vice President - Human Resources since 2000. She was the Company's Vice President - Human Resources from 1998 until 2000, Human Resources Manager from 1996 to 1998 and Corporate Secretary from 1999 to 2000. From 1994 to 1995, she served in various accounting positions with the Company, including Assistant Controller - Operations.

Jennifer M. Grigsby, Senior Vice President, Treasurer and Corporate Secretary

Jennifer M. Grigsby, 44, has served as Senior Vice President and Treasurer since 2007 and as Corporate Secretary since 2000. She served as Vice President from 2006 to 2007 and as Assistant Treasurer from 1998 to 2007. From 1995 to 1998, Ms. Grigsby served in various accounting positions with the Company.

Michael A. Johnson, Senior Vice President - Accounting, Controller and Chief Accounting Officer

Michael A. Johnson, 47, has served as Senior Vice President - Accounting, Controller and Chief Accounting Officer since 2000. He served as Vice President of Accounting and Financial Reporting from 1998 to 2000 and as Assistant Controller from 1993 to 1998.

James R. Webb, Senior Vice President - Legal and General Counsel

James R. Webb, 45, has served as Senior Vice President - Legal and General Counsel since October 2012. Prior to joining the Company, Mr. Webb was an attorney with the law firm of McAfee & Taft from February 1995 to October 2012.

Other Senior Officers

Henry J. Hood, Senior Vice President - Land

Henry J. Hood, 52, has served as Senior Vice President - Land since June 2012. He served as Senior Vice President - Land and Legal from 1997 to 2012 and as Vice President - Land and Legal from 1995 to 1997. He also served as General Counsel from April 2006 to June 2012.

James C. Johnson, Senior Vice President -Marketing

James C. Johnson, 55, has served as President of Chesapeake Energy Marketing, Inc., a wholly-owned subsidiary of the Company, and as Senior Vice President - Marketing of the Company since 2000. He served as Vice President - Contract Administration for the Company from 1997 to 2000 and as Manager - Contract Administration from 1996 to 1997.

John M. Kapchinske, Senior Vice President - Geoscience

John M. Kapchinske, 62, has been Senior Vice President - Geoscience since June 2011. He served as Vice President - Geoscience from 2005 to May 2011 and Geoscience Manager from 2001 to 2004.

Stephen W. Miller, Senior Vice President - Drilling

Stephen W. Miller, 56, has served as Senior Vice President - Drilling since 2001. He served as Vice President - Drilling from 1996 to 2001 and as District Manager - College Station District from 1994 to 1996.

Jeffrey L. Mobley, Senior Vice President - Investor Relations and Research

Jeffrey L. Mobley, 44, has served as Senior Vice President - Investor Relations and Research since 2006 and was Vice President - Investor Relations and Research from 2005 to 2006.

Thomas S. Price, Jr., Senior Vice President - Corporate Development and Government Relations

Thomas S. Price, Jr., 61, has served as Senior Vice President - Corporate Development and Government Relations since March 2009. He served as Senior Vice President - Corporate Development from 2005 to March 2009 and as Senior Vice President - Investor and Government Relations from 2003 to 2005, Senior Vice President - Corporate Development from 2000 to 2003, Vice President - Corporate Development from 1992 to 2000.

Cathlyn L. Tompkins, Senior Vice President - Information Technology and Chief Information Officer

Cathlyn L. Tompkins, 52, has served as Senior Vice President-Information Technology and Chief Information Officer since 2006. Ms. Tompkins served as Vice President - Information Technology from 2005 to 2006.

Jerry L. Winchester, Senior Vice President - Oilfield Services and Chief Executive Officer of Chesapeake Oilfield Services

Jerry L. Winchester, 54, has served as Chief Executive Officer of Chesapeake Oilfield Services, L.L.C., our oilfield services subsidiary, since September 2011 and as Senior Vice President - Oilfield Services of the Company since November 2011. From November 2010 to September 2011, Mr. Winchester served as the Vice President - Boots & Coots of Halliburton. From July 2002 to September 2010, Mr. Winchester served as the President and Chief Executive Officer of Boots & Coots International Well Control, Inc. (“Boots & Coots”), an NYSE-listed oilfield services company specializing in providing integrated pressure control and related services.

Employees

Chesapeake had approximately 12,000 employees as of December 31, 2012. This number does not include approximately 1,250 midstream employees that became ACMP employees effective January 1, 2013 as a result of the sale of substantially all of our midstream business. See Note 11 of our consolidated financial statements included in Item 8 of this report for further discussion of our midstream business divestitures.

Glossary of Natural Gas and Oil Terms

The terms defined in this section are used throughout this report.

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent.

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

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

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

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.

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 drilled at angles greater than 70 degrees from vertical.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of natural gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of natural gas equivalent.

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

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

NYMEX. New York Mercantile Exchange.

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

Present Value or PV-10. When used with respect to natural gas, oil and NGL reserves, present value, or PV-10, means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average natural gas and oil price during the preceding 12-month period prior to the end of the current reporting period, (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period) and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

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

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

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

Proved Properties. Properties with proved reserves.

Proved Reserves. Proved natural gas and oil reserves are those quantities of natural gas and oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations - prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of a reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil on the basis of available geoscience and engineering data. In the absence of 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 that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is 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 are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Reserve Replacement. Calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries and other additions and acquisitions) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table located in Note 10 of the notes to our consolidated financial statements included in Item 8 of this report. Management uses the reserve replacement ratio as an indicator of the Company's ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

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

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

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

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

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

Tbtu. One trillion British thermal units.

Tcf. One trillion cubic feet.

Tcfe. One trillion cubic feet of natural gas equivalent.

Unconventional. Plays found within regional pervasive formations with low matrix permeability and close association with hydrocarbon source rocks.

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

Unproved Properties. Properties with no proved reserves.

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

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

ITEM 1A. ***Risk Factors***

Natural gas, oil and NGL 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, oil and NGL we sell. We require substantial expenditures to replace reserves, sustain production and fund our business plans. Lower natural gas, oil and NGL prices can negatively affect the amount of cash 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, oil and NGL have been volatile and they are likely to continue to be volatile. Wide fluctuations in natural gas, oil and NGL prices may result from relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and other factors that are beyond our control, including:

- domestic and worldwide supplies of natural gas, oil and NGL, including U.S. inventories of natural gas and oil reserves;
- weather conditions;
- changes in the level of consumer and industrial demand;
- the price and availability of alternative fuels;
- the effectiveness of worldwide conservation measures;
- 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, oil and NGL price movements with any certainty. In the U.S., record-high supplies of natural gas and weak demand during 2012 resulted in natural gas prices at 10-year lows in early 2012, and while prices have risen from their lows, they remain depressed.

Further, the prices of natural gas, oil and NGL have not moved in tandem in recent years, creating a value gap that has caused us to shift our focus from dry gas plays to liquids-rich plays. In 2012, oil and NGL production accounted for only 20% of our total production but 59% of our revenue, including the effects of realized hedging, and we anticipate that approximately 60% of our 2013 revenue will come from our oil and NGL production, based on current NYMEX strip prices and our current hedging positions. Nevertheless, natural gas prices can significantly affect our future results as approximately 70% of our estimated proved reserves at December 31, 2012 were natural gas. A substantial or extended decline in natural gas, oil or NGL prices could negatively affect future revenue and the quantities of natural gas, oil and NGL reserves that may be economically produced. Even with natural gas and oil derivatives currently in place for our future production (85% of our forecasted 2013 oil production through swaps and written call options and 50% of our forecasted 2013 natural gas production through swaps and three-way collars), our revenue and results of operations will be partially exposed to changes in future commodity prices.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2012, we had long-term indebtedness of approximately $12.620 billion and unrestricted cash of $287 million, and our net indebtedness represented 41% of our total book capitalization, which we define as the sum of total equity and total current and long-term debt less unrestricted cash. We had $418 million of outstanding borrowings drawn under our oilfield services revolving bank credit facility and no outstanding borrowings under our corporate revolving bank credit facility as of December 31, 2012.

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 oilfield services revolving bank credit facility and the indenture governing the COO 6.625% Senior Notes due 2019 restrict the payment of dividends or distributions to Chesapeake;
- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants; and
- a lowering of the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings will increase the interest rate we pay on our corporate revolving bank credit facility.

The borrowing base of our corporate revolving bank credit facility is subject to periodic redetermination and is based in part on natural gas and oil prices. A lowering of our borrowing base because of lower natural gas and oil prices or for other reasons could require us to repay indebtedness in excess of the borrowing base, or we might need to further secure the lenders with additional collateral. We may incur additional debt, including secured indebtedness, in order to develop our properties and make future acquisitions. A higher level of indebtedness increases the risk that we may default on our obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, natural gas, oil and NGL prices and financial, business and other factors affect our operations and our future performance and many of these factors are beyond our control. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital. In addition, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness. We would have been unable to meet the leverage ratio maintenance covenant of our corporate revolving bank credit agreement at September 30, 2012 and had to obtain an amendment of that covenant to remain in compliance. Our lenders may not agree to an amendment or waiver of any other potential future covenant default. A default under the corporate revolving bank credit facility could result in acceleration of such indebtedness and lead to cross defaults under our other indebtedness. In this circumstance, our ability to refinance indebtedness may be limited.

We anticipate completing asset sales in 2013 and intend to apply a portion of the proceeds from such sales to reduce our overall level of indebtedness. If we are unable to consummate such sales or if they do not generate the proceeds we are anticipating, we would be required to reduce our capital spending, or seek to identify, pursue and obtain funds from other sales transactions or other sources in order to meet our operating, capital spending and debt reduction plans.

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

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. Under this method, all such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, these capitalized costs are subject to a ceiling test which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% plus the lower of cost or market value of unproved properties. The full cost ceiling is evaluated at the end of each quarter using the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ending in the quarter, adjusted for the impact of derivatives accounted for as cash flow hedges. We are required to write down the carrying value of our natural gas and oil assets if capitalized costs exceed the ceiling limit, and such write-downs can be material.

The risk that we will be required to write down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are low. Natural gas prices declined significantly in late 2011 and 2012 to the lowest level in recent years and while prices have risen from their lows, they remain depressed. As a result, our financial statements for the year ended December 31, 2012 reflect an impairment of approximately $3.315 billion recorded in the 2012 third quarter with respect to our natural gas and oil properties. Sustained low natural gas prices and other factors could cause us to be required to write down our natural gas and oil properties or other assets in the future and incur a non-cash charge against future earnings.

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

Our exploration, development and acquisition activities and our oilfield services businesses require substantial capital expenditures and we plan to make capital expenditures in 2013 that exceed our estimated 2013 cash flows from operations. Thus, we intend to fund our capital expenditures through a combination of cash flows from operations and borrowings under our corporate and oilfield services revolving bank credit facilities and, to the extent those sources are not sufficient, from debt and equity issuances, other financings and asset sales. Our ability to generate operating cash flow is subject to many of the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. Future cash flows from operations are subject to a number of risks and variables, such as the level of production from existing wells, prices of natural gas and oil, our success in developing and producing new reserves and the other risk factors discussed herein. Our ability to obtain capital from other sources, such as the capital markets, other financings and asset sales, is dependent upon many of those same factors as well as the orderly functioning of credit and capital markets. If such proceeds are inadequate to fund our planned spending, we would be required to reduce our capital spending, seek to sell different or additional assets or pursue other funding alternatives, and we could have a reduced ability to replace our reserves and increase liquids production.

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 43% of our total estimated proved reserves (by volume) as of December 31, 2012 were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates at December 31, 2012 reflected a decline in the production rate on producing properties of approximately 33% in 2013 and 22% in 2014. Thus, our future natural gas and oil reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

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

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

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

At December 31, 2012, approximately 43% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflect our plans to make significant capital expenditures to convert our proved undeveloped reserves (PUDs) into proved developed reserves, including approximately $12.0 billion during the five years ending in 2017. You should be aware that the estimated development costs may not be accurate, development may not occur as scheduled and results may not be as estimated. If we choose not to develop PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove the associated volumes from our reported proved reserves.

In addition, under the SEC's reserve reporting rules, because PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to write off any PUDs that are not developed within this five-year time frame.

You should not assume that the present values included in this report represent the current market value of our estimated reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The price on the date of estimate is calculated as the average natural gas and oil price during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. The December 31, 2012 present value is based on $2.76 per mcf of natural gas and $94.84 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, oil and NGL purchasers or in governmental regulations or taxation will also affect the actual future net cash flows from our production.

The timing of both the production and the expenses from the development and production of natural gas and oil properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. In addition, the 10% discount factor which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with our business or the natural gas and oil industry in general will affect the accuracy of the 10% discount factor.

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

We have acquired 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 have acquired unproved properties and leased undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Drilling for natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues, state or local bans or moratoriums on hydraulic fracturing and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for natural gas and oil, costs associated with producing natural gas, oil and NGL 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, leasing of undeveloped acreage or drilling a well, whether natural gas or oil is present or may be produced economically. The use of seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies. Drilling results in our newer natural gas and liquids-rich unconventional plays may be more uncertain than in unconventional plays that are more developed and have longer established production histories; meanwhile drilling and completion techniques that have proven to be successful in other unconventional formations to maximize recoveries may be unsuccessful when used in new unconventional formations.

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

Leases on natural gas and oil properties typically have a term of three to five years after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. While we seek to actively manage our leasehold inventory using our drilling rig fleet and oilfield services to drill sufficient wells to hold the leasehold that we believe is material to our operations, our drilling plans for these areas are subject to change based upon various factors, including drilling results, natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

Our hedging activities may reduce the realized prices we receive for our natural gas, oil and NGL sales, require us to provide collateral for hedging liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.

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

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

Most of our natural gas and oil derivative contracts are with the 17 counterparties to our multi-counterparty hedging facility. Our obligations under the facility are secured by natural gas and oil proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times. Under certain circumstances, such as a spike in volatility measures without a corresponding change in commodity prices, the collateral value could fall below the coverage designated, and we would be required to post additional reserve collateral to our hedging facility. If we did not have sufficient unencumbered natural gas and oil properties available to cover the shortfall, we would be required to post cash or letters of credit with the counterparties. Future collateral requirements are dependent to a great extent on natural gas and oil prices.

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

Natural gas and oil operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of natural gas, oil, brine or well fluids and other environmental hazards and risks. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, loss of equipment or otherwise negatively impacting the projected economic performance of our prospects. If any of these risks occurs, we could sustain substantial losses as a result of:

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

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

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

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

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

Additionally, the EPA has asserted federal regulatory authority over hydraulic fracturing activities involving diesel fuel (specifically, when diesel fuel is utilized in the stimulation fluid) under the Safe Drinking Water Act and is drafting guidance documents related to this newly asserted regulatory authority. There are also certain governmental reviews either underway or being proposed that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate such activities.

Certain environmental and other groups have suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. We cannot predict whether additional federal, state or local laws or regulations will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed through the adoption of new laws and regulations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

Federal regulatory initiatives relating to air emissions could result in increased costs and additional operating restrictions or delays.

The EPA has published New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that amended existing NSPS and NESHAP standards for oil and gas facilities and created new NSPS standards for oil and gas production, transmission and distribution facilities. The Agency has indicated that it will reexamine and reissue these rules over the next three years, but the outcome of this process remains uncertain. In addition, the EPA has issued rules requiring monitoring and reporting of greenhouse gas emissions from petroleum and natural gas systems. We, along with other industry groups, filed suit challenging certain provisions of these rules, but the outcome of the challenge is uncertain and may impact our reporting obligations. The EPA is also conducting a review of the National Ambient Air Quality Standards (NAAQS) for ozone, which is expected to be completed in 2013 and could result in more stringent air emissions standards applicable to our operations.

Federal regulatory initiatives relating to the protection of threatened or endangered species could result in increased costs and additional operating restrictions or delays.

The designation of previously unidentified endangered or threatened species pursuant to the ESA in areas where we intend to conduct construction activity could materially limit or delay our plans. For example, as a result of a settlement reached in 2011, the U.S. Fish and Wildlife Service is required to make a determination on the listing of more than 250 species as endangered or threatened over the next several years. Some of these species are included in the list of over 100 species that are currently proposed for listing as endangered or threatened species. In addition, the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

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

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

Federal Taxation of Independent Producers

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

OTC Derivatives Regulation

In July 2010, the U.S. Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which contains measures aimed at migrating over-the-counter (OTC) derivative markets to exchange-traded and cleared markets. Certain companies that use swaps to hedge commercial risk, referred to as end-users, are permitted to continue to use OTC derivatives under newly adopted regulations. We maintain an active price and basis protection hedging program related to the natural gas and oil we produce to manage the risk of low commodity prices and to predict with greater certainty the cash flow from our hedged production. We have used the OTC market exclusively for our natural gas and oil derivative contracts. The Dodd-Frank Act and the rules and regulations promulgated thereunder should permit us, as an end user, to continue to utilize OTC derivatives, but could cause increased costs and reduce liquidity in such markets. Such changes could materially reduce our hedging opportunities and negatively affect our revenues and cash flow during periods of low commodity prices.

Climate Change

Various state governments and regional organizations are considering enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as our equipment and operations. At the federal level, the EPA has already made findings and issued regulations that require us to establish and report an inventory of greenhouse gas emissions. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the natural gas and oil that we sell. The potential increase in our operating costs could include new or increased costs to obtain permits, operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Even without federal legislation or regulation of greenhouse gas emissions, states may pursue the issue either directly or indirectly. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and gas industry. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas and oil.

The current worldwide economic uncertainty may have a material adverse effect on our results of operations, liquidity and financial condition.

The recovery from the global economic crisis of 2008 and resulting recession has been slow and uneven. Continuing concerns regarding the worldwide economic outlook and sovereign debt crisis in Europe have contributed to increased economic uncertainty and diminished expectations for the global economy. A slowdown in the current economic recovery or a return to a recession would negatively impact demand for petroleum products and prices for natural gas, oil and NGL. These circumstances could adversely impact our results of operations, liquidity and financial condition.

Our cash flow from operations, our revolving bank credit facilities and cash on hand historically have not been sufficient to fund all of our expenditures, and we have relied on the capital markets and asset sales 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 sales 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 if our counterparties are unable to perform their obligations or seek bankruptcy protection; or
- the ability of our joint venture partners to meet their obligations to fund a portion of our drilling costs under our joint venture agreements.

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

From time to time, we experience delays in drilling and completing our natural gas and oil wells. In developing plays, the demand for equipment such as pipe and compressors can exceed the supply, and it is challenging to attract and retain qualified oilfield workers. Delays in developing our natural gas and oil assets for these and other reasons could negatively affect our revenues and cash flow.

In certain natural gas and liquids-rich shale plays, the capacity of gathering systems and transportation pipelines is insufficient to accommodate potential production from existing and new wells. We rely heavily on third parties to meet our natural gas, oil and NGL gathering demand following the sale of substantially all of our midstream business in 2012. Capital constraints could limit the construction of new pipelines and gathering systems by third parties, and we may experience delays in building intrastate gathering systems necessary to transport our natural gas to interstate pipelines. Until this new capacity is available, we may experience delays in producing and selling our natural gas, oil and NGL. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas, oil or NGL 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, oil and NGL production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions, an action we took in 2012. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

There are significant costs associated with pending legal and governmental proceedings, and the ultimate outcome of these matters is uncertain.

The Company and current and former directors and officers are the subject of a number of shareholder lawsuits, and there are ongoing governmental and regulatory investigations and inquiries. The Company cannot predict the outcome or impact of these pending matters, but the lawsuits could result in judgments against the Company and directors and officers named as defendants and there could be one or more enforcement actions in respect of the governmental investigations. For example, we could be exposed to enforcement or other actions with respect to the continuing SEC investigation into certain disclosure, accounting and financial reporting matters. Our legal expenses increased in 2012 compared to 2011 due primarily to defending the shareholder lawsuits, responding to governmental investigations and inquiries, and conducting the Board's review of certain matters involving our Chief Executive Officer, and such expenses in the future may be significant. In addition, attention to these matters by members of our senior management has been required, reducing the time they have available to devote to managing the Company's business.

Cyber attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of natural gas, oil and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. We have been the subject of cyber attacks on our internal systems and through those of third parties, but these incidents did not have a material adverse impact on our results of operations. Nevertheless, unauthorized access to our seismic data, reserves information or other proprietary or commercially sensitive information could lead to data corruption, communication interruption, or other disruptions in our exploration or production operations or planned business transactions, any of which could have a material adverse impact on our results of operation. Further, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber attacks.

We are currently involved in a search for a new CEO and if this search is delayed or if we were to lose the services of other key personnel, our business could be negatively impacted.

On January 29, 2013, Aubrey K. McClendon, our President, Chief Executive Officer (CEO) and a director, agreed with the Board of Directors to retire from the Company. Mr. McClendon will continue to serve as CEO, President and a director until the earlier of April 1, 2013 or the time at which his successor is appointed. To the extent there is a delay in choosing a new CEO, the Company's business could be negatively impacted. In addition, our future success depends in part upon the continued service of key members of our senior management team. Our senior management team is critical to the overall management of the Company and they also play a key role in maintaining our culture and setting our strategic direction. All of our executive officers and key employees are at-will employees. The loss of key personnel could seriously harm our business.

We rely on highly skilled personnel and, if we are unable to retain or motivate key personnel, hire qualified personnel, or maintain our corporate culture, our operations may be negatively impacted.

Our performance largely depends on the talents and efforts of highly skilled individuals. Our future success depends on our continuing ability to identify, hire, develop, motivate, and retain highly skilled personnel for all areas of our organization. Competition in our industry for qualified employees is intense, and certain of our competitors have directly targeted our employees. In addition, our compensation arrangements may not always be successful in attracting new employees and retaining and motivating our existing employees. Our continued ability to compete effectively depends on our ability to attract new employees and to retain and motivate our existing employees. In addition, we believe that our corporate culture fosters innovation, creativity, and teamwork. We believe that our ability to maintain our corporate culture is an important component of our future success.

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 and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek an indeterminate amount of damages. We estimate and provide for potential losses that may arise out of litigation and regulatory proceedings to the extent that such losses are probable and can be reasonably estimated. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different. Our total estimated liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. We account for legal defense costs in the period the costs are incurred.

July 2008 Common Stock Offering. On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the Company and certain of its officers and directors along with certain underwriters of the Company’s July 2008 common stock offering. Following the appointment of a lead plaintiff and counsel, the plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. On September 2, 2010, the court denied the defendants’ motion to dismiss, and the court certified the class on March 30, 2012. Defendants moved for summary judgment on grounds of loss causation and materiality on December 16, 2011, and the motion was fully briefed as of

August 21, 2012. Discovery in the case is proceeding. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case.

A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against certain current and former directors and officers of the Company asserting breaches of fiduciary duties relating to alleged material omissions in the registration statement for the July 2008 offering. On October 22, 2012, the court issued an order staying the derivative action until resolution of the federal class action. A second derivative action relating to the July 2008 offering was filed against certain current and former directors and officers of the Company in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. This action also asserts breaches of fiduciary duties with respect to alleged material omissions in the offering registration statement. On November 30, 2011, the Company filed a motion to dismiss the action, which was denied on September 28, 2012. Pursuant to court order, nominal defendant Chesapeake filed an answer on October 12, 2012. By stipulation between the parties, the individual defendants are not required to answer the complaint unless and until the plaintiff establishes standing to pursue claims derivatively.

2008 CEO Compensation and Related Party Transaction. Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7 and May 20, 2009 against the Company's directors alleging, among other things, breaches of fiduciary duties relating to the 2008 compensation of the Company's CEO, Aubrey K. McClendon, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition naming Chesapeake as a nominal defendant was filed on June 23, 2009. Chesapeake's motion to dismiss was granted on February 26, 2010, and the Oklahoma Court of Civil Appeals affirmed the dismissal on August 26, 2011. The plaintiffs filed a petition for writ of certiorari with the Oklahoma Supreme Court on September 13, 2011. The appeal is currently stayed pending resolution of the settlement referenced in the following paragraph.

On January 30, 2012, the District Court of Oklahoma County, Oklahoma approved a settlement between the parties in the consolidated derivative action, as well as a case on appeal at the Oklahoma Court of Civil Appeals requesting inspection of Company books and records relating to the December 2008 employment agreement with Mr. McClendon. The principal terms of the settlement include the rescission of the sale of an antique map collection that occurred in December 2008 between Mr. McClendon and the Company, whereby Mr. McClendon will pay the Company approximately $12 million plus interest and the Company will reconvey the map collection to Mr. McClendon, and the adoption and/or implementation of a variety of corporate governance measures. The court awarded attorney fees and expenses to plaintiffs' counsel in the amount of $3.75 million. Pursuant to the settlement, the consolidated derivative action and books and records action were dismissed with prejudice against all defendants. On February 29, 2012, certain shareholders filed a petition in error with the Oklahoma Supreme Court opposing the terms of the settlement. Their appeal was fully briefed as of October 24, 2012.

On September 6 and 8, 2011, in separate derivative actions filed in the U.S. District Court for the Western District of Oklahoma against certain of the Company's current and former directors, two shareholders alleged that the Chesapeake Board wrongfully refused their demands to investigate purported breaches of fiduciary duties relating to Mr. McClendon's 2008 compensation and, as a result, each of these shareholders asserts he is entitled to seek relief on behalf of the Company. These federal derivative actions were consolidated on December 23, 2011 and on March 14, 2012 were stayed until 30 days after the Supreme Court of Oklahoma resolves the appeal of the settlement of the consolidated derivative action and books and records action.

FWPP, Conflict of Interest and Other Matters. From April 19 to June 29, 2012, 13 substantially similar shareholder derivative actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company and its directors alleging, among other things, violations of Section 14 of the Securities Exchange Act of 1934 and Rule 14a-9 promulgated thereunder for purported material misstatements in the Company's 2009 and subsequent proxy statements related to Mr. McClendon's participation in the Founder Well Participation Program (FWPP) and breaches of fiduciary duties, corporate waste, and unjust enrichment against the Board for failing to make proper disclosures in the proxy statements and failing to properly monitor Mr. McClendon's personal use of assets acquired pursuant to the FWPP. As described in Note 6, in conjunction with Mr. McClendon's employment agreement with the Company, the FWPP provides Mr. McClendon a contractual right through June 2014 to participate and invest as a working interest owner (with up to a 2.5% working interest) in new wells drilled on the Company's leasehold. On July 13, 2012, these 13 shareholder actions were consolidated into a single case. On April 27, 2012, a shareholder derivative action was filed in the District Court of Oklahoma County, Oklahoma setting forth substantially similar claims to those alleged in the federal shareholder actions. Plaintiffs in both the federal consolidated derivative action and the state court derivative action stipulated to stay their cases pending a ruling on the motion to dismiss filed in the federal securities class action described in the following paragraph. On February 6, 2013, another shareholder derivative suit was filed in the District Court of Oklahoma County, Oklahoma asserting claims substantially similar to those of the stayed derivative cases and seeking a temporary restraining order barring the Company from providing Mr. McClendon severance compensation and benefits. The hearing for the restraining order is set for March 29, 2013.

A putative class action was filed in the U.S. District Court for the Western District of Oklahoma on April 26, 2012 against the Company and Mr. McClendon alleging violations of Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934. On July 20, 2012, the court appointed a lead plaintiff, which filed an amended complaint on October 19, 2012 against the Company, Mr. McClendon and certain other officers. The amended complaint asserts claims under Sections 10(b) (and Rule 10b-5) and 20(a) of the Securities Exchange Act of 1934 based on alleged misrepresentations regarding the Company's asset monetization strategy, including liabilities associated with its volumetric production payment (VPP) transactions, as well as Mr. McClendon's personal loans and the Company's internal controls. The action seeks class certification, damages of an unspecified amount and attorneys' fees and other costs. The Company and other defendants filed a motion to dismiss the action on December 6, 2012, and the plaintiff filed its response on January 23, 2013. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case.

On June 19, July 17 and July 20, 2012, putative class actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company, Chesapeake Energy Savings and Incentive Stock Bonus Plan (the Plan), and certain of the Company's officers and directors alleging breaches of fiduciary duties under the Employee Retirement Income Security Act (ERISA). The actions are brought on behalf of participants and beneficiaries of the Plan, and allege that as fiduciaries of the Plan, defendants owed fiduciary duties, which they purportedly breached by, among other things, failing to manage and administer the Plan's assets with appropriate skill and care, failing to disclose material information concerning such matters as Mr. McClendon's participation in the FWPP and his related financing arrangements and the Company's VPP transactions, engaging in activities that were in conflict with the best interest of the Plan, and permitting the Plan to over-concentrate in Chesapeake stock. The plaintiffs seek class certification, damages of an unspecified amount, equitable relief, and attorneys' fees and other costs. The three cases have been consolidated, and a consolidated amended complaint was filed on February 21, 2013. Defendants have 60 days from that date in which to respond. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.

On May 2, 2012, Chesapeake and Mr. McClendon received notice from the U.S. Securities and Exchange Commission that its Fort Worth Regional Office had commenced an informal inquiry into, among other things, certain of the matters alleged in the foregoing lawsuits. On December 21, 2012, the SEC's Fort Worth Regional Office advised Chesapeake that its inquiry is continuing as an investigation, and it has issued subpoenas for information and testimony. The Company, including Mr. McClendon, is providing information to the SEC in connection with this matter. The Company is also responding to related inquiries from other governmental and regulatory agencies and self-regulatory organizations.

Director and Officer Use of Company Aircraft. On May 8, 2012, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against the Company's directors alleging, among other things, breaches of fiduciary duties and corporate waste related to the Company's officers and directors' use of the Company's fractionally owned corporate jets. Chesapeake was named a nominal defendant in the derivative action. On August 21, 2012, the District Court granted the Company's motion to dismiss the case. On December 6, 2012, the plaintiff filed an amended petition in error with the Oklahoma Supreme Court, and on December 26, 2012 nominal defendant/appellee Chesapeake filed its response. The appeal is currently before the Oklahoma Court of Appeals by appointment of the Supreme Court.

Antitrust Investigations. On June 29, 2012, Chesapeake received a subpoena duces tecum from the Antitrust Division, Midwest Field Office of the U.S. Department of Justice. The subpoena requires the Company to produce certain documents before a grand jury in the Western District of Michigan, which is conducting an investigation into possible violations of antitrust laws in connection with the purchase and lease of oil and gas rights. The Company has also received demands for documents and information from certain state governmental agencies in connection with other investigations relating to the Company's purchase and lease of oil and gas rights. Chesapeake has been providing information in response to these investigations. Chesapeake's Board of Directors commenced its own investigation of these allegations in June 2012 and has recently announced the results. See *Recent Developments* in Item 7 of this report for further discussion.

Business Operations. Chesapeake is 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 contract actions, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their natural gas and oil interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal. As of December 31, 2012, we have increased natural gas and oil properties by $127 million for three specific performance cases which would require us to acquire natural gas and oil interests. Of this amount, $104 million relates to a judgment entered in July 2012 against us in an action for specific performance of 2008 contracts to purchase natural gas and oil properties. We are also recording interest on the judgment. The original trial court's holding that the contracts were not enforceable was reversed on appeal. The Company has posted a supersedeas bond to stay enforcement of the judgment and has filed a motion for new trial and/or to alter or amend the judgment. Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to the Company's business operations is likely to have a material adverse effect on its consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Environmental Risk

The nature of the natural gas and oil business carries with it certain environmental risks for Chesapeake and its subsidiaries. Chesapeake has implemented various policies, procedures, training and auditing to reduce and mitigate such environmental risks. Chesapeake conducts periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are set for potential environmental liabilities that are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions and divestitures by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and addressing the potential liability. Depending on the extent of an identified environmental concern, Chesapeake may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition, or agree to assume liability for the remediation of the property.

There are presently pending against our subsidiary, Chesapeake Appalachia, L.L.C. (CALLC), orders for compliance first initiated in the 2010 fourth quarter by the U.S. Environmental Protection Agency (EPA) related to our compliance with Clean Water Act (CWA) permitting requirements in West Virginia. We have responded to all pending orders and are actively working with the EPA to resolve these matters. For one site subject to an EPA order for compliance, CALLC pled guilty in the U.S. District Court for the Northern District of West Virginia on October 5, 2012, to three misdemeanor counts of unauthorized discharge of dredge or fill materials into a water of the U.S. On December 3, 2012, CALLC was sentenced to a two-year probation term and a fine of $200,000 for each misdemeanor, for a total fine of $600,000. We have paid the fine in full and believe that we are in material compliance with the terms of probation.

The CWA provides authority for significant civil penalties for the placement of fill in a jurisdictional stream or wetland without a permit from the Army Corps of Engineers. CWA civil penalties can be as high as $37,500 per day, per violation. The CWA sets forth subjective criteria, including degree of fault and history of prior violations, that influence CWA penalty assessments, and the EPA may also seek to recover the economic benefit derived from non-compliance. While we expect that resolution of the EPA's orders for compliance will include monetary sanctions exceeding $100,000, we believe the liability with respect to these matters will not have a material effect on the consolidated financial position, results of operations or cash flow of the Company.

ITEM 4. *Mine Safety Disclosures*

Not applicable.

PART II. OTHER INFORMATION

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

Price Range of Common Stock and Dividends

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

	Common Stock		Dividend
	High	Low	Declared
Year Ended December 31, 2012:			
Fourth Quarter	$ 21.66	$ 16.23	$ 0.0875
Third Quarter	$ 20.64	$ 16.62	$ 0.0875
Second Quarter	$ 23.69	$ 13.32	$ 0.0875
First Quarter	$ 26.09	$ 20.41	$ 0.0875
Year Ended December 31, 2011:			
Fourth Quarter	$ 29.87	$ 22.00	$ 0.0875
Third Quarter	$ 35.75	$ 25.54	$ 0.0875
Second Quarter	$ 34.70	$ 27.28	$ 0.0875
First Quarter	$ 35.95	$ 25.93	$ 0.0750

At February 12, 2013, there were approximately 2,250 holders of record of our common stock and approximately 375,500 beneficial owners.

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

In addition, our corporate revolving bank credit facility contains a restriction on our ability to declare and pay cash dividends on our common or preferred stock if an event of default has occurred. The certificates of designation for our preferred stock prohibit payment of cash dividends on our common stock unless we have declared and paid (or set apart for payment) full accumulated dividends on the preferred stock.

Unregistered Sales of Equity Securities and Use of Proceeds

The following table presents information about repurchases of our common stock during the quarter ended December 31, 2012:

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, 2012 through October 31, 2012	57,465	$	19.86	—	—
November 1, 2012 through November 30, 2012...	14,416	$	17.34	—	—
December 1, 2012 through December 31, 2012...	409,053	$	16.66	—	—
Total	480,934			—	—

(a) Reflects the surrender to the Company of shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) We make matching contributions to our 401(k) plan and deferred compensation plan using Chesapeake common stock that is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of Company contributions.

ITEM 6. *Selected Financial Data*

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2012, 2011, 2010, 2009 and 2008. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. The table should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* and our consolidated financial statements, including the notes, appearing in Items 7 and 8, respectively, of this report.

	Years Ended December 31,				
	2012	2011	2010	2009	2008
	($ in millions, except per share data)				
REVENUES:					
Natural gas, oil and NGL	$ 6,278	$ 6,024	$ 5,647	$ 5,049	$ 7,858
Marketing, gathering and compression	5,431	5,090	3,479	2,463	3,598
Oilfield services	607	521	240	190	173
Total Revenues	12,316	11,635	9,366	7,702	11,629
OPERATING EXPENSES:					
Natural gas, oil and NGL production	1,304	1,073	893	876	889
Production taxes	188	192	157	107	284
Marketing, gathering and compression	5,312	4,967	3,352	2,316	3,505
Oilfield services	465	402	208	182	143
General and administrative	535	548	453	349	377
Natural gas, oil and NGL depreciation, depletion and amortization	2,507	1,632	1,394	1,371	1,970
Depreciation and amortization of other assets	304	291	220	244	174
Impairment of natural gas and oil properties	3,315	—	—	11,000	2,800
Net (gains) losses on sales of fixed assets	(267)	(437)	(137)	38	—
Impairments of fixed assets and other	340	46	21	130	30
Employee retirement and other termination benefits	7	—	—	34	—
Total Operating Expenses	14,010	8,714	6,561	16,647	10,172
INCOME (LOSS) FROM OPERATIONS	(1,694)	2,921	2,805	(8,945)	1,457
OTHER INCOME (EXPENSE):					
Interest expense	(77)	(44)	(19)	(113)	(271)
Earnings (losses) on investments	(103)	156	227	(39)	(38)
Gains on sales of investments	1,092	—	—	—	—
Losses on purchases or exchanges of debt	(200)	(176)	(129)	(40)	(4)
Impairments of investments	—	—	(16)	(162)	(180)
Other income (expense)	8	23	16	11	27
Total Other Income (Expense)	720	(41)	79	(343)	(466)
INCOME (LOSS) BEFORE INCOME TAXES	(974)	2,880	2,884	(9,288)	991
INCOME TAX EXPENSE (BENEFIT):					
Current income taxes	47	13	—	4	423
Deferred income taxes	(427)	1,110	1,110	(3,487)	(36)
Total Income Tax Expense (Benefit)	(380)	1,123	1,110	(3,483)	387
NET INCOME (LOSS)	(594)	1,757	1,774	(5,805)	604
Net income attributable to noncontrolling interests	(175)	(15)	—	(25)	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(769)	1,742	1,774	(5,830)	604
Preferred stock dividends	(171)	(172)	(111)	(23)	(33)
Loss on conversion/exchange of preferred stock	—	—	—	—	(67)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (940)	$ 1,570	$ 1,663	$ (5,853)	$ 504

	Years Ended December 31,				
	2012	2011	2010	2009	2008
	($ in millions, except per share data)				
STATEMENT OF OPERATIONS DATA (continued):					
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ (1.46)	$ 2.47	$ 2.63	$ (9.57)	$ 0.94
Diluted	$ (1.46)	$ 2.32	$ 2.51	$ (9.57)	$ 0.93
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.35	$ 0.3375	$ 0.30	$ 0.30	$ 0.2925
CASH FLOW DATA:					
Cash provided by operating activities	$ 2,837	$ 5,903	$ 5,117	$ 4,356	$ 5,357
Cash used in investing activities	$ (4,984)	$ (5,812)	$ (8,503)	$ (5,462)	$ (9,965)
Cash provided by (used in) financing activities	$ 2,083	$ 158	$ 3,181	$ (336)	$ 6,356
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 41,611	$ 41,835	$ 37,179	$ 29,914	$ 38,593
Long-term debt, net of current maturities	$ 12,157	$ 10,626	$ 12,640	$ 12,295	$ 13,175
Total equity	$ 17,896	$ 17,961	$ 15,264	$ 12,341	$ 17,017

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

	Years Ended December 31,		
	2012	2011	2010
Net Production:			
Natural gas (bcf)	1,128.8	1,004.1	924.9
Oil (mmbbl)	31.3	17.0	10.9
NGL (mmbbl)	17.6	14.7	7.5
Natural gas equivalent (bcfe)[(a)]	1,422.1	1,194.2	1,035.2
Natural Gas, Oil and NGL Sales ($ in millions):			
Natural gas sales	$ 2,004	$ 3,133	$ 3,169
Natural gas derivatives – realized gains (losses)	328	1,656	1,982
Natural gas derivatives – unrealized gains (losses)	(331)	(669)	425
Total natural gas sales	2,001	4,120	5,576
Oil sales	2,829	1,523	822
Oil derivatives – realized gains (losses)	39	(60)	74
Oil derivatives – unrealized gains (losses)	857	(128)	(1,033)
Total oil sales	3,725	1,335	(137)
NGL sales	526	603	257
NGL derivatives – realized gains (losses)	(9)	(42)	—
NGL derivatives – unrealized gains (losses)	35	8	(49)
Total NGL sales	552	569	208
Total natural gas, oil and NGL sales	$ 6,278	$ 6,024	$ 5,647
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 1.77	$ 3.12	$ 3.43
Oil ($ per bbl)	$ 90.49	$ 89.80	$ 75.29
NGL ($ per bbl)	$ 29.89	$ 40.96	$ 34.38
Natural gas equivalent ($ per mcfe)	$ 3.77	$ 4.40	$ 4.10
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 2.07	$ 4.77	$ 5.57
Oil ($ per bbl)	$ 91.74	$ 86.25	$ 82.10
NGL ($ per bbl)	$ 29.37	$ 38.12	$ 34.38
Natural gas equivalent ($ per mcfe)	$ 4.02	$ 5.70	$ 6.09
Other Operating Income[(b)] ($ in millions):			
Marketing, gathering and compression net margin	$ 119	$ 123	$ 127
Oilfield services net margin	$ 142	$ 119	$ 32
Other Operating Income[(b)] ($ per mcfe):			
Marketing, gathering and compression net margin	$ 0.08	$ 0.10	$ 0.12
Oilfield services net margin	$ 0.10	$ 0.10	$ 0.03

	2012	2011	2010
	Years Ended December 31,		
Expenses ($ per mcfe):			
Natural gas, oil and NGL production	$ 0.92	$ 0.90	$ 0.86
Production taxes	$ 0.13	$ 0.16	$ 0.15
General and administrative expenses	$ 0.38	$ 0.46	$ 0.44
Natural gas, oil and NGL depreciation, depletion and amortization	$ 1.76	$ 1.37	$ 1.35
Depreciation and amortization of other assets	$ 0.21	$ 0.24	$ 0.21
Interest expense[c]	$ 0.06	$ 0.03	$ 0.08
Interest Expense ($ in millions):			
Interest expense	$ 84	$ 30	$ 99
Interest rate derivatives – realized (gains) losses	$ (1)	$ 7	$ (14)
Interest rate derivatives – unrealized (gains) losses	$ (6)	$ 7	$ (66)
Total interest expense	$ 77	$ 44	$ 19

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

(b) Includes revenue and operating costs and excludes depreciation and amortization of other assets. See *Depreciation and Amortization of Other Assets* under *Results of Operations* for details of the depreciation and amortization of other assets associated with our marketing, gathering and compression and oilfield services operating segments.

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

We are the second-largest producer of natural gas, a top 11 producer of liquids and the most active driller of wells in the U.S. We own interests in approximately 45,400 producing natural gas and oil wells that are currently producing approximately 3.9 bcfe per day, net to our interest. The Company has built a large resource base of onshore U.S. unconventional natural gas and liquids assets. Our core natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania; and the Barnett Shale in the Fort Worth Basin of north-central Texas. In addition, we have built leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas; the Utica Shale in Ohio and Pennsylvania; the Granite Wash, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas; and the Niobrara Shale in the Powder River Basin in Wyoming. We have also vertically integrated many of our operations and own substantial marketing, compression and oilfield services businesses.

Proved Reserves. The Company's December 31, 2012 estimated proved reserves were 15.690 tcfe, a decrease of 3.099 tcfe, or 17%, from 18.789 tcfe at year-end 2011. The decrease was primarily price related as natural gas prices in 2012 declined to the lowest levels in ten years. The 2012 proved reserve movement included 6.391 tcfe of extensions, downward revisions of 5.414 tcfe resulting from lower natural gas prices and 1.349 tcfe resulting from changes to previous estimates. In 2012, we produced 1.422 tcfe, acquired 42 bcfe and divested 1.347 tcfe of estimated proved reserves, including the disposition of 1.013 tcfe associated with the sale of our Permian Basin assets in September and October 2012.

Downward price revisions of 5.414 tcfe were the result of a decrease in natural gas prices used in estimating proved reserves as of December 31, 2012 by $1.36, or 33%, to $2.76 per mcf from $4.12 per mcf as of December 31, 2011, using the trailing 12-month average prices required by the SEC. The reserve reductions included the loss of significant proved undeveloped reserves, primarily in the Barnett Shale and the Haynesville Shale plays, for which future development is uneconomic at the natural gas prices used in the reserves estimates. As a result of lower estimated reserves as of September 30, 2012, we were required to impair the carrying value of our natural gas and oil properties and, if the trailing 12-month average natural gas, oil and NGL prices are lower in future periods, we could have additional impairments. An impairment of this type is a non-cash charge that does not impact our liquidity or our ability to comply with financial covenants. Future impairments of the carrying value of our natural gas and oil properties, if any, will be dependent on many factors, including natural gas, oil and NGL prices, production rates, levels of reserves, the evaluation of costs excluded from amortization, the timing and impact of asset sales, future development costs and service costs. We refer you to the risk factor "*Declines in the prices of natural gas and oil could result in a write-down of our asset carrying values"* included in Item 1A of this report and the discussion below of the full cost method of accounting under *Application of Critical Accounting Policies – Natural Gas and Oil Properties* in this Item 7. In addition, see *Natural Gas and Oil Properties* in Note 1 of the notes to our consolidated financial statements included in Item 8 of this report. The 1.349 tcfe downward revisions to previous estimates were primarily the result of altering our development plans as we made changes in rig allocations to shift rigs from natural gas to liquids-rich plays and to focus drilling on the core areas of our plays. See Note 10 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Production. Our 2012 production of 1.422 tcfe consisted of 1.129 tcf of natural gas (80% on a natural gas equivalent basis), 31.3 mmbbls of oil (13% on a natural gas equivalent basis) and 17.6 mmbbls of NGL (7% on a natural gas equivalent basis). Daily production for 2012 averaged 3.886 bcfe, an increase of 614 mmcfe, or 19%, over the 3.272 bcfe produced per day in 2011. During 2012, Chesapeake curtailed approximately 70 bcf of net natural gas production, or an average of approximately 190 mmcf per day of natural gas spread across the year. We undertook these curtailments primarily in the first half of 2012 in response to continued low natural gas prices. The curtailed volumes were located primarily in the Haynesville and Barnett shale plays.

In recognition of the value gap between liquids and natural gas prices, Chesapeake directed a significant portion of its technological and leasehold acquisition expertise during the past four years to identify, secure and commercialize new unconventional liquids-rich plays. This planned transition will result in a more balanced and, we believe, more profitable portfolio between natural gas and liquids. In 2012, our production of liquids averaged approximately 133,550 bbls per day, a 54% increase over the 2011 average, as a result of the increased development of our unconventional liquids-rich plays. We expect to increase our liquids production through our drilling activities by approximately 27% in 2013 compared to 2012.

Other Operating Segments. In addition to our exploration and production operating segment, we also have a marketing, gathering and compression operating segment and an oilfield services operating segment that we utilize as a financial and operational hedge against inflation and to help assure that we have access to quality services. In October 2011, we formally segregated our oilfield services businesses under our wholly owned subsidiary, COS, and its wholly owned subsidiary COO. COO's subsidiaries include a leading U.S. drilling contractor, oilfield trucking company, oilfield rental provider and a hydraulic fracturing business. Our oilfield services operating segment is separately capitalized, has its own revolving bank credit facility and COO issued senior notes in 2011. In September 2009, we formally segregated our midstream gathering services under a wholly owned subsidiary, Chesapeake Midstream Development, L.L.C. (CMD). During 2012, we sold the majority of our midstream business, including our investment in Access Midstream Partners, L.P. (NYSE:ACMP), as described under *Recent Sales - Midstream Sales* below. We have retained a minor portion of our midstream gathering business and still own significant marketing and compression operations businesses.

Sales. Our business strategy is to create value for investors by building, developing and now harvesting what we believe is the largest onshore natural gas and liquids-rich resource base in the U.S. After years of building our resource base, we are focused on developing the 10 plays where we have a #1 or #2 ownership position and selling assets (outright or through joint venture transactions) that are non-core or do not fit our long-term plans. During 2012, we completed sales of non-core natural gas and oil properties, our midstream business and preferred equity interests in a subsidiary for proceeds of approximately $11.6 billion. We have announced our intention to sell natural gas and oil properties, midstream and other assets for expected total proceeds of $4 - $7 billion in 2013. Our sales program, together with our forecasted operating cash flow and borrowings under our corporate revolving bank credit facility, are anticipated to fully fund the Company's 2013 capital expenditure program and further reduce the Company's long-term debt. We refer you to risks associated with our sales plans, as described in *Planned Sales* below.

Recent Developments

On January 29, 2013, Aubrey K. McClendon, our President, Chief Executive Officer (CEO) and a director, agreed to retire from the Company. Mr. McClendon will continue to serve as CEO, President and a director until the earlier of April 1, 2013 or the time at which his successor is appointed. Mr. McClendon's departure from the Company will be treated as a termination without cause under his employment agreement.

Also on January 29, 2013, the Compensation Committee of our Board of Directors approved retention awards for 14 of the Company's senior management team in the form of time-vested stock options to purchase an aggregate of 2.56 million shares of common stock. These awards, ranging from 150,000 to 360,000 stock options, have an exercise price equal to the closing price of the Company's common stock on the grant date, and vest one-third on each of the third, fourth and fifth anniversaries of the grant date. The options are subject to accelerated vesting if the executive is terminated (other than for cause) during the vesting period; however, no accelerated vesting will occur if the executive retires or voluntarily resigns prior to vesting.

On February 20, 2013, we announced that our Board of Directors had received the results of its previously announced review of the financing arrangements between Mr. McClendon (and the entities through which he participates in the Founder Well Participation Program (FWPP)) and third parties identified as having a financial relationship with us, as well as other matters. The review, which was led by the Audit Committee of the Board with the assistance of independent counsel retained by the independent members of the Board in April 2012, has been substantially completed. In connection with the review, millions of pages of documents were collected and reviewed and more than 50 interviews of Chesapeake and third-party personnel were conducted.

Among the transactions reviewed were the 2008-2012 financing arrangements between EIG Global Energy Partners (EIG) and affiliates of Mr. McClendon regarding financing of his participation in the FWPP, as well as the preferred stock investments by EIG in CHK Utica, L.L.C. and CHK Cleveland Tonkawa, L.L.C. See *Noncontrolling Interests* in Note 8 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the preferred stock investment transactions. The review of the financing arrangements did not reveal any improper benefit to Mr. McClendon or increased cost to the Company as a result of the overlap in the financial relationships.

The review also covered:

- other relationships in which both Mr. McClendon and the Company conducted business with the same financial institutions;
- the trading activities of the Heritage Hedge Fund (co-founded by Mr. McClendon) through 2007, when the Heritage Hedge Fund ceased operations; and
- other matters, including issues regarding administration of the FWPP, and a 1998 loan to Mr. McClendon by then Board member Frederick B. Whittemore.

Based on the documents reviewed and interviews conducted, no intentional misconduct by Mr. McClendon or any of the Company's management was found by the Board concerning these relationships and/or these transactions and issues.

We also announced on February 20, 2013 that our Board of Directors had concluded that the Company did not violate antitrust laws in connection with the acquisition of Michigan oil and gas rights in 2010. As described in Item 3 and in Note 4 of the notes to our consolidated financial statements included in Item 8 of this report, in June 2012 we received a subpoena duces tecum from the Antitrust Division, Midwest Field Office, of the United States Department of Justice, and demands for documents and information from state governmental agencies, investigating possible antitrust violations arising from 2010 leasing activities. The Board commenced its own investigation of these allegations in June 2012 and based its conclusion on a thorough review conducted independently by outside counsel and cooperation with the Department of Justice.

On February 25, 2013, we announced we had entered into an agreement whereby Sinopec International Petroleum Exploration and Production Corporation (Sinopec) will purchase a 50% undivided interest in 850,000 of our net oil and natural gas leasehold acres in the Mississippi Lime play in northern Oklahoma (425,000 acres net to Sinopec). The total consideration for the transaction will be $1.02 billion in cash, of which approximately 93% will be received upon closing. Payment of the remaining proceeds will be subject to certain customary title contingencies. Production from these assets (including Mississippi Lime and other formations), net to our interest and prior to Sinopec's purchase, averaged approximately 34 thousand barrels of oil equivalent per day in the 2012 fourth quarter and, as of December 31, 2012, there was approximately 140 million barrels of oil equivalent of net proved reserves associated with the assets. All future exploration and development costs in the joint venture will be shared proportionately between the parties with no drilling carries involved. As the operator of the project, we will conduct all leasing, drilling, completion, operations and marketing for the joint venture. The transaction is anticipated to be completed in the 2013 second quarter.

Recent Sales

An essential part of our business strategy in 2012 and 2013 is using the proceeds from sales to fund the capital expenditures needed to transition from a natural gas-focused drilling program to a liquids-focused drilling program and to reduce our indebtedness. Below we describe transactions completed in 2012 and the continuing benefits of our joint ventures which were completed prior to 2012.

Permian Basin. In September and October 2012, we sold the vast majority of our Permian Basin assets, representing approximately 6% of our total proved reserves as of June 30, 2012 and 6% of our 2012 second quarter net production, in three separate transactions for total net cash proceeds of approximately $3.091 billion. Approximately $466 million of additional consideration was withheld subject to certain title, environmental and other standard contingencies. Following the closing, we received approximately $84 million of such consideration, including $45 million received subsequent to December 31, 2012, and we expect to receive the majority of the remaining contingent amount in 2013. Of the total proceeds, we allocated approximately $42 million to our Permian Basin midstream and other fixed assets. The remaining proceeds were allocated to our Permian Basin natural gas and oil properties.

In September 2012, to facilitate our Permian Basin divestiture process, we purchased the remaining reserves from our Permian Basin volumetric production payment (VPP #7), originally entered into in June 2010, for $313 million. The reserves purchased totaled 28 bcfe and were subsequently sold to the buyers of our Permian Basin assets described above.

Chitwood Knox. In December 2012, we sold approximately 40,000 net acres of non-core leasehold in the Chitwood Knox play in Oklahoma for approximately $540 million in cash. The properties included approximately 13 mmcfe per day of current net production.

Non-Core Utica Shale. In August 2012, we sold approximately 72,000 net acres of non-core leasehold in the Utica shale play in Ohio to affiliates of EnerVest, Ltd. for approximately $358 million in cash.

Texoma Woodford. In April 2012, we sold approximately 60,000 net acres of leasehold in the Texoma Woodford play in Oklahoma to XTO Energy Inc., a subsidiary of Exxon Mobil Corporation (NYSE:XOM), for approximately $572 million in cash. The properties included approximately 25 mmcfe per day of current net production.

Under full cost accounting rules, we account for the sale of natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss. In conjunction with certain transactions, affiliates of Mr. McClendon sold interests in the same properties and on the same terms as those that applied to the interests sold by the Company, and proceeds were paid to the sellers based on their respective ownership. These interests were acquired through the FWPP, which provides Mr. McClendon a contractual right to participate and invest as a working interest owner (with up to a 2.5% working interest) in new wells drilled on the Company's leasehold through June 2014.

Midstream Sales. In June 2012, we sold all of our common and subordinated units representing limited partner interests in Chesapeake Midstream Partners, L.P., now named Access Midstream Partners, L.P. (NYSE:ACMP), and all of our limited liability company interests in the sole member of its general partner to funds affiliated with Global Infrastructure Partners (GIP) for cash proceeds of $2.0 billion. We recorded a $1.032 billion pre-tax gain associated with the transaction.

In December 2012, our wholly owned midstream subsidiary, CMD, sold its wholly owned subsidiary, Chesapeake Midstream Operating, L.L.C. (CMO), which held a substantial majority of our midstream business, to ACMP for cash proceeds of $2.16 billion, subject to post-closing adjustments. These midstream assets are located primarily in our Marcellus, Utica, Eagle Ford, Haynesville and Niobrara shale plays. The transaction with ACMP included new gathering and processing agreements covering acreage dedication areas in these plays. We recorded a $289 million pre-tax gain associated with this transaction. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of this transaction.

In November 2012, we sold our oil gathering business in the Eagle Ford Shale to Plains Pipeline, L.P. for cash consideration of approximately $115 million. Payment of an additional $10 million was subject to a closing contingency, and we received the additional proceeds subsequent to December 31, 2012. We recorded a $7 million pre-tax loss associated with this transaction in 2012 that will adjust to a $3 million pre-tax gain with the receipt of the $10 million contingency payment in 2013. In connection with the sale, we entered into new gathering and transportation agreements covering acreage dedication areas.

Cleveland Tonkawa Financial Transaction. We formed CHK Cleveland Tonkawa, L.L.C. (CHK C-T) in March 2012 to continue development of a portion of our natural gas and oil assets in our Cleveland and Tonkawa plays. CHK C-T is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including under our indentures. In exchange for all of the common shares of CHK C-T, we contributed to CHK C-T approximately 245,000 net acres of leasehold and existing wells within an area of mutual interest in the Cleveland and Tonkawa plays covering Ellis and Roger Mills counties in western Oklahoma. In March 2012, in a private placement, third-party investors contributed $1.25 billion in cash to CHK C-T in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest (ORRI) in the existing wells and up to 1,000 new net wells to be drilled on certain of our Cleveland and Tonkawa play leasehold. For further discussion, see *Noncontrolling Interests* in Note 8 of the notes to our consolidated financial statements included in Item 8 of this report.

Volumetric Production Payment (VPP). In March 2012, we monetized certain of our producing assets in the Anadarko Basin Granite Wash through a ten-year VPP for proceeds of approximately $744 million. The transaction included approximately 160 bcfe of proved reserves and approximately 125 mmcfe per day of net production at the time of the transaction. Chesapeake has retained drilling rights on the properties below currently producing intervals and outside of existing producing wellbores and we also retain all production beyond the specified volumes sold in the transaction. This transaction was our tenth VPP. The cash proceeds from this transaction were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. Other VPPs we completed in 2007 – 2011 are detailed in Note 11 of the notes to our consolidated financial statements included in Item 8 of this report.

Joint Ventures. As of December 31, 2012, we had entered into seven significant joint ventures with other leading energy companies pursuant to which we sold a portion of our leasehold, producing properties and other assets located in seven different resource plays and received cash of $7.1 billion and commitments for future drilling and completion cost carries of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all leasing, drilling, completion, operations and marketing activities for the project. The carry obligations paid by a joint venture partner are for a specified percentage of our drilling and completion cost obligations. In addition, a joint venture partner is responsible for its proportionate share of drilling and completion costs as a working interest owner. We bill our joint venture partners for their drilling carry obligations at the same time we bill them and other joint working interest owners for their share of drilling costs as they are incurred. The transactions are detailed below.

Primary Play	Joint Venture Partner[(a)]	Joint Venture Date	Interest Sold	Cash Proceeds Received at Closing	Total Drilling Carries	Total Cash and Drilling Carry Proceeds	Drilling Carries Remaining[(b)]
				($ in millions)			
Utica	TOT	December 2011	25.0%	$ 610	$ 1,422 [(c)]	$ 2,032	$ 1,153
Niobrara	CNOOC	February 2011	33.3%	570	697 [(d)]	1,267	463
Eagle Ford	CNOOC	November 2010	33.3%	1,120	1,080	2,200	—
Barnett	TOT	January 2010	25.0%	800	1,404 [(e)]	2,204	—
Marcellus	STO	November 2008	32.5%	1,250	2,125	3,375	—
Fayetteville	BP	September 2008	25.0%	1,100	800	1,900	—
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508 [(f)]	3,158	—
				$ 7,100	$ 9,036	$ 16,136	$ 1,616

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

(b) As of December 31, 2012.

(c) The Utica drilling carries cover 60% of our drilling and completion costs for Utica wells drilled and must be used by December 2018. We expect to fully utilize these drilling carry commitments prior to expiration. See *Drilling Commitments* in Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the Utica drilling carries.

(d) The Niobrara drilling carries cover 67% of our drilling and completion costs for Niobrara wells drilled and must be used by December 2014. We expect to fully utilize these drilling carry commitments prior to expiration.

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

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

The drilling and completion carries in our joint venture agreements allow us to reduce our finding costs. During 2012 and 2011, our drilling and completion costs included the benefit of approximately $784 million and $2.570 billion, respectively, of drilling and completion carries paid by our joint venture partners. Our drilling and completion costs in 2013 and 2014 will continue to be partially offset by the use of drilling and completion carries associated with our joint venture agreements. Once the remaining carries have been used, we anticipate our net drilling and completion costs will increase in the respective plays.

During 2012, we sold interests in additional leasehold we acquired in the Marcellus, Barnett and Utica shale plays to our joint venture partners TOT and STO for approximately $272 million pursuant to our joint venture agreements. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Planned Sales

We anticipate completing the sale of nearly all of our remaining midstream business, including our Mid-Continent gathering systems and other assets, in the 2013 first half.

In addition to the Mississippi Lime joint venture discussed under *Recent Developments*, we have other natural gas and oil assets currently for sale, including our northern Eagle Ford assets and various portions of our Marcellus and Utica leasehold in Pennsylvania and Ohio that we consider non-core.

We do not have binding agreements for all of our planned asset sales and our ability to consummate each of these transactions is subject to changes in market conditions and other factors beyond our control.

Liquidity and Capital Resources

Liquidity Overview

Our business is capital intensive. Historically, we have made capital expenditures that exceeded our cash flow from operations. We project that our capital expenditures will continue to exceed our operating cash flow in 2013, although by a significantly smaller amount as we continue our transition to an asset base more balanced between natural gas and oil from one primarily focused on natural gas and we shift to harvesting assets after approximately a decade of asset accumulation. We also expect to benefit from operating efficiencies associated with our strategy of developing the core of the core of our substantial leasehold position. During 2012, the combination of high capital expenditures and reduced cash flow as a result of low natural gas prices led to a spending "gap" that we filled with borrowings and proceeds from sales of assets that we determined were non-core or did not fit our long-term plans. We increased our debt, net of unrestricted cash, by approximately $2.058 billion, to $12.333 billion, in 2012.

As of December 31, 2012, we had approximately $4.338 billion in cash availability (defined as unrestricted cash on hand plus borrowing capacity under our revolving bank credit facilities) compared to $3.134 billion as of December 31, 2011. As of December 31, 2012, we had negative working capital of approximately $3.318 billion compared to negative working capital of approximately $3.905 billion as of December 31, 2011. Working capital deficits have existed largely because our capital spending generally has exceeded our cash flow from operations.

For 2013, we plan to fund capital expenditures with operating cash flow, borrowings under our revolving bank credit facilities and proceeds from asset sales. Our 2013 capital expenditure budget is approximately 50% less than our 2012 capital expenditures, and as operator of a substantial portion of our natural gas and oil properties under development, we have significant control and flexibility over the development plan and the associated timing, enabling us to expeditiously reduce at least a portion of our capital spending if needed. To mitigate our downside exposure to lower commodity prices, we have hedged approximately 72% of our forecasted 2013 natural gas, oil and NGL production revenue, including downside hedge protection on approximately 50% of our 2013 estimated natural gas production at an average price of $3.62 per mcf (most of these hedges were established subsequent to December 31, 2012) and 85% of our 2013 estimated oil production at an average price of $95.45 per bbl. Hedging allows us to reduce the effect of price volatility on our cash flows and earnings before interest, taxes, depreciation, depletion and amortization (EBITDA). Based on our forecasted operating cash flow for 2013, which takes into account our current hedges, and considering our 2013 forecasted capital expenditures, we are expecting a funding gap of approximately $4 billion. We believe we will have ample liquidity to fill the funding gap with borrowing capacity under our corporate revolving bank credit facility. However, we plan to offset the need to borrow under our corporate revolving bank credit facility with sales of certain of our natural gas and oil properties, midstream and other assets and expect those total proceeds to be $4 - $7 billion in 2013. Through February 2013, we have closed or have binding agreements on approximately $1.4 billion of asset sales. Asset sales are uncertain and subject to changes in market conditions and other factors beyond our control. Any remaining cash available after applying these proceeds to the deficit between capital expenditures and operating cash flow will be available to reduce our long-term debt.

As part of our sales planning and capital expenditure budgeting process, we closely monitor the resulting effects on the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our corporate revolving bank credit facility. While asset sales enhance our ability to reduce debt, sales of producing natural gas and oil properties may adversely affect the amount of cash flow and EBITDA we generate and reduce the amount and value of collateral available to secure our obligations, both of which can be exacerbated by low prices for our production. In September 2012, we obtained an amendment to our revolving bank credit facility agreement that relaxed the required indebtedness to EBITDA ratio for the quarter ended September 30, 2012 and the four subsequent quarters. See *Bank Credit Facilities - Corporate Credit Facility* below for discussion of the terms of the amendment. We would have been unable to meet the required ratio as of September 30, 2012 without this amendment primarily because the closing of certain asset sales transactions occurred in the fourth quarter and not in September as we had anticipated. As a result, without the amendment, we would have been unable to reduce our indebtedness sufficiently as of September 30, 2012 to maintain our covenant compliance. As of December 31, 2012, we were in compliance with the current covenants and would have also been in compliance with the more restrictive covenants that existed prior to the amendment. Failure to maintain compliance with the covenants of our revolving bank credit facility agreement could result in the acceleration of outstanding indebtedness under the facility and lead to cross defaults under our senior note and contingent convertible senior note indentures, hedge facility, equipment master lease agreements and term loan.

We expect to have adequate liquidity to repay $464 million of senior note indebtedness that matures in 2013. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties pursuant to various arrangements, agreements and investments described in *Contractual Obligations and Off-Balance Sheet Arrangements* below and in Note 4 of the notes to our consolidated financial statements included in Item 8 of this report, recognizing that we may be required to meet such commitments even if our business plan assumptions were to change due to circumstances beyond our control.

Based upon our capital expenditure budget, expected commodity prices (including the prices for our currently hedged production), our forecasted drilling and production, projected levels of indebtedness and binding purchase and sale agreements for certain future asset sales, we are projecting that we will be in compliance with the financial maintenance covenants of our corporate revolving bank credit facility, and we will have adequate liquidity, through 2013. We believe the assumptions underlying our budget for this period are reasonable and that we have adequate flexibility, including the ability to adjust discretionary capital expenditures and other spending, to adapt to potential negative developments if needed.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for 2012, 2011 and 2010. See *Recent Sales* above and Notes 8, 11 and 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the sales of natural gas and oil assets, sales of other assets and sales of preferred interests and noncontrolling interests in subsidiaries.

	2012	2011	2010
		($ in millions)	
Cash provided by operating activities[a]	$ 2,837	$ 5,903	$ 5,117
Sales of natural gas and oil assets:			
Permian Basin	3,130	—	—
Texoma	572	—	—
Chitwood Knox	540	—	—
Fayetteville Shale	—	4,270	—
TOT (Utica) joint venture	—	610	—
CNOOC (Niobrara) joint venture	—	553	—
CNOOC (Eagle Ford) joint venture	—	—	1,085
TOT (Barnett) joint venture[b]	—	425	853
Joint venture leasehold	272	511	440
Volumetric production payments	744	849	1,622
Other natural gas and oil properties	626	433	292
Total sales of natural gas, oil and other assets	5,884	7,651	4,292
Sales of other assets:			
Sale of CMO	2,160	—	—
Sale of AMS	—	879	—
Sale of Springridge gathering system	—	—	500
Proceeds from sales of other assets	332	433	383
Total proceeds from sales of other assets	2,492	1,312	883
Other sources of cash and cash equivalents:			
Sale of investment in ACMP	2,000	—	—
Sale of preferred interest and ORRI in CHK C-T	1,250	—	—
Sale of preferred interest and ORRI in CHK Utica	—	1,250	—
Sale of noncontrolling interest in Chesapeake Granite Wash Trust	—	410	—
Proceeds from investments	—	101	—
Proceeds from long-term debt	6,985	1,614	1,967
Proceeds from credit facility borrowings, net	—	—	1,814
Proceeds from issuance of preferred stock	—	—	2,562
Cash received from financing derivatives[c]	—	1,043	621
Other	84	341	20
Total other sources of cash and cash equivalents	10,319	4,759	6,984
Total sources of cash and cash equivalents	$ 21,532	$ 19,625	$ 17,276

(a) Includes cash settlements of derivative instruments classified as operating cash flows. Also includes cash distributions of $56 million, $85 million and $88 million in 2012, 2011 and 2010, respectively, from ACMP and its predecessor, and $28 million and $58 million in 2011 and 2010, respectively, from our equity investee, FTS International, Inc. and its predecessor.

(b) 2011 includes the $425 million acceleration of the payment of TOT's remaining drilling carry in exchange for a reduction in the obligation. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

(c) Reflects derivatives deemed to contain, for accounting purposes, a significant financing element at contract inception.

Cash flow from operations is a source of liquidity we use to fund capital expenditures, pay dividends and repay debt. Cash provided by operating activities was $2.837 billion in 2012 compared to $5.903 billion in 2011 and $5.117 billion in 2010. The decline in cash flow from operations from 2011 to 2012 is primarily the result of a decrease in the realized natural gas price (excluding the effect of unrealized gains or losses on derivatives) from $4.77 per mcf in 2011 to $2.07 per mcf in 2012. The increase in cash flow from operations from 2010 to 2011 is primarily the result of an increase in production of 159 bcfe. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items such as depreciation, depletion and amortization, impairments of natural gas and oil properties and other assets, deferred income taxes and mark-to-market changes in our derivative instruments. See the discussion below under *Results of Operations*.

The following table reflects the proceeds received from issuances of corporate securities in 2012, 2011 and 2010. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

	2012		2011		2010	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
			($ in millions)			
Senior notes	$ 1,300	$ 1,263	$ 1,650	$ 1,614	$ 2,000	$ 1,967
Term loans[a]	6,000	5,722	—	—	—	—
Convertible preferred stock	—	—	—	—	2,600	2,562
Total	$ 7,300	$ 6,985	$ 1,650	$ 1,614	$ 4,600	$ 4,529

(a) Includes principal amounts of $4.0 billion and $2.0 billion for our May 2012 term loans and November 2012 term loan, respectively. The entire principal amount of the May 2012 term loans was repaid in October and November 2012 without penalty.

Our $4.0 billion corporate revolving bank credit facility, our $500 million oilfield services revolving bank credit facility and cash and cash equivalents are other sources of liquidity. We use these revolving bank credit facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $20.318 billion and repaid $21.650 billion in 2012, borrowed $15.509 billion and repaid $17.466 billion in 2011 and borrowed $15.117 billion and repaid $13.303 billion in 2010 under our revolving bank credit facilities. Our corporate facility is secured by natural gas and oil proved reserves. A significant portion of our natural gas and oil reserves are currently unencumbered and therefore available to be pledged as additional collateral if needed to respond to borrowing base and collateral redeterminations our lenders might make in the future. We believe our borrowing capacity under this facility will not be reduced as a result of any such future redeterminations. Our oilfield services facility is secured by substantially all of our wholly owned oilfield services assets and is not subject to periodic borrowing base redeterminations. From September 2009 until June 2012, we also had a $600 million midstream revolving bank credit facility which we terminated in June 2012. Our revolving bank credit facilities are described below under *Bank Credit Facilities*.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for 2012, 2011 and 2010:

	2012	2011	2010
		($ in millions)	
Natural gas and oil expenditures:			
Drilling and completion costs[(a)]	$ (8,707)	$ (7,257)	$ (5,061)
Acquisitions of proved properties	(342)	(48)	(243)
Acquisitions of unproved properties	(2,043)	(4,296)	(6,015)
Geological and geophysical costs[(b)]	(193)	(210)	(181)
Interest capitalized on unproved properties	(806)	(630)	(687)
Total natural gas and oil expenditures	(12,091)	(12,441)	(12,187)
Other uses of cash and cash equivalents:			
Additions to other property and equipment	(2,651)	(2,009)	(1,326)
Acquisition of drilling company	—	(339)	—
Payments of credit facility borrowings, net	(1,332)	(1,957)	—
Cash paid to purchase debt	(4,000)	(2,015)	(3,434)
Dividends paid	(398)	(379)	(281)
Distributions to noncontrolling interest owners	(218)	(9)	—
Cash paid for financing derivatives[(c)]	(37)	—	—
Additions to investments	(395)	—	(134)
Other	(474)	(227)	(119)
Total uses of cash and cash equivalents	$ (21,596)	$ (19,376)	$ (17,481)

(a) Net of $784 million, $2.570 billion and $1.151 billion in drilling and completion carries received from our joint venture partners during 2012, 2011 and 2010, respectively.

(b) Includes related capitalized interest.

(c) Reflects derivatives deemed to contain, for accounting purposes, a significant financing element at contract inception.

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. Drilling and completion costs during 2012 reflected the impact of our deliberate transition to liquids-focused drilling and reduced natural gas drilling and a reduction in the amount of drilling and completion carries received from our joint venture partners. During the 2012 first quarter, our rig count was as high as 165 rigs as we were quickly ramping up our liquids-focused drilling while, at the same time, we were gradually ramping down drilling of natural gas wells. As of February 28, 2013, our rig count had been reduced to 83 operated rigs. Our natural gas drilling activities were sharply reduced in 2012, from 50 rigs at the beginning of the year to an average of 9 rigs in the fourth quarter. The 2012 drilling and completion expenditures also reflected significant well completion costs for natural gas wells that had been drilled, but not completed, in prior periods. These completions, which represented more than 60% of all natural gas wells we completed during 2012, enabled us to hold by production the related leasehold according to the terms of our leases. Approximately 75% of our unproved property leasehold acquisition costs of $2.043 billion during 2012 were focused on adding to our acreage in the Utica, Marcellus and Mid-Continent plays. Capital expenditures related to our midstream, oilfield services and other fixed assets of $2.651 billion during 2012 were primarily related to the expansion of our gathering systems and the growth of our oilfield services businesses, in particular the hydraulic fracturing line of business. We sold substantially all of our midstream business in December 2012.

In October and November 2012, we fully repaid the $4.0 billion May 2012 term loans for $4.0 billion with cash proceeds from asset sales and proceeds from the issuance of our November 2012 term loan. We recorded a loss of approximately $200 million with this repayment.

In 2011, we completed and settled tender offers to purchase $2.044 billion in principal amount of our senior notes and contingent convertible senior notes for $2.186 billion in cash, including approximately $171 million in cash premiums, primarily funded with a portion of the net proceeds we received from the sale of our Fayetteville Shale assets.

In 2010, we completed and settled tender offers to purchase $3.434 billion in principal amount of our senior notes for $3.434 billion in cash.

We paid dividends on our common stock of $227 million, $207 million and $189 million in 2012, 2011 and 2010, respectively. We paid dividends on our preferred stock of $171 million, $172 million and $92 million in 2012, 2011 and 2010, respectively. The increase in 2011 was due to the issuance of 2.6 million shares of preferred stock in 2010.

During 2012, we had net additions to investments of $395 million, including $109 million of additional investment in FTS International, Inc., $50 million of additional investment in Clean Energy Fuels Corp., $80 million of additional investment in Sundrop Fuels, Inc. and $220 million for three midstream investments that were sold in December 2012 as part of the sale of substantially all of our midstream business to ACMP. See Note 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of these investments.

Bank Credit Facilities

During 2012, we used three revolving bank credit facilities as sources of liquidity. In June 2012, we paid off and terminated our midstream credit facility. Our two remaining revolving bank credit facilities are described below.

	Corporate Credit Facility[(a)]	Oilfield Services Credit Facility[(b)]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$ 4,000	$ 500
Amount outstanding as of December 31, 2012	$ —	$ 418
Letters of credit outstanding as of December 31, 2012	$ 31	$ —

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.

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

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, our credit facilities do not contain provisions which would trigger an acceleration of amounts due under the respective facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Corporate Credit Facility. Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by proved reserves and bear interest at a variable rate. We were in compliance with all covenants under the amended agreement as of December 31, 2012. For further discussion on the terms of our corporate credit facility, see Note 3 of the notes to our consolidated financial statements included in Item 8 of this report.

As described above in *Liquidity Overview,* in September 2012, we entered into an amendment to the credit facility agreement, effective September 30, 2012. The amendment, among other things, adjusts our required indebtedness to EBITDA ratio covenant through the earlier of (a) December 31, 2013 and (b) the date on which we elect to reinstate the indebtedness to EBITDA ratio in effect prior to the amendment (in either case, the "Amendment Effective Period"). The amendment increased the maximum indebtedness to EBITDA ratio as of September 30, 2012 from 4.00 to 1.00 to 6.00 to 1.00 and revised the required ratio for the next four quarters as shown below. The ratio returns to 4.00 to 1.00 as of December 31, 2013 and thereafter.

Effective Date	Indebtedness to EBITDA Ratio
December 31, 2012	5.00 to 1.00
March 31, 2013	4.75 to 1.00
June 30, 2013	4.50 to 1.00
September 30, 2013	4.25 to 1.00

Our actual indebtedness to EBITDA ratio as of December 31, 2012 was approximately 3.91 to 1.00. The ratio compares consolidated indebtedness to consolidated EBITDA, both non-GAAP financial measures that are defined in the credit facility agreement, for the 12-month period ending on the measurement date. Consolidated indebtedness consists of outstanding indebtedness, less the cash and cash equivalents of Chesapeake and certain of our subsidiaries. Consolidated EBITDA consists of the net income of Chesapeake and certain of our subsidiaries, excluding income from investments and non-cash income plus interest expense, taxes, depreciation, amortization expense and other non-cash expenses, and is calculated on a pro forma basis to give effect to any acquisitions, divestitures or other changes.

The credit facility amendment increases the applicable margin by 0.25% for borrowings under the corporate credit facility on each day during the Amendment Effective Period when borrowings exceed 50% of the borrowing capacity and requires us to pay a fee to each lender in an amount equal to 0.05% of its revolving commitment if the Amendment Effective Period is in effect on June 30, 2013. Based on current commitment levels, this would result in an additional payment of $2 million. In addition, the amendment does not allow our collateral value securing the borrowings to be more than $75 million below the collateral value that was in effect as of September 30, 2012 during the Amendment Effective Period.

Oilfield Services Credit Facility. Our $500 million syndicated oilfield services revolving bank credit facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. The facility may be expanded from $500 million to $900 million at COO's option, subject to additional bank participation. Borrowings under the credit facility are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries for this facility, but they are unrestricted subsidiaries under Chesapeake's senior notes, contingent convertible senior notes, term loan and corporate revolving bank credit facility), and bear interest at a variable interest rate. For further discussion of the terms of our oilfield services credit facility, see Note 3 of the notes to our consolidated financial statements included in Item 8 of this report.

Midstream Credit Facility. Prior to June 15, 2012, we utilized a $600 million midstream syndicated senior secured revolving bank credit facility to fund capital expenditures to build natural gas gathering and other systems in support of our drilling program and for general corporate purposes associated with our midstream operations. With the anticipated sale of the substantial majority of our midstream business in the second half of 2012, on June 15, 2012, we paid off and terminated our midstream credit facility.

Hedging Facility

We have a multi-counterparty secured hedging facility with 17 counterparties that have committed to provide approximately 6.4 tcfe of hedging capacity for natural gas, oil and NGL price derivatives and 6.4 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.0 billion under the terms of the facility. For further discussion of the terms of our hedging facility, see Note 9 of the notes to our consolidated financial statements included in Item 8 of this report.

Term Loans

May 2012 Term Loans. In May 2012, we entered into $4.0 billion of unsecured term loans under a credit agreement that provided for term loans in an aggregate principal amount of $4.0 billion. The net proceeds of the term loans of approximately $3.789 billion after discount, customary fees and syndication costs were used to repay borrowings under our corporate revolving credit facility and for general corporate purposes. The term loans were issued at a discount of 3%, or $120 million, and the customary fees and syndication costs incurred were approximately $91 million. In October and November 2012, we used proceeds from asset sales and our new term loan (the November 2012 term loan described below) to fully repay the May 2012 term loans. We recorded $200 million of associated losses with the repayment, including $86 million of deferred charges and $114 million of debt discount.

November 2012 Term Loan. In November 2012, we established an unsecured five-year term loan credit facility in an aggregate principal amount of $2.0 billion for net proceeds of $1.935 billion (November 2012 term loan). Our obligations under the facility rank equally with our outstanding senior notes and contingent convertible senior notes and are unconditionally guaranteed on a joint and several basis by our direct and indirect wholly owned subsidiaries that are subsidiary guarantors under the indentures for such notes. Amounts borrowed under the new facility, which priced at 98% of par, bear interest at LIBOR plus 4.5%. The LIBOR rate is subject to a floor of 1.25% per annum. The new facility is non-callable in the first year but may be voluntarily repaid without penalty in the second and third years at par plus a specified call premium and may be voluntarily repaid at any time thereafter at par. We used the net proceeds of the new term loan to fully repay the remaining outstanding borrowings under our May 2012 term loans and to repay outstanding borrowings under the Company's corporate revolving bank credit facility. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities and the November 2012 term loan discussed above, our long-term debt consisted of the following as of December 31, 2012:

		December 31, 2012
		($ in millions)
7.625% senior notes due 2013[(a)]	$	464
9.5% senior notes due 2015		1,265
6.25% euro-denominated senior notes due 2017[(b)]		454
6.5% senior notes due 2017		660
6.875% senior notes due 2018		474
7.25% senior notes due 2018		669
6.625% senior notes due 2019[(c)]		650
6.775% senior notes due 2019		1,300
6.625% senior notes due 2020		1,300
6.875% senior notes due 2020		500
6.125% senior notes due 2021		1,000
2.75% contingent convertible senior notes due 2035[(d)]		396
2.5% contingent convertible senior notes due 2037[(d)]		1,168
2.25% contingent convertible senior notes due 2038[(d)]		347
Discount on senior notes[(e)]		(425)
Interest rate derivatives[(f)]		20
Total senior notes, net		10,242
Less current maturities of long-term debt[(a)]		(463)
Total long-term senior notes, net	$	9,779

(a) These senior notes are due July 2013. There is $1 million of discount associated with these notes.

(b) The principal amount shown is based on the exchange rate of $1.3193 to €1.00 as of December 31, 2012. See Note 9 of the notes to our consolidated financial statements included in Item 8 of this report for information on our related foreign currency derivatives.

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

(d) 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.

(e) Included in this discount is $376 million at December 31, 2012 associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

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

For further discussion and details regarding our senior notes, contingent convertible senior notes and COO senior notes, see Note 3 of the notes to our consolidated financial statements included in Item 8 of this report.

Credit Risk

Derivative instruments that enable us to manage our exposure to natural gas, oil and NGL prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. During the more than 15 years we have engaged in hedging activities, we have experienced a counterparty default only once (Lehman Brothers in September 2008), and the total loss recorded in that instance was immaterial. On December 31, 2012, our natural gas, oil and interest rate derivative instruments were spread among 12 counterparties. Additionally, the counterparties under our multi-counterparty secured hedging facility are required to secure their obligations in excess of defined thresholds. We use this facility for the majority of our natural gas, oil and NGL derivatives.

Our accounts receivable are primarily from purchasers of natural gas, oil and NGL ($1.457 billion at December 31, 2012) and exploration and production companies that own interests in properties we operate ($592 million at December 31, 2012). 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 2012, 2011 and 2010, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables.

Conversions and Exchanges of Contingent Convertible Senior Notes and Preferred Stock

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

Year	Contingent Convertible Senior Notes	Principal Amount	Number of Common Shares
		($ in millions)	(in thousands)
2010	2.25% due 2038	$ 11	299

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

Year of Conversion	Contingent Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares
		(in thousands)	
2011	5.75%	3	111
2010	5.0% (series 2005)	5	21

Contractual Obligations and Off-balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2012, these arrangements and transactions included (i) operating lease agreements, (ii) VPP obligations (to physically deliver and purchase volumes and pay related production expenses and taxes in the future), (iii) open purchase commitments, (iv) open delivery commitments, (v) open drilling commitments, (vi) undrawn letters of credit, (vii) open gathering and transportation commitments and (viii) various other commitments we enter into in the ordinary course of business that could result in a future cash obligation.

The table below summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2012.

	Payments Due By Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt:					
Principal	$ 13,065	$ 464	$ 1,661	$ 4,700	$ 6,240
Interest	5,058	767	1,392	1,204	1,695
Financing lease obligations and other[a]	798	17	37	34	710
Operating lease obligations[b]	768	181	320	229	38
Asset retirement obligations[c]	375	7	36	35	297
Purchase obligations[d]	18,811	1,781	3,869	3,817	9,344
Equity investment obligations	111	106	5	—	—
Unrecognized tax benefits[e]	214	—	—	214	—
Standby letters of credit	31	31	—	—	—
Other	111	22	30	17	42
Total contractual cash obligations[f]	$ 39,342	$ 3,376	$ 7,350	$ 10,250	$ 18,366

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

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

(c) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2012 balance sheet. See Note 16 of the notes to our consolidated financial statements included in Item 8 of this report for more information on our asset retirement obligations.

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

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

(f) Does not include our costs to produce reserves attributable to non-expense-bearing royalty and other interests in our properties, including VPPs, which are discussed below.

As the operator of the properties from which VPP volumes have been sold, we have the responsibility to bear the cost of producing the reserves attributable to such interests, which we include as a component of production expenses and production taxes in our consolidated statements of operations in the periods such costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining the cost center ceiling for impairment purposes and in determining our standardized measure. The amount of these production expenses and taxes, based on cost levels as of December

31, 2012 pursuant to SEC reporting requirements, was estimated to be approximately $954 million in total and $182 million for the next twelve months on an undiscounted basis and approximately $760 million and $173 million, respectively, on a discounted basis using an annual discount rate of 10%. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all. We have committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

See Notes 4, 11 and 13 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of commitments, VPPs and VIEs, respectively.

Hedging Activities

Natural Gas, Oil and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. 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, 2012, our natural gas and oil derivative instruments consisted of swaps, options, swaptions and basis protection swaps. Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* contains a description of each of these instruments and realized and unrealized gains and losses on natural gas, oil and NGL derivatives during 2012, 2011 and 2010. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

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

Mark-to-market positions under commodity derivative contracts fluctuate with commodity prices. As described under *Hedging Facility* in Item 7A, our secured multi-counterparty hedging facility allows us to minimize the potential liquidity impact of significant mark-to-market fluctuations in the value of such derivatives by pledging our proved reserves.

The estimated fair values of our natural gas, oil and NGL derivative contracts as of December 31, 2012 and 2011 are provided below. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* for additional information concerning the fair value of our natural gas, oil and NGL derivative instruments.

	December 31,	
	2012	2011
	($ in millions)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ 24	$ —
Natural gas call options	(240)	(284)
Natural gas basis protection swaps	(15)	(42)
Fixed-price oil swaps	68	15
Oil call options	(748)	(1,282)
Oil call swaptions	(13)	(53)
Fixed-price oil knockout swaps	—	7
Estimated fair value	$ (924)	$ (1,639)

Changes in the fair value of natural gas and oil derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of settled designated 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 ($179) million, ($162) million and ($156) million as of December 31, 2012, 2011 and 2010, respectively. Based upon the market prices at December 31, 2012, we expect to transfer to earnings approximately $20 million of net loss included in accumulated other comprehensive income during the next 12 months. A detailed explanation of accounting for natural gas, oil and NGL derivatives appears under *Application of Critical Accounting Policies - Hedging* elsewhere in this Item 7.

Interest Rate Derivatives

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

For interest rate derivative contracts designated as fair value hedges, changes in fair values of the derivatives are recorded on the consolidated balance sheets as assets or (liabilities), with corresponding offsetting adjustments to the debt's carrying value. Changes in the fair value of derivatives not designated as fair value hedges, which occur prior to their maturity (i.e., temporary fluctuations in mark-to-market values), are reported currently in the consolidated statements of operations as interest expense and characterized as unrealized gains (losses).

Gains or losses from interest rate derivative contracts are reflected as adjustments to interest expense on the consolidated statements of operations. The components of interest expense for the years ended December 31, 2012, 2011 and 2010 are presented in Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*, and a detailed explanation of accounting for interest rate derivatives appears under *Application of Critical Accounting Policies - Hedging* elsewhere in this Item 7.

Foreign Currency Derivatives

On December 6, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. A detailed explanation of accounting for foreign currency derivatives appears under *Application of Critical Accounting Policies - Hedging* elsewhere in this Item 7.

Results of Operations

General. For the year ended December 31, 2012, Chesapeake had a net loss of $594 million, or $1.46 per diluted common share, on total revenues of $12.316 billion. This compares to net income of $1.757 billion, or $2.32 per diluted common share, on total revenues of $11.635 billion during the year ended December 31, 2011, and net income of $1.774 billion, or $2.51 per diluted common share, on total revenues of $9.366 billion during the year ended December 31, 2010. The decrease in net income from 2011 to 2012 is primarily driven by a $2.022 billion after-tax impairment of natural gas and oil properties recorded in the 2012 third quarter. See *Impairment of Natural Gas and Oil Properties* below.

Natural Gas, Oil and NGL Sales. During 2012, natural gas, oil and NGL sales were $6.278 billion compared to $6.024 billion in 2011 and $5.647 billion in 2010. In 2012, Chesapeake produced and sold 1.422 tcfe at a weighted average price of $4.02 per mcfe, compared to 1.194 tcfe produced and sold in 2011 at a weighted average price of $5.70 per mcfe and 1.035 tcfe in 2010 at a weighted average price of $6.09 per mcfe (weighted average prices exclude the effect of unrealized gains on derivatives of $561 million, unrealized losses on derivatives of $789 million and unrealized losses of $657 million in 2012, 2011 and 2010, respectively). The decrease in price received per mcfe in 2012 compared to 2011 resulted in a decrease in revenues of $2.397 billion and increased production resulted in a $1.300 billion increase in revenues, for a total decrease in revenues of $1.097 billion (excluding unrealized gains or losses on natural gas, oil and NGL derivatives). The increase in production from period to period was primarily generated through the drillbit.

For 2012, we realized an average price per mcf of natural gas of $2.07, compared to $4.77 in 2011 and $5.57 in 2010 (weighted average prices exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $91.74, $86.25 and $82.10 in 2012, 2011 and 2010, respectively. NGL prices realized per barrel (excluding unrealized gains or losses on derivatives) were $29.37, $38.12 and $34.38 in 2012, 2011 and 2010, respectively. Realized gains from our natural gas, oil and NGL derivatives resulted in a net increase in natural gas, oil and NGL revenues of $358 million, or $0.25 per mcfe, in 2012, a net increase of $1.554 billion, or $1.30 per mcfe, in 2011 and a net increase of $2.056 billion, or $1.99 per mcfe, in 2010. See Item 7A for a complete listing of all of our derivative instruments as of December 31, 2012.

A change in natural gas, oil and NGL prices has a significant impact on our revenues and cash flows. Assuming the 2012 production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2012 revenues and cash flows of approximately $113 million and $110 million, respectively, and an increase or decrease of $1.00 per barrel of liquids sold would result in an increase or decrease in 2012 revenues and cash flows of approximately $49 million and $47 million, respectively, without considering the effect of hedging activities.

The following tables show our production and average sales prices received by operating division for 2012, 2011 and 2010:

2012

	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	611.2	1.65	1.8	95.45	1.5	28.35	631.1	44	1.94
Northern	205.1	2.16	14.6	88.74	10.8	28.40	357.7	25	5.72
Eastern[c]	260.1	1.94	0.5	78.67	1.7	39.19	273.1	20	2.23
Western[d]	52.4	0.92	14.4	91.92	3.6	30.60	160.2	11	9.24
Total[e]	1,128.8	1.77	31.3	90.45	17.6	29.89	1,422.1	100%	3.77

2011

	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	554.7	2.83	0.1	108.15	1.1	36.63	561.8	47	2.89
Northern	258.2	3.55	10.2	90.03	10.6	40.26	383.0	32	5.90
Eastern[c]	135.8	3.27	0.3	79.90	1.2	55.44	144.8	12	3.69
Western[d]	55.4	3.58	6.4	89.68	1.8	37.46	104.6	9	8.05
Total[e]	1,004.1	3.12	17.0	89.90	14.7	40.96	1,194.2	100%	4.40

2010

	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	418.6	2.97	0.1	82.79	0.7	27.82	423.5	42	2.99
Northern	368.8	3.71	7.4	75.11	6.3	34.84	451.3	43	4.76
Eastern[c]	74.1	3.91	0.2	66.41	0.3	35.17	76.7	7	4.07
Western[d]	63.4	1.25	3.2	76.07	0.1	32.04	83.7	8	6.23
Total[e]	924.9	3.43	10.9	75.29	7.4	34.38	1,035.2	100%	4.10

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

(b) Our Barnett Shale production is concentrated in urban areas where the cost to develop the necessary infrastructure to gather and deliver the natural gas to intrastate pipelines significantly exceeds the cost of similar infrastructure in non-urban areas. Additionally, the rapid development of the Barnett Shale required the construction of new pipelines to provide an adequate market for these new gas reserves. In order to support the timely construction of these new pipelines, we entered into firm transportation contracts that have resulted in lower natural gas price realizations in the Barnett Shale than in our other major natural gas plays.

(c) Our Eastern division primarily includes the Marcellus Shale, which held approximately 23% of our estimated proved reserves by volume as of December 31, 2012. Production for the Marcellus Shale for the years ended 2012, 2011 and 2010 was 243.3 bcfe, 121.1 bcfe and 52.9 bcfe, respectively.

(d) Our Western division primarily includes the Eagle Ford Shale, which held approximately 21% of our estimated proved reserves by volume as of December 31, 2012. Production for the Eagle Ford Shale for the years ended 2012, 2011 and 2010 was 84.3 bcfe, 21.3 bcfe and 2.3 bcfe, respectively.

As the Eagle Ford Shale continues to be a developing play where additional infrastructure is being added to meet the growing production, we experienced lower natural gas price realizations in 2012 as a result of higher transportation costs compared to more developed plays.

(e) 2012, 2011 and 2010 production reflects various asset sales. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for information on our natural gas and oil property divestitures.

Our average daily production of 3.886 bcfe for 2012 consisted of 3.084 bcf of natural gas (80% on a natural gas equivalent basis) and approximately 133,550 bbls of liquids, consisting of approximately 85,420 bbls of oil (13% on a natural gas equivalent basis) and approximately 48,130 bbls of NGL (7% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 12%, our year-over-year growth rate of oil production was 84% and our year-over-year growth rate of NGL production was 19%. Because of the value gap between natural gas and liquids prices, as liquids production has increased as a percentage of our total production the percentage of revenue generated through the sale of liquids production has increased substantially. Our percentage of unhedged revenues from natural gas, oil and NGL is shown in the following table.

	2012	2011	2010
Natural gas	37%	60%	75%
Oil	53%	29%	19%
NGL	10%	11%	6%
Total	100%	100%	100%

Marketing, Gathering and Compression Sales and Expenses. Marketing, gathering and compression sales and expenses consist of third-party revenue and expenses related to our marketing, gathering and compression operations. Marketing, gathering and compression activities are performed by Chesapeake primarily for owners in Chesapeake-operated wells. Chesapeake recognized $5.431 billion in marketing, gathering and compression sales in 2012 with corresponding expenses of $5.312 billion, for a net margin before depreciation of $119 million. See *Depreciation and Amortization of Other Assets* below for the depreciation and amortization recorded on our marketing, gathering and compression assets. This compares to sales of $5.090 billion and $3.479 billion, expenses of $4.967 billion and $3.352 billion and margins before depreciation of $123 million and $127 million in 2011 and 2010, respectively. In 2012 and 2011, Chesapeake realized an increase in marketing, gathering and compression sales and expenses primarily due to an increase in third-party marketing volumes. These increases were offset by lower margins per mcfe as a result of certain marketing arrangements whereby we resold natural gas and NGL at marginally lower market prices as compared to the contract price purchases of the natural gas and NGL. We sold substantially all of our gathering business in the 2012 fourth quarter which will have a future impact on our marketing, gathering and compression sales and expenses. Our gathering business provided approximately $51 million, $44 million and $52 million of the total marketing, gathering and compression net margin, or 43%, 36% and 41%, in 2012, 2011 and 2010, respectively.

Oilfield Services Revenues and Expenses. Oilfield services consist of third-party revenue and expenses related to our oilfield services operations. Chesapeake recognized $607 million in oilfield services revenues in 2012 with corresponding expenses of $465 million, for a net margin before depreciation of $142 million. See *Depreciation and Amortization of Other Assets* below for the depreciation and amortization recorded on our oilfield services assets. This compares to revenue of $521 million and $240 million, expenses of $402 million and $208 million and a net margin before depreciation of $119 million and $32 million in 2011 and 2010, respectively. Oilfield services revenues, expenses and margins have increased as our oilfield services business has grown, in addition to an increase in service rates throughout 2011 and 2012. These increases were offset by losses recognized in 2012 related to certain consolidated investments. Our oilfield services segment was negatively impacted by impairments and early lease termination payments in 2012. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Natural Gas, Oil and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $1.304 billion in 2012, compared to $1.073 billion and $893 million in 2011 and 2010, respectively. On a unit-of-production basis, production expenses were $0.92 per mcfe in 2012 compared to $0.90 and $0.86 per mcfe in 2011 and 2010, respectively. The per unit expense increase in 2012 was primarily the result of a new fee retroactively imposed in Pennsylvania on spud wells, which had a $15 million, or $0.01 per mcfe effect, in addition to an overall increase in field rates and the lifting costs associated with VPP production for VPP #10 and #9 completed in March 2012 and May 2011, respectively. The per unit increase in 2011 was primarily the result of the sale of our Fayetteville Shale producing wells, which were high volume wells with lower per unit costs. Production expenses in 2012, 2011 and 2010 included approximately $220 million, $234 million and $139 million, or $0.15, $0.20 and $0.13 per mcfe, respectively, associated with VPP production volumes.

The following table shows our production expenses by operating division and our ad valorem tax expenses for 2012, 2011 and 2010:

	2012		2011		2010	
	Production Expenses	$/mcfe	Production Expenses	$/mcfe	Production Expenses	$/mcfe
	($ in millions, except per unit)					
Southern	$ 375	0.59	$ 334	0.59	$ 262	0.62
Northern	492	1.38	384	1.01	349	0.77
Eastern	137	0.50	134	0.93	117	1.52
Western	226	1.41	159	1.52	100	1.22
	1,230	0.87	1,011	0.85	828	0.80
Ad valorem tax	74	0.05	62	0.05	65	0.06
Total	$ 1,304	0.92	$ 1,073	0.90	$ 893	0.86

Production Taxes. Production taxes were $188 million in 2012 compared to $192 million in 2011 and $157 million in 2010. On a unit-of-production basis, production taxes were $0.13 per mcfe in 2012 compared to $0.16 per mcfe in 2011 and $0.15 in 2010. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas, oil and NGL prices are higher. The $4 million decrease in production taxes in 2012 was primarily due to the decrease from 2011 to 2012 of the unhedged price of our production from $4.40 to $3.77 per mcfe, offset by an increase in production of 228 bcfe. The $35 million increase in production taxes in 2011 was primarily due to an increase in production of 159 bcfe and an increase in the unhedged price of our production from $4.10 to $4.40 per mcfe. Production taxes in 2012, 2011 and 2010 included approximately $20 million, $34 million and $26 million, or $0.01, $0.03 and $0.02 per mcfe, respectively, associated with VPP production volumes.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties and other property, plant and equipment (see Note 10 of the notes to our consolidated financial statements included in Item 8 of this report), were $535 million in 2012, $548 million in 2011 and $453 million in 2010. General and administrative expenses were $0.38, $0.46 and $0.44 per mcfe for 2012, 2011 and 2010, respectively. The per unit expense decrease in 2012 was primarily due to an increase in production of 228 bcfe. The actual and per unit expense increase in 2011 was primarily due to the Company's continued growth resulting in higher payroll and associated costs. Included in general and administrative expenses is stock-based compensation of $71 million in 2012, $92 million in 2011 and $84 million in 2010. Restricted stock expense is based on the price of our common stock on the grant date of the award.

Our stock-based compensation for employees and non-employee directors during 2012, 2011 and 2010 was in the form of restricted stock. Equity compensation helps offset the fact that we do not have a pension plan. Employee restricted stock awards generally vest over a period of four years. Our annual non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 1 and Note 8 of the notes to our consolidated financial statements included in Item 8 of this report provides additional detail on the accounting for and reporting of our stock-based compensation.

Chesapeake follows the full cost method of accounting under which all costs associated with natural gas and oil property acquisition, divestiture, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, divestiture, drilling and completion activities and do not include any costs related to production, general corporate overhead or similar activities. In addition, we capitalize internal costs that can be identified with the construction of certain of our property, plant and equipment. We capitalized $434 million, $432 million and $378 million of internal costs in 2012, 2011 and 2010, respectively, directly related to our natural gas and oil property acquisition, divestiture, drilling and completion efforts and the construction of our property, plant and equipment.

Natural Gas, Oil and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas, oil and NGL properties was $2.507 billion, $1.632 billion and $1.394 billion during 2012, 2011 and 2010, respectively. The $875 million and $238 million increases in 2012 and 2011 are primarily the result of a 19% and 15% increase in production in 2012 and 2011, respectively, the 2012 decrease in Barnett Shale and Haynesville Shale proved undeveloped reserves primarily as a result of downward price revisions, and the higher costs of liquids-rich plays compared to natural gas plays as we shift to a more liquids-focused strategy. 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 $1.76, $1.37 and $1.35 in 2012, 2011 and 2010, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $304 million in 2012, compared to $291 million in 2011 and $220 million in 2010. Depreciation and amortization of other assets was $0.21, $0.24 and 0.21 per mcfe in 2012, 2011 and 2010, respectively. The per unit decrease in 2012 is primarily due to an increase in production in 2012 and the result of classifying approximately $1.8 billion of midstream assets as held for sale from June 30, 2012 until they were sold in December 2012. Assets classified as held for sale are not subject to depreciation. See Note 1 of the notes to our consolidated financial statements included in Item 8 of this report for information regarding our assets held for sale.

Property and equipment costs are depreciated on a straight-line basis and are depreciated over the estimated useful lives of the assets. To the extent company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as drilling and completion costs. The following table shows the estimated useful life of our assets and depreciation expense by asset class for 2012, 2011 and 2010:

	December 31,			Useful
	2012	2011	2010	Life
		($ in millions)		(in years)
Oilfield services equipment[a]	$ 61	$ 52	$ 14	3 - 15
Natural gas gathering systems and treating plants[b]	46	58	55	20
Buildings and improvements	42	34	28	10 - 39
Natural gas compressors[b]	26	18	13	3 - 20
Computers and office equipment	45	40	43	3 - 7
Vehicles	52	46	31	0 - 5
Other	32	43	36	2 - 20
Total depreciation and amortization of other assets	$ 304	$ 291	$ 220	

(a) Included in our oilfield services operating segment.

(b) Included in our marketing, gathering and compression operating segment.

Impairment of Natural Gas and Oil Properties. In the third quarter of 2012, we reported a non-cash impairment charge on our natural gas and oil properties of $3.315 billion, primarily resulting from a 10% decrease in trailing 12-month average first-day-of-the-month natural gas prices as of September 30, 2012 compared to June 30, 2012, and the impairment of certain undeveloped leasehold, primarily in the Williston and DJ Basins. We account for our natural gas and oil properties using the full cost method of accounting, which limits the amount of costs we can capitalize and requires us to write off these costs if the carrying value of natural gas and oil assets in the evaluated portion of our full cost pool exceeds the sum of the present value of expected future net cash flows of proved reserves using a 10% pre-tax discount rate based on pricing and cost assumptions prescribed by the SEC and the present value of certain natural gas and oil derivative instruments. See Note 1 and Note 10 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our impairment of natural gas and oil properties.

Gains on Sales of Fixed Assets. In 2012, net gains on sales of fixed assets were $267 million compared to net gains of $437 million in 2011 and net gains of $137 million in 2010. The sale of our midstream subsidiary, CMO, in 2012 generated a $289 million gain; the sale of our midstream subsidiary, AMS, in 2011 generated a $439 million gain; and the sale of our Springridge gas gathering system in 2010 generated a $157 million gain. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our gains and losses on sales and impairments of fixed assets and other.

Impairments of Fixed Assets and Other. In 2012, impairments of fixed assets and other were $340 million compared to $46 million in 2011 and $21 million in 2010. In 2012 and 2011, we recognized $248 million and $3 million of impairment losses, respectively, primarily associated with an office building and surface land located in our Barnett Shale operating area. Also in 2012, we negotiated the purchase from various lessors of 25 rigs previously sold in our sale leaseback transactions for an aggregate purchase price of $61 million, of which $25 million was deemed to be early lease termination costs and recognized as an impairment. In addition, in 2012, we recognized $35 million of impairment losses on certain of our owned drilling rigs and related equipment due to the expectation that these particular drilling rigs would have insufficient cash flow to recover their carrying value. We had additional impairments of $32 million, $42 million and $21 million in 2012, 2011 and 2010, respectively, on midstream and other assets. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our gains and losses on sales and impairments of fixed assets and other.

Employee Retirement and Other Termination Benefits. We recorded $7 million of employee retirement and other termination benefits in 2012 primarily related to reducing our Barnett Shale operations, the sale of our Permian Basin assets and charges related to our voluntary separation plan. See Note 21 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our voluntary separation plan.

Interest Expense. Interest expense was $77 million in 2012 compared to $44 million in 2011 and $19 million in 2010 as follows:

	Years Ended December 31,		
	2012	2011	2010
		($ in millions)	
Interest expense on senior notes	$ 732	$ 653	$ 718
Interest expense on credit facilities	70	70	61
Interest expense on term loans	173	—	—
Realized (gains) losses on interest rate derivatives	(1)	7	(14)
Unrealized (gains) losses on interest rate derivatives	(6)	7	(66)
Amortization of loan discount, issuance costs and other	89	39	36
Capitalized interest	(980)	(732)	(716)
Total interest expense	$ 77	$ 44	$ 19
Average senior notes borrowings	$ 10,487	$ 9,373	$ 10,345
Average term loans borrowings	$ 2,096	$ —	$ —

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.06 per mcfe in 2012 compared to $0.03 per mcfe in 2011 and $0.08 in 2010.

Earnings (Losses) on Investments. Losses on investments were $103 million in 2012, compared to earnings on investments of $156 million in 2011 and earnings on investments of $227 million in 2010. The 2012 loss related to our equity in the net losses of certain investments, primarily FTS International, Inc. (FTS). The 2011 earnings related to our equity in the net income of certain investments, primarily ACMP and FTS. The 2010 earnings consisted of $106 million related to our equity in the net income of certain investments and $121 million related to the initial public offering by ACMP and a private offering of common stock by Chaparral Energy, Inc., which represented our proportionate share of the excess of offering proceeds over our carrying value.

Gains on Sales of Investments. In 2012, we sold all of our common and subordinated units representing limited partner interests in Chesapeake Midstream Partners, L.P., now named Access Midstream Partners, L.P. (NYSE:ACMP), and all of our limited liability company interests in the sole member of its general partner to funds affiliated with Global Infrastructure Partners for cash proceeds of $2.0 billion. We recorded a $1.032 billion gain associated with the transaction. Also in 2012, we sold our investment in Glass Mountain Pipeline, LLC for cash proceeds of $99 million. We recorded a $62 million gain associated with the transaction.

Losses on Purchases or Exchanges of Debt. In October and November 2012, we used $4.0 billion in proceeds from asset sales and our November 2012 term loan discussed above to fully repay the May 2012 term loans. We recorded $200 million of associated losses with the repayment, including $86 million of deferred charges and $114 million of debt discount.

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

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

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

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

Impairment of Investments. We recorded $16 million of impairments of certain investments in 2010. Each of our investees was impacted by the dramatic slowing of the worldwide economy and the credit markets in 2009 and 2010. The economic weakness resulted in significantly reduced natural gas and oil prices which led to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized that an other than temporary impairment had occurred on certain investments.

Other Income. Other income was $8 million, $23 million and $16 million in 2012, 2011 and 2010, respectively. The 2012 income consisted of $1 million of interest income and $7 million of miscellaneous income. The 2011 income consisted of $3 million of interest income and $20 million of miscellaneous income. The 2010 income consisted of $8 million of interest income and $8 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $380 million in 2012 compared to income tax expense of $1.123 billion in 2011 and income tax expense of $1.110 billion in 2010. Our effective income tax rate was 39% in both 2012 and 2011 and 38.5% in 2010. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences.

Net Income Attributable to Noncontrolling Interests. In 2012, Chesapeake recorded $175 million of net income attributable to noncontrolling interests related to third-party ownership in CHK Utica, CHK C-T, the Chesapeake Granite Wash Trust and our consolidated investments in Wireless Seismic, Inc. and Big Star Crude Company, L.L.C. CHK Utica and the Chesapeake Granite Wash Trust were formed in the fourth quarter of 2011 and CHK C-T was formed in the first quarter of 2012. We began consolidating our investment in Wireless Seismic, Inc. and Big Star Crude Company, L.L.C. in the fourth quarter of 2012. In 2011, Chesapeake recorded $15 million of net income attributable to noncontrolling interests related to third-party ownership in CHK Utica and the Chesapeake Granite Wash Trust.

Application of Critical Accounting Policies

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

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

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

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

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

We review the carrying value of our natural gas and oil properties under the SEC's full cost accounting rules 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 natural gas and oil cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating estimated future net revenues, current prices are calculated as the unweighted arithmetic average of natural gas and oil prices on the first day of each month within the 12-month period prior to the ending date of the quarterly period. Costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives designated as cash flow hedges.

Two primary factors impacting this test are reserve levels and natural gas and oil prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. See *Natural Gas and Oil Properties* in Note 1 of the notes to our consolidated financial statements included in Item 8 of this report for further information on the full cost method of accounting.

Derivatives. Chesapeake uses commodity price and financial risk management instruments to mitigate a portion of our exposure to price fluctuations in natural gas and oil prices, changes in interest rates and foreign exchange rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of commodity derivative contracts are reflected in natural gas, oil and NGL sales, and results of interest rate and foreign exchange rate hedging contracts are reflected in interest expense. The changes in the fair value of derivative instruments not qualifying, or not elected, for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within natural gas, oil and NGL sales or interest expense. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative is deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statements of cash flows.

Accounting guidance for derivative instruments and hedging activities establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheets as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as natural gas, oil and NGL cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings as natural gas, oil and NGL sales. Any change in the fair value resulting from ineffectiveness is recognized immediately in natural gas, oil and NGL sales. For interest rate derivative instruments designated as fair value hedges, changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings as interest expense. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. See *Hedging Activities* above and Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* for additional information regarding our hedging activities.

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

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

Due to the volatility of natural gas, oil and NGL 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, 2012, 2011 and 2010, the fair value of our derivatives were liabilities of $979 million, $1.719 billion and $761 million, respectively.

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

VIEs that are not consolidated because we are not the primary beneficiary. We continually monitor both consolidated and unconsolidated VIEs to determine if any events have occurred that could cause the primary beneficiary to change. See Note 13 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of VIEs.

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 sheets. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent Chesapeake establishes a valuation allowance or increases or decreases this allowance in a period, we must include an expense or reduction of expense within the tax provision in the consolidated statement of operations.

Under accounting guidance for income taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (i) the more positive evidence is necessary and (ii) the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion or all of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years;
- whether the carryforward period is so brief that it would limit realization of the tax benefit;
- future sales and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures; and
- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

If (i) natural gas and oil prices were to decrease significantly below present levels (and if such decreases were considered other than temporary), (ii) exploration, drilling and operating costs were to increase significantly beyond current levels, or (iii) we were confronted with any other significantly negative evidence pertaining to our ability to realize our NOL carryforwards prior to their expiration, we may be required to provide a valuation allowance against our deferred tax assets. As of December 31, 2012, we had deferred tax assets of $1.566 billion.

Accounting guidance for recognizing and measuring uncertain tax positions prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. Based on this guidance, we regularly analyze tax positions taken or expected to be taken in a tax return based on the threshold condition prescribed. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. We accrue interest related to these uncertain tax positions which is recognized in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses. Additional information about uncertain tax positions appears in Note 5 of the notes to our consolidated financial statements included in Item 8 of this report.

Disclosures About Effects of Transactions with Related Parties

Chief Executive Officer

As of December 31, 2012 and 2011, we had accrued accounts receivable from our Chief Executive Officer, Aubrey K. McClendon, of $23 million and $45 million, respectively, representing joint interest billings from December 2012 and 2011 related to Mr. McClendon's participation in Company wells pursuant to the FWPP. These amounts were invoiced and timely paid in the following month. Since Chesapeake was founded in 1989, Mr. McClendon has acquired working interests in virtually all of our natural gas and oil properties by participating in our drilling activities under the terms of his employment agreement and the FWPP and predecessor participation arrangements provided for in Mr. McClendon's employment agreements. On April 30, 2012, the Company's Board of Directors and Mr. McClendon agreed to the early termination of the FWPP on June 30, 2014, 18 months before the end of the 10-year term approved by our shareholders in June 2005. Under the FWPP, 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. In conjunction with certain sales of natural gas and oil properties by the Company, affiliates of Mr. McClendon have sold interests in the same properties and on the same terms as those that applied to the interests sold by the Company, and proceeds were paid to the sellers based on their respective ownership.

On December 31, 2008, we entered into a new five-year employment agreement with Mr. McClendon that contained a one-time well cost incentive award to him. The total cost of the award to Chesapeake was $75 million plus employment taxes in the amount of approximately $1 million. The incentive award was subject to a clawback equal to any unvested portion of the award if during the initial five-year term of the employment agreement, Mr. McClendon resigned from the Company or was terminated for cause by the Company. We are recognizing the incentive award as general and administrative expense over the five-year vesting period for the clawback resulting in an expense of approximately $15 million per year beginning in 2009. The net incentive award after deduction of applicable withholding and employment taxes of approximately $44 million was fully applied against costs attributable to interests in Company wells acquired by Mr. McClendon or his affiliates under the FWPP. On January 29, 2013, the Company announced that Mr. McClendon had agreed to retire from the Company on the earlier to occur of April 1, 2013 or the time at which his successor is appointed. Mr. McClendon's participation rights under the FWPP are expected to continue through the expiration of the FWPP on June 30, 2014, and the incentive award clawback applicable to 2013 will not apply. See Note 21 for additional information on the terms of his separation from the Company.

In 2011, Chesapeake entered into a license and naming rights agreement with The Professional Basketball Club, LLC (PBC) for the arena in downtown Oklahoma City. PBC is the owner of the Oklahoma City Thunder basketball team, a National Basketball Association franchise and the arena's primary tenant. Mr. McClendon has a 19.2% equity interest in PBC. Under the terms of the agreement, Chesapeake has committed to pay fees ranging from $3 million to $4 million per year through 2023 for the arena naming rights and other associated benefits. In addition, since 2008, Chesapeake has been a founding sponsor of the Oklahoma City Thunder, initially under successive one-year contracts. In 2011, it entered into a 12-year sponsorship agreement, committing to pay an average annual fee of $3 million for advertising, use of an arena suite and other benefits. Chesapeake also has committed to purchase tickets to all 2012-2013 home games. In 2012 and 2011, the Company paid PBC approximately $7 million and $6 million, respectively, for naming rights fees, sponsorship fees and game tickets, and for 2013, the amount payable for such 2012-2013 season fees and tickets is approximately $3 million, not including any amounts for playoff tickets.

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

Other Related Parties

During 2012 and 2011, our formerly 46%-owned affiliate, ACMP, provided natural gas gathering and treating services to us in the ordinary course of business. We are party to various agreements pursuant to which we support ACMP and for which we are reimbursed. During 2012 and 2011, our transactions with ACMP included the following:

	Years Ended December 31,	
	2012	2011
	($ in millions)	
Amounts paid to ACMP:		
Gas gathering fees[(a)]	$ 624	$ 469
Amounts received from ACMP:		
Compressor rentals	80	60
Inventory purchases	91	93
Other services provided	88	91
Total amounts received from ACMP	$ 259	$ 244

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

As of December 31, 2012 and 2011, we had net receivables from ACMP of $5 million and $2 million, respectively. In addition, in 2012 and 2011, we sold natural gas gathering systems and related equipment to ACMP. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

During 2012, 2011 and 2010, our 30%-owned affiliate, FTS, provided us hydraulic fracturing and other services in the ordinary course of business. During 2012, 2011 and 2010, we paid FTS $-480million, $369 million and $89 million, respectively, for these services. As well operators, we are reimbursed by other working interest owners through the joint interest billing process for their proportionate share of these costs. In addition, during 2012 we purchased $73 million of equipment from FTS. As of December 31, 2012, 2011 and 2010, we owed $42 million, $115 million and $30 million, respectively, to FTS for services provided and not yet paid.

Recently Issued and Proposed Accounting Standards

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

In February 2013, the FASB issued guidance on disclosure of information about changes in accumulated other comprehensive income balances by component and significant items reclassified out of accumulated other comprehensive income. The new requirements include disclosing significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, if required to be reclassified to net income in their entirety. Other items will be cross-referenced to other required disclosures that provide additional information about those amounts. The guidance is effective for interim and annual periods beginning after December 15, 2012. This guidance will not have an impact on our financial position or results of operations.

In December 2011, the FASB issued guidance on disclosure of information about offsetting and related arrangements to enable users of a company's financial statements to understand the effect of those arrangements on its financial position. In January 2013, the FASB issued additional guidance to clarify the scope of disclosures about offsetting and related arrangements noting this guidance only applies to derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with specific criteria contained in other guidance or subject to a master netting arrangement or similar agreement. Both standards are effective for annual reporting periods beginning on or after January 1, 2013. This guidance will not have an impact on our financial position or results of operations.

Forward-Looking Statements

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Forward-looking statements give our current expectations or forecasts of future events. They include estimates of natural gas and oil reserves, expected natural gas, oil and NGL production and future expenses, estimated operating costs, assumptions regarding future natural gas, oil and NGL prices, planned drilling activity and drilling and completion capital expenditures (including the use of joint venture drilling carries), and anticipated sales, as well as statements concerning anticipated cash flow and liquidity, covenant compliance, debt reduction, business strategy and other plans and objectives for future operations. Pending sales transactions are subject to closing conditions and may not be completed in the time frame anticipated. We do not have binding agreements for all of our planned asset sales. Our ability to consummate each of these transactions is subject to changes in market conditions and other factors. If one or more of the transactions is not completed in the anticipated time frame, or at all, or for less proceeds than anticipated, our ability to fund budgeted capital expenditures and reduce our indebtedness as planned could be adversely affected. For sales transactions that have closed, we may not be able to satisfy all the requirements necessary to receive proceeds subject to title and other contingencies. 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 our 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, oil and NGL 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 sales, 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 amount and timing of development expenditures;
- inability to generate profits or achieve targeted results in our development and exploratory drilling and well operations;
- leasehold terms expiring before production can be established;
- hedging activities resulting in lower prices realized on natural gas, oil and NGL sales and the need to secure hedging liabilities;
- drilling and operating risks, including potential exposure to environmental liabilities;
- changes in legislation and regulation adversely affecting our industry and our business;
- general economic conditions negatively impacting us and our business counterparties;
- oilfield services shortages, pipeline and gathering system capacity constraints and transportation interruptions that could adversely affect our cash flow;
- losses possible from pending or future litigation and governmental proceedings; and
- cyber attacks targeting our systems and infrastructure adversely impacting our operations.

We caution you not to place undue reliance on the forward-looking statements contained in this report, which speak only as of the filing date, 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 SEC that attempt to advise interested parties of the risks and factors that may affect our business.

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

Natural Gas, Oil and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. 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 prices to be received for our production. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for attempting to mitigate exposure to adverse natural gas, oil and NGL price changes is to hedge into strengthening natural gas and oil futures markets when prices reach levels that management believes are either unsustainable for the long term, have material downside risk in the short term or provide reasonable rates of return on our invested capital. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas trends, natural gas and oil storage inventory levels, industry decline rates for base production and weather trends.

We use a wide range of derivative instruments to achieve our risk management objectives, including swaps, options and swaptions. All of these are described in more detail below. We typically use swaps for a large portion of the natural gas and oil volume we hedge. Swaps are used when the price level is acceptable. We also sell calls, taking advantage of market volatility for a portion of our projected production volumes. We do this when we would be satisfied to sell our production at the price being capped by the call strike price or believe it would be more likely than not that the future natural gas or oil price will stay below the call strike price plus the premium we will receive. In the second half of 2011 and in 2012, we bought natural gas and oil calls to, in effect, lock in sold call positions. Due to lower natural gas, oil and NGL prices, we were able to achieve this at a low cost to us. We deferred the payment of the premium on these trades to the related month of production being hedged. At times, we have taken advantage of attractive strip prices in out-years and sold natural gas and oil call options to our counterparties in exchange for near-term natural gas swaps with fixed prices above the then current market price. This effectively allowed us to sell out-year volatility through call options at terms acceptable to us in exchange for natural gas swaps with fixed prices in excess of the market price for natural gas at that time. In the fourth quarter of 2011, we entered into oil swaps that can be extended at the option of the counterparty. This allows us to receive a higher fixed price on these swaps than what the market would have offered without such an option. Some of our derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception and the cash settlements associated with these instruments are classified as financing cash flows in the accompanying consolidated statement of cash flows.

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

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

We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been partially mitigated under our secured hedging facility which requires counterparties to post collateral if their obligations to Chesapeake are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. See Note 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the fair value measurements associated with our derivatives.

As of December 31, 2012, our natural gas and oil derivative instruments consisted of the following:

- *Swaps*: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
- *Options*: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call options, no payment is due from either party.
- *Swaptions:* Chesapeake sells call swaptions to counterparties that allow them, on a specific date, to extend an existing fixed-price swap for a certain period of time.
- *Basis protection Swaps*: These instruments are arrangements that guarantee a price differential to NYMEX from a specified delivery point. Our natural gas basis protection swaps typically have negative differentials to NYMEX. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. Our oil basis protection swaps 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.

As of December 31, 2012, we had the following open natural gas and oil derivative instruments:

	Volume	Weighted Average Price			Designated	Fair
		Fixed	Call	Differential	Hedge	Value
	(tbtu)		(per mmbtu)			($ in millions)
Natural Gas:						
Swaps:						
Q1 2013	24	$ 3.90	$ —	$ —	No	$ 13
Q2 2013	25	3.90	—	—	No	11
Call Options (sold):						
Q1 2013	44	—	6.39	—	No	—
Q2 2013	67	—	6.39	—	No	—
Q3 2013	68	—	6.39	—	No	(1)
Q4 2013	68	—	6.39	—	No	(1)
2014	330	—	6.43	—	No	(17)
2015	226	—	6.31	—	No	(29)
2016	279	—	6.72	—	No	(63)
2017 – 2020	114	—	10.92	—	No	(14)
Call Options (bought)[(a)]:						
Q1 2013	(44)	—	6.39	—	No	(3)
Q2 2013	(67)	—	6.39	—	No	(3)
Q3 2013	(68)	—	6.39	—	No	(2)
Q4 2013	(68)	—	6.39	—	No	(1)
2014	(330)	—	6.43	—	No	(23)
2015	(226)	—	6.31	—	No	(53)
2016	(200)	—	6.02	—	No	(30)
Basis Protection Swaps:						
2013	44	—	—	(0.21)	No	(1)
2014	28	—	—	(0.32)	No	(4)
2015	31	—	—	(0.34)	No	(3)
2016 – 2022	8	—	—	(1.02)	No	(7)
Total Natural Gas						$ (231)

	Volume	Weighted Average Price			Designated	Fair
		Fixed	Call	Differential	Hedge	Value
	(mmbbl)		(per bbl)			($ in millions)
Oil:						
Swaps:						
Q1 2013	5.9	$ 95.79	$ —	$ —	No	$ 20
Q2 2013	6.9	95.95	—	—	No	17
Q3 2013	7.0	95.88	—	—	No	15
Q4 2013	6.9	95.83	—	—	No	18
2014 – 2015	1.4	90.11	—	—	No	(2)
Call Options (sold):						
Q1 2013	4.8	—	94.74	—	No	(17)
Q2 2013	4.8	—	94.74	—	No	(30)
Q3 2013	4.9	—	94.74	—	No	(39)
Q4 2013	4.9	—	94.74	—	No	(44)
2014	16.9	—	96.92	—	No	(152)
2015	24.7	—	100.45	—	No	(225)
2016	18.9	—	104.71	—	No	(158)
2017	5.3	—	83.50	—	No	(86)
Call Options (bought)[b]:						
Q1 2013	(2.3)	—	90.80	—	No	(7)
Q2 2013	(2.3)	—	90.80	—	No	(1)
Q3 2013	(2.3)	—	90.80	—	No	3
Q4 2013	(2.3)	—	90.80	—	No	6
2014	(2.2)	—	94.91	—	No	2
Basis Protection Swaps:						
2013........................	5.5	—	—	13.20	No	—
Call Swaptions:						
2014	2.9	106.69	—	—	No	(9)
2015	2.4	106.61	—	—	No	(4)
Total Oil						$ (693)
Total Natural Gas and Oil						$ (924)

(a) Included in the fair value are deferred premiums of $11 million, $41 million, $82 million and $84 million which we will realize in 2013, 2014, 2015 and 2016, respectively.

(b) Included in the fair value are deferred premiums of $81 million and $19 million which we will realize in 2013 and 2014, respectively.

In addition to the open derivative positions disclosed above, at December 31, 2012, we had $171 million of net hedging gains related to settled trades for future production periods that will be recorded within natural gas, oil and NGL sales as realized gains (losses) as they are transferred from either accumulated other comprehensive income or unrealized gains (losses) in the month of related production based on the terms specified in the original contract as noted below.

	December 31, 2012
	($ in millions)
Q1 2013	16
Q2 2013	35
Q3 2013	31
Q4 2013	22
2014	(165)
2015	216
2016 – 2022	16
Total	$ 171

The table below reconciles the changes in fair value of our natural gas, oil and NGL derivatives during the years ended December 31, 2012, 2011 and 2010. Of the $924 million fair value liability as of December 31, 2012, $48 million related to contracts maturing in the next 12 months and $876 million related to contracts maturing after 12 months. All open derivative instruments as of December 31, 2012 are expected to mature by December 31, 2022.

	2012	2011	2010
	($ in millions)		
Fair value of contracts outstanding, as of January 1	$ (1,639)	$ (649)	$ 21
Change in fair value of contracts	657	664	995
Fair value of new contracts when entered into	174	(347)	(581)
Contracts realized or otherwise settled	(72)	(478)	(1,691)
Fair value of contracts when closed	(44)	(829)	607
Fair value of contracts outstanding, as of December 31	$ (924)	$ (1,639)	$ (649)

The change in natural gas, oil and NGL prices during the year ended December 31, 2012 decreased the liability of our derivative instruments by $657 million. This gain is recorded in natural gas, oil and NGL sales. We entered into new contracts which were in an asset position of $174 million. We settled contracts that were in an asset position for $72 million and we closed out contracts that were in an asset position for $44 million. The realized gain is recorded in natural gas, oil and NGL 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 recognized in natural gas, oil and NGL sales as unrealized gains (losses). Realized gains (losses) consist of settled contracts related to the production periods being reported. Unrealized gains (losses) consist of both temporary fluctuations in the mark-to-market values and settled values related to future production periods of derivatives not designated as cash flow hedges. As of December 31, 2012, we did not have any natural gas or oil derivatives that were designated as cash flow hedges.

The components of natural gas, oil and NGL sales for 2012, 2011 and 2010 are presented below.

	Years Ended December 31,		
	2012	2011	2010
		($ in millions)	
Natural gas, oil and NGL sales	$ 5,359	$ 5,259	$ 4,248
Realized gains (losses) on natural gas, oil and NGL derivatives	358	1,554	2,056
Unrealized gains (losses) on natural gas, oil and NGL derivatives	561	(782)	(634)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	—	(7)	(23)
Total natural gas, oil and NGL sales	$ 6,278	$ 6,024	$ 5,647

Interest Rate Risk

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

	Years of Maturity						
	2013	2014	2015	2016	2017	Thereafter	Total
				($ in millions)			
Liabilities:							
Debt – fixed rate[(a)]	$ 464	$ —	$ 1,661	$ —	$ 2,282	$ 6,240	$ 10,647
Average interest rate	7.63%	—%	7.89%	—%	4.40%	6.44%	6.28%
Debt – variable rate[(b)]	$ —	$ —	$ —	$ 418	$ 2,000	$ —	$ 2,418
Average interest rate	—%	—%	—%	2.95%	5.75%	—%	5.27%

(a) This amount does not include the discount included in debt of $425 million and interest rate derivatives of $20 million.

(b) This amount does not include the discount included in debt of $40 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 indebtedness is fixed rate and, therefore, does not expose us to the risk of fluctuations in earnings or cash flow due to changes in market interest rates. However, changes in interest rates do affect the fair value of our fixed-rate debt.

Interest Rate Derivatives

To mitigate a portion of our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives. As of December 31, 2012, our interest rate derivative instruments consisted of one type of instrument:

- *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.

As of December 31, 2012, the following interest rate derivatives were outstanding:

	Notional Amount	Weighted Average Rate: Fixed	Weighted Average Rate: Floating[(a)]	Fair Value Hedge	Net Premiums	Fair Value
	($ in millions)				($ in millions)	
Floating to Fixed:						
Swaps						
Mature 2014 – 2015	$ 1,050	2.13%	1 – 6 mL	No	—	(35)
					$ —	$ (35)

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

In addition to the open derivative positions disclosed above, at December 31, 2012 we had $75 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains (losses) as they are transferred from either our senior note liability or unrealized interest expense gains (losses) over the next nine-year term of the related senior notes.

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, 2012, 2011 and 2010 are presented below.

	Years Ended December 31, 2012	2011	2010
		($ in millions)	
Interest expense on senior notes	$ 732	$ 653	$ 718
Interest expense on credit facilities	70	70	61
Interest expense on term loans	173	—	—
Realized (gains) losses on interest rate derivatives	(1)	7	(14)
Unrealized (gains) losses on interest rate derivatives	(6)	7	(66)
Amortization of loan discount, issuance costs and other	89	39	36
Capitalized interest	(980)	(732)	(716)
Total interest expense	$ 77	$ 44	$ 19

Foreign Currency Derivatives

In December 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound cross currency swaps for the same principal amount. As a result, we reclassified a loss of $38 million from accumulated other comprehensive income to the consolidated statement of operations, $20 million of which related to the unwound notional amount and was included in losses on purchases or exchanges of debt, and $18 million of which related to future interest associated with the unwound principal and was included in interest expense. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay Chesapeake €11 million and Chesapeake pays the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €344 million and Chesapeake will pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swaps, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swaps are designated as cash flow hedges. The fair values of the cross currency swaps are recorded on the consolidated balance sheet as a liability of $20 million at December 31, 2012. The euro-denominated debt in long-term debt has been adjusted to $454 million at December 31, 2012 using an exchange rate of $1.3193 to €1.00.

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

INDEX TO FINANCIAL STATEMENTS
CHESAPEAKE ENERGY CORPORATION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management has performed an assessment of the effectiveness of the Company's internal control over financial reporting and has determined the Company's internal control over financial reporting was effective as of December 31, 2012.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2012 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
President and Chief Executive Officer

/s/ DOMENIC J. DELL'OSSO, JR.
Domenic J. Dell'Osso, Jr.
Executive Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, 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.

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

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

/s/ PricewaterhouseCoopers LLP
Tulsa, Oklahoma
March 1, 2013

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIEs)	$ 287	$ 351
Restricted cash	111	44
Accounts receivable	2,245	2,505
Short-term derivative assets	58	13
Deferred income tax asset	90	139
Other current assets	153	125
Current assets held for sale	4	—
Total Current Assets	2,948	3,177
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full cost accounting:		
Evaluated natural gas and oil properties ($488 and $498 attributable to our VIEs)	50,172	41,723
Unevaluated properties	14,755	16,685
Natural gas gathering systems and treating plants	—	1,455
Oilfield services equipment	2,130	1,632
Other property and equipment	3,778	3,555
Total Property and Equipment, at Cost	70,835	65,050
Less: accumulated depreciation, depletion and amortization (($58) and ($6) attributable to our VIEs)	(34,302)	(28,290)
Property and equipment held for sale, net	634	—
Total Property and Equipment, Net	37,167	36,760
LONG-TERM ASSETS:		
Investments	728	1,531
Long-term derivative assets	2	—
Other long-term assets	766	367
TOTAL ASSETS	$ 41,611	$ 41,835
CURRENT LIABILITIES:		
Accounts payable	$ 1,710	$ 3,311
Short-term derivative liabilities ($4 and $9 attributable to our VIEs)	105	191
Accrued interest	226	183
Current maturities of long-term debt, net	463	—
Other current liabilities ($21 and $23 attributable to our VIEs)	3,741	3,397
Current liabilities held for sale	21	—
Total Current Liabilities	6,266	7,082
LONG-TERM LIABILITIES:		
Long-term debt, net	12,157	10,626
Deferred income tax liabilities	2,807	3,484
Long-term derivative liabilities ($3 and $10 attributable to our VIEs)	934	1,541
Asset retirement obligations	375	323
Other long-term liabilities	1,176	818
Total Long-Term Liabilities	17,449	16,792
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 7,251,515 shares outstanding	3,062	3,062
Common stock, $0.01 par value, 1,000,000,000 shares authorized: 666,467,664 and 660,888,159 shares issued	7	7
Paid-in capital	12,293	12,146
Retained earnings	437	1,608
Accumulated other comprehensive income (loss)	(182)	(166)
Less: treasury stock, at cost; 2,147,724 and 1,552,533 common shares	(48)	(33)
Total Chesapeake Stockholders' Equity	15,569	16,624
Noncontrolling interests	2,327	1,337
Total Equity	17,896	17,961
TOTAL LIABILITIES AND EQUITY	$ 41,611	$ 41,835

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2012	2011	2010
	($ in millions, except per share data)		
REVENUES:			
Natural gas, oil and NGL	$ 6,278	$ 6,024	$ 5,647
Marketing, gathering and compression	5,431	5,090	3,479
Oilfield services	607	521	240
Total Revenues	12,316	11,635	9,366
OPERATING EXPENSES:			
Natural gas, oil and NGL production	1,304	1,073	893
Production taxes	188	192	157
Marketing, gathering and compression	5,312	4,967	3,352
Oilfield services	465	402	208
General and administrative	535	548	453
Natural gas, oil and NGL depreciation, depletion and amortization	2,507	1,632	1,394
Depreciation and amortization of other assets	304	291	220
Impairment of natural gas and oil properties	3,315	—	—
Net gains on sales of fixed assets	(267)	(437)	(137)
Impairments of fixed assets and other	340	46	21
Employee retirement and other termination benefits	7	—	—
Total Operating Expenses	14,010	8,714	6,561
INCOME (LOSS) FROM OPERATIONS	(1,694)	2,921	2,805
OTHER INCOME (EXPENSE):			
Interest expense	(77)	(44)	(19)
Earnings (losses) on investments	(103)	156	227
Gains on sales of investments	1,092	—	—
Losses on purchases or exchanges of debt	(200)	(176)	(129)
Impairments of investments	—	—	(16)
Other income	8	23	16
Total Other Income (Expense)	720	(41)	79
INCOME (LOSS) BEFORE INCOME TAXES	(974)	2,880	2,884
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	47	13	—
Deferred income taxes	(427)	1,110	1,110
Total Income Tax Expense (Benefit)	(380)	1,123	1,110
NET INCOME (LOSS)	(594)	1,757	1,774
Net income attributable to noncontrolling interests	(175)	(15)	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(769)	1,742	1,774
Preferred stock dividends	(171)	(172)	(111)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (940)	$ 1,570	$ 1,663
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ (1.46)	$ 2.47	$ 2.63
Diluted	$ (1.46)	$ 2.32	$ 2.51
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.35	$ 0.3375	$ 0.30
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	643	637	631
Diluted	643	752	706

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2012	2011	2010
		($ in millions)	
NET INCOME (LOSS)	$ (594)	$ 1,757	$ 1,774
Other comprehensive income (loss), net of income tax:			
Unrealized gain (loss) on derivative instruments, net of income taxes of $4 million, $137 million and $129 million	6	224	212
Reclassification of gain on settled derivative instruments, net of income taxes of ($10) million, ($139) million and ($298) million	(17)	(225)	(491)
Ineffective portion of derivatives designated as cash flow hedges, net of income taxes of $0, $3 million and $9 million	—	4	14
Unrealized gain (loss) on investments, net of income taxes of ($4) million, ($1) million and ($3) million	(5)	(1)	(5)
Other comprehensive income (loss)	(16)	2	(270)
COMPREHENSIVE INCOME (LOSS)	(610)	1,759	1,504
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(175)	(15)	—
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ (785)	$ 1,744	$ 1,504

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2012	2011	2010
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ (594)	$ 1,757	$ 1,774
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	2,811	1,923	1,614
Deferred income tax expense (benefit)	(427)	1,110	1,110
Unrealized (gains) losses on derivatives	(567)	796	592
Stock-based compensation	120	153	147
Gains on sales of fixed assets	(267)	(437)	(137)
Impairments of fixed assets and other	316	46	21
Impairment of natural gas and oil properties	3,315	—	—
(Gains) losses on investments	164	(41)	(107)
Gains on sales of investments	(1,092)	—	—
Impairment of investments	—	—	16
Losses on purchases or exchanges of debt	200	5	29
Other	74	(3)	110
Increase in accounts receivable and other assets	(68)	(530)	(769)
Increase (decrease) in accounts payable, accrued liabilities and other	(1,148)	1,124	717
Cash provided by operating activities	2,837	5,903	5,117
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and completion costs	(8,930)	(7,467)	(5,242)
Acquisitions of proved and unproved properties	(3,161)	(4,974)	(6,945)
Proceeds from divestitures of proved and unproved properties	5,884	7,651	4,292
Additions to other property and equipment	(2,651)	(2,009)	(1,326)
Proceeds from sales of other assets	2,492	1,312	883
Proceeds from (additions to) investments	(395)	101	(134)
Proceeds from sale of midstream investment	2,000	—	—
Acquisition of drilling company	—	(339)	—
Increase in restricted cash	(222)	(44)	—
Other	(1)	(43)	(31)
Cash used in investing activities	(4,984)	(5,812)	(8,503)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from credit facilities borrowings	20,318	15,509	15,117
Payments on credit facilities borrowings	(21,650)	(17,466)	(13,303)
Proceeds from issuance of term loans, net of discount and offering costs	5,722	—	—
Proceeds from issuance of senior notes, net of discount and offering costs	1,263	1,614	1,967
Proceeds from issuance of preferred stock, net of offering costs	—	—	2,562
Cash paid to purchase debt	(4,000)	(2,015)	(3,434)
Cash paid for common stock dividends	(227)	(207)	(189)
Cash paid for preferred stock dividends	(171)	(172)	(92)
Cash (paid) received on financing derivatives	(37)	1,043	621
Proceeds from sales of noncontrolling interests	1,077	1,348	—
Proceeds from other financings	257	300	—
Distributions to noncontrolling interest owners	(218)	(9)	—
Net increase (decrease) in outstanding payments in excess of cash balance	(172)	353	20
Other	(79)	(140)	(88)
Cash provided by financing activities	2,083	158	3,181
Net increase (decrease) in cash and cash equivalents	(64)	249	(205)
Cash and cash equivalents, beginning of period	351	102	307
Cash and cash equivalents, end of period	$ 287	$ 351	$ 102

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

	Years Ended December 31,		
	2012	2011	2010
	($ in millions)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF NET CASH PAYMENTS (REFUNDS) FOR:			
Interest, net of capitalized interest	$ —	$ —	11
Income taxes, net of refunds received	$ 44	$ (25)	(291)

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

Dividends payable on our common and preferred stock were $101 million, $99 million and $90 million as of December 31, 2012, 2011 and 2010, respectively.

In 2012, 2011 and 2010, natural gas and oil properties decreased by $75 million and increased by $176 million and $161 million, respectively, as a result of an increase or decrease in accrued acquisition, drilling and completion costs.

In 2012, 2011 and 2010, other property and equipment decreased by $25 million, increased by $64 million and decreased by $19 million, respectively, as a result of an increase or decrease in accrued costs.

As of December 31, 2012, 2011 and 2010, we recorded $242 million, $81 million and $371 million, respectively, of various liabilities related to the purchase of proved and unproved properties and other assets.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Years Ended December 31,		
	2012	2011	2010
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 3,062	$ 3,065	$ 466
Issuance of 0, 0 and 1,500,000 shares of 5.75% preferred stock	—	—	1,500
Issuance of 0, 0 and 1,100,000 shares of 5.75% preferred stock (Series A)	—	—	1,100
Conversion of 0, 3,000 and 5,000 shares of preferred stock for common stock	—	(3)	(1)
Balance, end of period	3,062	3,062	3,065
COMMON STOCK:			
Balance, beginning of period	7	7	6
Stock-based compensation	—	—	1
Balance, end of period	7	7	7
PAID-IN CAPITAL:			
Balance, beginning of period	12,146	12,194	12,146
Stock-based compensation	174	171	226
Exchange of convertible notes for 0, 0 and 298,500 shares of common stock	—	—	8
Conversion of preferred stock for 0, 111,111 and 20,774 shares of common stock	—	3	1
Purchase of contingent convertible notes	—	(123)	—
Offering/transaction expenses	—	(12)	(38)
Reduction in tax benefit from stock-based compensation	(30)	(26)	(13)
Dividends on common stock	—	(48)	(95)
Dividends on preferred stock	—	(15)	(44)
Exercise of stock options	3	2	3
Balance, end of period	12,293	12,146	12,194
RETAINED EARNINGS:			
Balance, beginning of period	1,608	190	(1,261)
Net income (loss) attributable to Chesapeake	(769)	1,742	1,774
Cumulative effect of accounting change, net of income taxes of $0, $0 and $89 million	—	—	(142)
Dividends on common stock	(231)	(168)	(95)
Dividends on preferred stock	(171)	(156)	(86)
Balance, end of period	437	1,608	190
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(166)	(168)	102
Hedging activity	(11)	3	(265)
Investment activity	(5)	(1)	(5)
Balance, end of period	(182)	(166)	(168)

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Years Ended December 31,		
	2012	2011	2010
	($ in millions)		
TREASURY STOCK – COMMON:			
Balance, beginning of period	(33)	(24)	(15)
Purchase of 652,443, 425,140 and 351,163 shares for company benefit plans	(16)	(11)	(9)
Release of 57,252, 93,906 and 7,069 shares from company benefit plans	1	2	—
Balance, end of period	(48)	(33)	(24)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	15,569	16,624	15,264
NONCONTROLLING INTERESTS:			
Balance, beginning of period	1,337	—	897
Sales of noncontrolling interests	1,077	1,340	—
Net income attributable to noncontrolling interests	175	15	—
Distributions to noncontrolling interest owners	(218)	(18)	—
Deconsolidation of investments, net	(44)	—	(897)
Balance, end of period	2,327	1,337	—
TOTAL EQUITY	$ 17,896	$ 17,961	$ 15,264

The accompanying notes are an integral part of these 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, oil and natural gas liquids (NGL) from underground reservoirs. We also provide substantial marketing, drilling and other oilfield services. Our operations are located onshore and in the continental United States.

Principles of Consolidation

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

Variable Interest Entities

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

Accounting Estimates

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

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

Risks and Uncertainties

Our business strategy is to continue growing our reserves and production and transitioning from an asset base primarily focused on natural gas to an asset base more balanced between natural gas and liquids production. This is a capital-intensive strategy, and we made capital expenditures in 2012 that exceeded our cash flow from operations, filling the gap with borrowings and proceeds from sales of assets that we determined were non-core or did not fit our long-term plans. See Note 11 for a description of our 2012 asset sales. We project that our capital expenditures will continue to exceed our operating cash flow in 2013, although by a significantly smaller amount. Our 2013 capital expenditure budget is approximately 50% less than our 2012 capital expenditures, and as operator of a substantial portion of our natural gas and oil properties under development, we have significant control and flexibility over the development plan and the associated timing, enabling us to expeditiously reduce at least a portion of our capital spending if needed. To add certainty to future estimated cash flows by mitigating our downside exposure to lower commodity prices, we currently have downside hedge protection on approximately 50% of our 2013 estimated natural gas production at a price of $3.62 per mcf and 85% of our 2013 estimated oil production at a price of $95.45 per bbl, allowing us to reduce the effect of price volatility on our cash flows and earnings before interest, taxes, depreciation, depletion and amortization (EBITDA). Based on these and other factors, we believe we have adequate borrowing capacity through our current credit arrangements, together with anticipated proceeds from transactions subject to binding agreements to sell non-core assets, to make up the difference between our budgeted capital expenditures and cash flow from operations in 2013.

As part of our asset sales planning and capital expenditure budgeting process, we closely monitor the resulting effects on the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our corporate revolving bank credit facility. While asset sales enhance our ability to reduce debt, sales of producing natural gas and oil properties may adversely affect the amount of cash flow and EBITDA we generate and reduce the amount and value of collateral available to secure our obligations, both of which can be exacerbated by low prices received for our production. In September 2012, we obtained an amendment to our revolving bank credit facility agreement that relaxed the required indebtedness to EBITDA ratio for the quarter ended September 30, 2012 and the four subsequent quarters. We would have been unable to meet the required ratio as of September 30, 2012 without this amendment primarily because the closing of certain asset sales transactions occurred in the fourth quarter and not in September as we had anticipated. As a result, without the amendment, we would have been unable to reduce our indebtedness sufficiently as of September 30, 2012 to maintain our covenant compliance. Failure to maintain compliance with the covenants of our revolving bank credit facility could result in the acceleration of outstanding indebtedness under the facility and lead to cross defaults under our senior note and contingent convertible senior note indentures, hedge facility, equipment master lease arrangements and term loan. See Note 3 for further discussion of our debt instruments, including the terms of the credit facility amendment. Based on reductions in our budgeted capital expenditures, expected commodity prices (including the prices for our currently hedged production), our forecasted drilling and production, projected levels of indebtedness and binding purchase and sale agreements for certain future asset sales, we expect we will be in compliance with the financial maintenance covenants of our corporate revolving bank credit facility through 2013. We believe the assumptions underlying our budget for this period are reasonable and that we have adequate flexibility, including the ability to adjust discretionary capital expenditures, to adapt to potential negative developments if needed to maintain covenant compliance.

Natural gas prices reached 10-year lows in 2012, and although our strategic focus on increasing liquids production is progressing and we have hedges in place covering approximately 50% of our projected 2013 natural gas production, we continue to have significant exposure to natural gas prices. Approximately 70% and 83% of our estimated proved reserves volumes as of December 31, 2012 and December 31, 2011, respectively, were natural gas, and natural gas represented approximately 80% and 84% of our natural gas, oil and NGL sales volumes for 2012 and 2011, respectively. In 2012, we reduced our estimate of proved reserves by 3.1 tcfe, or 17%, primarily due to the impact of downward natural gas price revisions. Natural gas prices used in estimating proved reserves at December 31, 2012 and 2011 decreased by 33% from $4.12 per mcf to $2.76 per mcf, causing the loss of significant proved undeveloped reserves for which future development is uneconomic. As a result of lower estimated reserves, in the 2012 third quarter, we were required to impair the carrying value of our natural gas and oil properties, and we could have additional impairments in the future. See *Natural Gas and Oil Properties* below for further discussion of our impairment of the carrying value of our natural gas and oil properties in 2012.

We believe we have taken appropriate measures to mitigate the risks and uncertainties facing us in 2013. Nevertheless, our ability to generate operating cash flow and close asset sales in order to manage debt is subject to all the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. We do not have binding agreements for all of our planned asset sales and our ability to consummate each of these transactions is subject to changes in market conditions and other factors beyond our control. If one or more of the transactions is not completed in the anticipated time frame, or at all, or for less proceeds than anticipated, our ability to fund budgeted capital expenditures and reduce our indebtedness could be adversely affected. Future impairments of the carrying value of our natural gas and oil properties, if any, will be dependent on many factors, including natural gas, oil and NGL prices, production rates, levels of reserves, the evaluation of costs excluded from amortization, the timing and impact of asset sales, future development costs and service costs.

Cash and Cash Equivalents and Restricted Cash

For purposes of the consolidated financial statements, Chesapeake considers investments in all highly liquid instruments with original maturities of three months or less at date of purchase to be cash equivalents. Restricted cash consists of balances required to be maintained by the terms of the respective agreements governing the activities of CHK Utica, L.L.C. (CHK Utica) and CHK Cleveland Tonkawa, L.L.C. (CHK C-T). For CHK Utica, we must retain a minimum cash balance equal to two quarterly dividend payments. In addition, cash proceeds received from CHK Utica asset sales must be used to fund CHK Utica's capital expenditures or to redeem its preferred shares. For CHK C-T, we must retain an amount of cash (remeasured quarterly) equal to (i) the next two quarters of preferred dividend payments plus (ii) the projected operating funding shortfall for the next six months. See Note 8 for further discussion of these transactions.

Accounts Receivable

Our accounts receivable are primarily from purchasers of natural gas and oil and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of all our counterparties and we generally require letters of credit or parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. We utilize an allowance method in accounting for bad debt based on historical trends in addition to specifically identifying receivables we believe will be uncollectible. During 2012, 2011 and 2010, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables. Accounts receivable as of December 31, 2012 and 2011 are detailed below.

	December 31, 2012	December 31, 2011
	($ in millions)	
Natural gas, oil and NGL sales	$ 1,457	$ 1,089
Joint interest	592	1,171
Oilfield services	24	43
Related parties[(a)]	23	45
Other	168	176
Allowance for doubtful accounts	(19)	(19)
Total accounts receivable	$ 2,245	$ 2,505

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

Natural Gas and Oil Properties

Chesapeake follows the full cost method of accounting under which all costs associated with natural gas and oil property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities (see Note 10). Capitalized costs are amortized on a composite unit-of-production method based on proved natural gas and oil reserves. Estimates of our proved reserves as of December 31, 2012 were prepared by both third-party engineering firms and Chesapeake's internal staff. Approximately 89% of these proved reserves estimates (by volume) as of December 31, 2012 were prepared by independent engineering firms. In addition, our internal engineers review and update our reserves on a quarterly basis. The average composite rates used for depreciation, depletion and amortization of natural gas and oil properties were $1.76 per mcfe in 2012, $1.37 per mcfe in 2011 and $1.35 per mcfe in 2010.

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

The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties and otherwise if impairment has occurred. Unevaluated properties are grouped by major prospect area where individual property costs are not significant. In addition, we analyze our unevaluated leasehold and transfer to evaluated properties leasehold that can be associated with reserves, leasehold that expired in the quarter or leasehold that is not a part of our development strategy and will be abandoned. As our strategic focus is shifting from a natural gas asset base to a more balanced natural gas and liquids asset base, and as our budgeted capital expenditures were being reduced in 2012, we identified undeveloped leasehold having a cost of $1.684 billion that would not be a part of our development strategy going forward. The acreage was primarily located in the Williston and DJ Basins, as well as other non-core leasehold located throughout our operating areas.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2012 and notes the year in which the associated costs were incurred.

	Year of Acquisition				
	2012	2011	2010	Prior	Total
			($ in millions)		
Leasehold acquisition cost	$ 1,826	$ 2,732	$ 3,519	$ 3,325	$ 11,402
Exploration cost	1,213	176	42	—	1,431
Capitalized interest	810	424	312	376	1,922
Total	$ 3,849	$ 3,332	$ 3,873	$ 3,701	$ 14,755

We also review, on a quarterly basis, the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC. 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 natural gas and oil cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In 2012, capitalized costs of natural gas and oil properties exceeded the estimated present value calculation of future net revenues from our proved reserves, net of related income tax considerations, resulting in an impairment in the carrying value of natural gas and oil properties in the 2012 third quarter of $3.315 billion. For the ceiling test calculation, costs used are those as of the end of the appropriate quarterly period. In calculating estimated future net revenues, current prices are calculated as the unweighted arithmetic average of natural gas and oil prices on the first day of each month within the 12-month period prior to the ending date of the quarterly period. 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 designated as cash flow hedges. Cash flow hedges locked in prior to September 30, 2012 relating to future production periods increased the 2012 third quarter ceiling test impairment by $279 million. As of December 31, 2012, none of our open derivative instruments were designated as cash flow hedges. Our natural gas and oil hedging activities are discussed in Note 9 of these consolidated financial statements. See *Risks and Uncertainties* above for a discussion of the reduction in our estimated proved reserves in 2012 and factors that could impact a future ceiling test impairment.

Two primary factors impacting the ceiling test are reserves levels and natural gas, oil and NGL prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an extended increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is written off as an expense.

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. 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 oilfield services equipment, including drilling rigs, rental tools, hydraulic fracturing and mining equipment, natural gas compressors, land, buildings and improvements, vehicles, office equipment, natural gas gathering systems and treating plants. The majority of our natural gas gathering systems and treating plants were sold in 2012 as discussed in Note 11 to these consolidated financial statements. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. The costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from the accounts, and the resulting gain or loss is reflected in operating costs. See Note 14 for further discussion of our gains and losses on the sales of other property and equipment. Other property and equipment costs, excluding land, are depreciated on a straight-line basis. A summary of our other property and equipment held for sale as of December 31, 2012 is summarized in *Held for Sale Assets and Liabilities* below. A summary of other property and equipment held for use and the useful lives is as follows:

	December 31, 2012	December 31, 2011	Useful Life
	($ in millions)		(in years)
Oilfield services equipment	$ 2,130	$ 1,632	3 - 15
Natural gas gathering systems and treating plants	—	1,455	3 - 20
Buildings and improvements	1,580	1,202	10 - 39
Natural gas compressors	505	303	20
Land	515	926	—
Other	1,178	1,124	2 - 20
Total other property and equipment, at cost	5,908	6,642	
Less: accumulated depreciation and amortization	(1,293)	(1,082)	
Total other property and equipment, net	$ 4,615	$ 5,560	

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 and discounted cash flow. We determined that certain of our property, plant and equipment were being carried at values that were not recoverable and in excess of fair value. As a result, we recognized impairments of $340 million, $46 million and $21 million in 2012, 2011 and 2010, respectively. See Note 14 for further discussion of these impairments.

Noncontrolling Interests

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

Capitalized Interest

During 2012, 2011 and 2010, interest of approximately $976 million, $727 million and $711 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. The increase in 2012 compared to 2011 was primarily the result of capitalizing additional interest on senior notes and term loans issued in 2012. Additional interest of $4 million, $6 million and $5 million was capitalized in 2012, 2011 and 2010, respectively, on midstream and oilfield services assets which were under construction. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings.

Goodwill

Goodwill represents the excess of the purchase price of a business combination over the fair value of the net assets acquired and is tested for impairment at least annually. Such test includes an assessment of qualitative and quantitative factors. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense.

Chesapeake's $43 million of goodwill as of December 31, 2012 consists of the excess consideration over the fair value of assets acquired of $28 million in the Bronco Drilling Company acquisition and $15 million in the Horizon Drilling Services acquisition. Quoted market prices are not available for these reporting units and their fair values are based upon several valuation analyses, including discounted cash flows.

We performed annual impairment tests of goodwill in the fourth quarters of 2012 and 2011. Based on these assessments, no impairment of goodwill was required. Our goodwill is included in our oilfield services segment.

Accounts Payable and Other Current Liabilities

Included in accounts payable as of December 31, 2012 and 2011 are liabilities of approximately $432 million and $604 million, respectively, representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Other current liabilities as of December 31, 2012 and 2011 are detailed below.

	December 31,	
	2012	2011
	($ in millions)	
Revenues and royalties due others	$ 1,337	$ 1,090
Accrued natural gas, oil and NGL drilling and production costs	525	590
Accrued acquisition costs	242	81
Joint interest prepayments received	749	865
Accrued payroll and benefits	224	199
Accrued dividends	101	99
Other	563	473
Total other current liabilities	$ 3,741	$ 3,397

Other Long-Term Liabilities

Other long-term liabilities as of December 31, 2012 and 2011 are detailed below.

	December 31,	
	2012	2011
	($ in millions)	
CHK Utica ORRI conveyance obligation[a]	$ 275	$ 290
CHK C-T ORRI conveyance obligation[b]	164	—
Financing lease obligations[c]	143	143
Mortgages payable[d]	56	56
Other	538	329
Total other long-term liabilities	$ 1,176	$ 818

(a) $18 million and $10 million of the total $293 million and $300 million obligations are recorded in other current liabilities as of December 31, 2012 and December 31, 2011, respectively. See Note 8 for further discussion of the transaction.

(b) $14 million of the total $178 million obligation is recorded in other current liabilities as of December 31, 2012. See Note 8 for further discussion of the transaction.

(c) In 2009, we financed 113 real estate surface assets in the Barnett Shale area for approximately $145 million and entered into a 40-year master lease agreement under which we agreed to lease the sites for approximately $15 million to $27 million annually. This lease transaction was recorded as a financing lease and the cash received was recorded with an offsetting long-term liability on the consolidated balance sheet. Chesapeake exercised its option to repurchase two of the assets in 2010 and one of the assets in 2011. We anticipate making lease payments related to these assets of approximately $15 million in 2013, $16 million in 2014, $17 million in 2015, $17 million in 2016, $17 million in 2017 and $709 million in 2018 and beyond.

(d) In 2009, we financed our regional Barnett Shale headquarters building in Fort Worth, Texas for net proceeds of approximately $54 million with a five-year promissory note which has a floating rate of prime plus 275 basis points. At our option, after June 2012 we could prepay the promissory note in full without penalty. As of December 31, 2012, our Barnett Shale headquarters building was classified as property and equipment held for sale on our consolidated balance sheet. Subsequent to December 31, 2012, we prepaid in full the promissory note.

Debt Issuance and Hedging Facility Costs

Included in other long-term assets are costs associated with the issuance of our senior notes and costs primarily associated with our term loans, revolving bank credit facilities and hedging facility. The remaining unamortized issuance costs at December 31, 2012 and 2011 totaled $182 million and $163 million, respectively, and are being amortized over the life of the senior notes, term loan, revolving bank credit facilities or hedging facility using the effective interest method.

Asset Retirement Obligations

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

Revenue Recognition

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

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 liability net position as of December 31, 2012 and 2011 was $9 million and $8 million, respectively.

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

Oilfield Services Revenue. Our oilfield services operating segment is responsible for contract drilling, hydraulic fracturing, oilfield rentals, oilfield trucking and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties.

- *Drilling.* We earn revenues by drilling oil and natural gas wells for our customers under daywork contracts. We recognize revenue on daywork contracts for the days completed based on the dayrate specified in each contract. Payments received and costs incurred for mobilization services are recognized over the days of actual mobilization.
- *Hydraulic Fracturing.* We recognize revenue upon the completion of each fracturing stage. We typically complete one or more fracturing stages per day per active crew during the course of a job. A stage is considered complete when the customer requests or the job design dictates that pumping discontinue for that stage. Invoices typically include a lump sum equipment charge determined by the rate per stage specified in each contract and product charges for sand, chemicals and other products actually consumed during the course of providing our services.
- *Oilfield Rentals*. We rent many types of oilfield equipment including drill pipe, drill collars, tubing, blowout preventers, and frac and mud tanks, and also provide air drilling services and services associated with the transfer of fresh water to the wellsite. We price our rentals and services by the day or hour based on the type of equipment being rented and the service job performed and recognize revenue ratably over the term of the rental.
- *Oilfield Trucking*. Oilfield trucking provides rig relocation and logistics services as well as fluid handling services. Our trucks move drilling rigs, crude oil, other fluids and construction materials to and from the wellsites and also transport produced water from the wellsites. We price these services by the hour and recognize revenue as services are performed.
- *Other Operations.* We design, engineer and fabricate natural gas compressor packages that we primarily sell to Chesapeake. We price our compression units based on certain specifications such as horsepower, stages and additional options. We recognize revenue upon completion and transfer of ownership of the natural gas compression unit.

All significant intercompany accounts and transactions have been eliminated.

Derivatives

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

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

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

Stock-Based Compensation

Chesapeake's stock-based compensation program during 2012, 2011 and 2010 consisted of restricted stock issued to employees and non-employee directors. Prior to 2006, we also issued stock options. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the fair value of the equity instruments at the date of the grant. 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. We utilized the Black-Scholes option pricing model to measure the fair value of stock options. To the extent compensation cost relates to employees directly involved in natural gas and oil acquisition, divestiture, exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expenses, natural gas, oil and NGL production expenses, marketing, gathering and compression expenses or oilfield services expenses.

For the years ended December 31, 2012, 2011 and 2010, we recorded the following stock-based compensation:

	Years Ended December 31,		
	2012	2011	2010
		($ in millions)	
Natural gas and oil properties	$ 71	$ 112	$ 120
General and administrative expenses	71	92	84
Natural gas, oil and NGL production expenses	24	33	35
Marketing, gathering and compression expenses	15	17	18
Oilfield services expense	10	11	9
Total	$ 191	$ 265	$ 266

Cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock are classified as financing cash inflows, while reductions in benefits are classified as operating cash outflows in our consolidated statements of cash flows. For the years ended December 31, 2012, 2011 and 2010, we recognized reductions in tax benefits related to stock-based compensation of $30 million, $26 million and $13 million, respectively.

Held for Sale Assets and Liabilities

We are currently pursuing the sale of our remaining midstream business, and we expect to complete these sales in the next 12 months. The midstream business qualified as held for sale as of December 31, 2012 and is reported under our marketing, gathering and compression operating segment. In addition, we are pursuing the sale within the next 12 months of various other property and equipment, including certain drilling rigs and land and buildings primarily in the Fort Worth, Texas area. The drilling rigs are reported under our oilfield services operating segment, and the land and buildings are reported under our other operating segment. Natural gas and oil properties that we intend to sell are not presented as held for sale pursuant to the rules governing full cost accounting for oil and gas properties. A summary of the assets and liabilities held for sale on our consolidated balance sheet as of December 31, 2012 is detailed below.

	December 31, 2012
	($ in millions)
Accounts receivable	$ 4
Current assets held for sale	$ 4
Natural gas gathering systems and treating plants, net of accumulated depreciation	$ 352
Oilfield services equipment, net of accumulated depreciation[(a)]	27
Other property and equipment, net of accumulated depreciation and amortization	255
Property and equipment held for sale, net	$ 634
Accounts payable	$ 4
Accrued liabilities	17
Current liabilities held for sale	$ 21

(a) Subsequent to December 31, 2012, we sold eight rigs classified as held for sale assets as of December 31, 2012 for proceeds of approximately $27 million.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2011 and 2010 to conform to the presentation used for the 2012 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 year ended December 31, 2012, the following shares of unvested restricted stock and cumulative convertible preferred stock and associated adjustments to net income, consisting of dividends on such shares, were not included in the calculation of diluted EPS, as the effect was antidilutive:

	Net Income Adjustments ($ in millions)	Shares (in millions)
Year Ended December 31, 2012:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$ 86	56
5.75% cumulative convertible preferred stock (series A)	$ 63	39
5.00% cumulative convertible preferred stock (series 2005B)	$ 10	5
4.50% cumulative convertible preferred stock	$ 12	6
Unvested restricted stock	$ —	5

As a result of the net loss to common stockholders for the year ended December 31, 2012, basic weighted average shares outstanding, which is used in computing basic EPS, and diluted weighted average shares outstanding, which is used in computing diluted EPS, were 643 million shares. The basic and diluted loss per common share was $1.46.

For the years ended December 31, 2011 and 2010, all outstanding securities that were convertible into common stock were included in the calculation of diluted EPS. A reconciliation of basic EPS and diluted EPS for 2011 and 2010 is as follows:

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

3. Debt

Our long-term debt consisted of the following as of December 31, 2012 and 2011:

	December 31, 2012	December 31, 2011
	($ in millions)	
Term loan due 2017	$ 2,000	$ —
7.625% senior notes due 2013[(a)]	464	464
9.5% senior notes due 2015	1,265	1,265
6.25% euro-denominated senior notes due 2017[(b)]	454	446
6.5% senior notes due 2017	660	660
6.875% senior notes due 2018	474	474
7.25% senior notes due 2018	669	669
6.625% senior notes due 2019[(c)]	650	650
6.775% senior notes due 2019	1,300	—
6.625% senior notes due 2020	1,300	1,300
6.875% senior notes due 2020	500	500
6.125% senior notes due 2021	1,000	1,000
2.75% contingent convertible senior notes due 2035[(d)]	396	396
2.5% contingent convertible senior notes due 2037[(d)]	1,168	1,168
2.25% contingent convertible senior notes due 2038[(d)]	347	347
Corporate revolving bank credit facility	—	1,719
Midstream revolving bank credit facility	—	1
Oilfield services revolving bank credit facility	418	29
Discount on senior notes and term loans[(e)]	(465)	(490)
Interest rate derivatives[(f)]	20	28
Total debt, net	12,620	10,626
Less current maturities of long-term debt, net[(a)]	(463)	—
Total long-term debt, net	$ 12,157	$ 10,626

(a) These senior notes are due in July 2013. There is $1 million of discount associated with these notes.

(b) The principal amount shown is based on the exchange rate of $1.3193 to €1.00 and $1.2973 to €1.00 as of December 31, 2012 and 2011, respectively. See Note 9 for information on our related foreign currency derivatives.

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

(d) 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 quarterly. In the fourth quarter of 2012, 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 2013 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. During 2012, the notes were not convertible under this provision. 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 in which 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	$ 48.31	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 63.93	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.01	June 14, 2019

(e) Discount as of December 31, 2012 and December 31, 2011 included $376 million and $444 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is based on an effective yield method. Also includes $40 million associated with our November 2012 term loan.

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

Total principal amount of debt maturities, using earliest conversion date, for the five years ended December 31, 2012 are as follows:

	Principal Amount of Debt Maturities
	($ in millions)
2013	$ 464
2014	—
2015	1,661
2016	418
2017	4,282
2018 and thereafter	6,240
Total	$ 13,065

Term Loans

November 2012 Term Loan. In November 2012, we established an unsecured five-year term loan credit facility in an aggregate principal amount of $2.0 billion for net proceeds of $1.935 billion (November 2012 term loan). Our obligations under the new facility rank equally with our outstanding senior notes and contingent convertible senior notes and are unconditionally guaranteed on a joint and several basis by our direct and indirect wholly owned subsidiaries that are subsidiary guarantors under the indentures for such notes. Amounts borrowed under the new facility, which priced at 98% of par, bear interest at our option, at either (a) the Eurodollar rate, which is based on the London Interbank Offered Rate (LIBOR), plus a margin of 4.50% or (b) a base rate equal to the greater of (i) the Bank of America, N.A. prime rate, (ii) the federal funds effective rate plus 0.50% per annum and (iii) the Eurodollar rate that would be applicable to a Eurodollar loan with an interest period of one month plus 1% per annum, in each case, plus a margin of 3.50%. The Eurodollar rate is subject to a floor of 1.25% per annum, and the base rate is subject to a floor of 2.25% per annum. Interest is payable quarterly or, if the Eurodollar rate applies, it may be payable at more frequent intervals. We used the net proceeds of the new term loan to fully repay the remaining outstanding borrowings under our existing term loans and to repay outstanding borrowings under the Company's corporate revolving bank credit facility.

The November 2012 term loan matures on December 2, 2017 and is non-callable in the first year but may be voluntarily repaid without penalty in the second and third years at par plus a specified call premium and may be voluntarily repaid at any time thereafter at par. The term loan may also be refinanced or amended to extend the maturity date at our option, subject to lender approval.

The term loan credit agreement contains negative covenants substantially similar to those contained in the Company's corporate revolving bank credit facility, including covenants that limit our ability to incur indebtedness, grant liens, make investments, loans and restricted payments and enter into certain business combination transactions. Other covenants include additional restrictions regarding the incurrence of certain unsecured indebtedness, the incurrence of secured indebtedness, the disposition of assets and the prepayment of certain indebtedness. The term loan credit agreement does not contain financial maintenance covenants.

We were in compliance with all covenants under the term loan credit agreement at December 31, 2012. If we should fail to perform our obligations under the agreement, the term loan could be terminated and any outstanding borrowings under the term loan credit agreement could be declared immediately due and payable. The term loan credit agreement also has cross default provisions that apply to other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million.

May 2012 Term Loans. In May 2012, we entered into $4.0 billion of unsecured term loans under a credit agreement that provided for term loans in an aggregate principal amount of $4.0 billion (May 2012 term loans). The net proceeds of the term loans of approximately $3.789 billion after discount, customary fees and syndication costs were used to repay borrowings under our corporate revolving credit facility and for general corporate purposes. The term loans were issued at a discount of 3%, or $120 million, and the customary fees and syndication costs incurred were approximately $91 million. In October and November 2012, we used $4.0 billion in proceeds from asset sales and our November 2012 term loan discussed above to fully repay the May 2012 term loans. We recorded $200 million of associated losses with the repayment, including $86 million of deferred charges and $114 million of debt discount.

Chesapeake Senior Notes and Contingent Convertible Senior Notes

The Chesapeake senior notes and the contingent convertible senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Chesapeake's obligations under the senior notes and the contingent convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our wholly owned subsidiaries. Certain of our oilfield services subsidiaries, subsidiaries with noncontrolling interests, subsidiaries qualified as variable interest entities, and certain de minimis subsidiaries are not guarantors. See Note 18 for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries.

We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole or redemption prices. Our senior notes are governed by indentures containing covenants that may limit our ability and our subsidiaries' ability to incur certain secured indebtedness, enter into sale/leaseback transactions, and consolidate, merge or transfer assets. The indentures governing the contingent convertible senior notes do not have any financial or restricted payment covenants. The senior notes and contingent convertible senior notes indentures have cross default provisions that apply to other indebtedness the Company or any guarantor subsidiary may have from time to time with an outstanding principal amount of $50 million or $75 million, depending on the indenture.

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

During 2012, we issued $1.3 billion of 6.775% Senior Notes due 2019 in a registered public offering. We used the net proceeds of $1.263 billion from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility. At any time from and including November 15, 2012 to and including March 15, 2013, we may redeem some or all of the notes at a redemption price equal to 100% of the principal amount of the notes plus accrued and unpaid interest, if any, to the redemption date; provided that upon any redemption of the notes in part (and not in whole) pursuant to this redemption provision, at least $250 million aggregate principal amount of the notes remains outstanding.

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

During 2011, we completed and settled tender offers to purchase the following principal amounts of senior notes and contingent convertible senior notes. We funded the purchase of the notes with a portion of the net proceeds we received from the sale of our Fayetteville Shale assets. See Note 11 for further discussion of our Fayetteville Shale asset sale.

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

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

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

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

In July 2013, the $464 million aggregate principal amount of our 7.625% senior notes will be due. No other scheduled principal payments are required on our senior notes until 2015.

COO Senior Notes

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

The COO senior notes are the unsecured senior obligations of COO and rank equally in right of payment with all of COO's other existing and future senior unsecured indebtedness and rank senior in right of payment to all of its future subordinated indebtedness. The COO senior notes are jointly and severally, fully and unconditionally guaranteed by all of COO's wholly owned subsidiaries, other than de minimis subsidiaries. The notes may be redeemed at any time at specified make-whole or redemption prices and, prior to November 15, 2014, up to 35% of the aggregate principal amount may be redeemed in connection with certain equity offerings. Holders of the COO notes have the right to require COO to repurchase their notes upon a change of control on the terms set forth in the indenture, and COO must offer to repurchase the notes upon certain asset sales. The COO senior notes are subject to covenants that may, among other things, limit the ability of COO and its subsidiaries to make restricted payments, incur indebtedness, issue preferred stock, create liens, and consolidate, merge or transfer assets. The COO senior notes have cross default provisions that apply to other indebtedness COO or any of its guarantor subsidiaries may have from time to time with an outstanding principal amount of $50 million or more.

Under a registration rights agreement, we agreed to file a registration statement within 365 days after the closing of the COO senior notes offering enabling holders of the COO senior notes to exchange the privately placed COO senior notes for publicly registered notes with substantially the same terms. We are required to use our commercially reasonable best efforts to cause the registration statement to become effective as soon as practicable after filing and to consummate the exchange offer on the earliest practicable date after such date, but in no event later than 60 days after the date the registration statement has become effective. We also agreed to make additional interest payments to holders, up to a maximum of 1% per annum, of the COO senior notes if we do not comply with our obligations under the registration rights agreement. We did not file a registration statement within 365 days after the closing of the COO senior notes and in 2012 accrued approximately $1 million of additional expense we expect to incur related to this delay.

Bank Credit Facilities

During 2012, we used three revolving bank credit facilities as sources of liquidity. In June 2012, we paid off and terminated our midstream credit facility. Our two remaining revolving bank credit facilities are described below.

	Corporate Credit Facility[(a)]	Oilfield Services Credit Facility[(b)]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$ 4,000	$ 500
Amount outstanding as of December 31, 2012	$ —	$ 418
Letters of credit outstanding as of December 31, 2012	$ 31	$ —

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.

(b) Borrower is COO.

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, our credit facilities do not contain provisions which would trigger an acceleration of amounts due under the respective facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Corporate Credit Facility. Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by proved reserves and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A. or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.50% to 1.25% per annum according to our senior unsecured long-term debt ratings, or (ii) the Eurodollar rate, which is based on LIBOR, plus a margin that varies from 1.50% to 2.25% per annum according to our senior unsecured long-term debt ratings. These margins may be increased pursuant to the terms of the recent credit facility amendment discussed below. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. In September 2012, we entered into an amendment to the credit facility agreement, effective September 30, 2012. See *Risks and Uncertainties* in Note 1 for further discussion. The amendment, among other things, adjusts our required indebtedness to EBITDA ratio as set forth below through the earlier of (a) December 31, 2013 and (b) the date on which we elect to reinstate the indebtedness to EBITDA ratio in effect prior to the amendment (in either case, the "Amendment Effective Period"). The amendment increased the maximum indebtedness to EBITDA ratio as of September 30, 2012 from 4.00 to 1.00 to 6.00 to 1.00 and revises the required ratio for the next four quarters as shown below. The ratio returns to 4.00 to 1.00 as of December 31, 2013 and thereafter.

Effective Date	Indebtedness to EBITDA Ratio
December 31, 2012	5.00 to 1.00
March 31, 2013	4.75 to 1.00
June 30, 2013	4.50 to 1.00
September 30, 2013	4.25 to 1.00

The credit facility amendment increases the applicable margin by 0.25% for borrowings under the corporate credit facility on each day during the Amendment Effective Period when borrowings exceed 50% of the borrowing capacity and requires us to pay a fee to each lender in an amount equal to 0.05% of its revolving commitment in the event that the Amendment Effective Period is in effect on June 30, 2013. Based on current commitment levels, this would result in an additional payment of $2 million. The amendment does not allow our collateral value securing the borrowings to be more than $75 million below the collateral value that was in effect as of September 30, 2012 during the Amendment Effective Period. We were in compliance with all covenants under the amended agreement as of September 30, 2012 and December 31, 2012.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and certain of our wholly owned subsidiaries. If we should fail to perform our obligations under the agreement, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $50 million or more, would constitute an event of default under our senior note and contingent convertible 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 our hedge facility, equipment master lease agreements, term loan and other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million. In addition, the facility contains a restriction on our ability to declare and pay cash dividends on our common or preferred stock if an event of default has occurred.

Oilfield Services Credit Facility. Our $500 million syndicated oilfield services revolving bank credit facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. Borrowings under the oilfield services credit facility are secured by all of the assets of the wholly owned subsidiaries of COO, itself an indirect wholly owned subsidiary of Chesapeake. The facility has initial commitments of $500 million and may be expanded to $900 million at COO’s option, subject to additional bank participation. Borrowings under the credit facility are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries for this facility, but they are unrestricted subsidiaries under Chesapeake's senior notes, contingent convertible senior notes, term loan and corporate revolving bank credit facility), and bear interest at our option at either (i) the greater of the reference rate of Bank of America, N.A., the federal funds effective rate plus 0.50%, or one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 1.00% to 1.75% per annum, or (ii) the Eurodollar rate, which is based on LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the credit facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The oilfield services credit facility agreement contains various covenants and restrictive provisions which limit the ability of COO and its restricted subsidiaries to incur additional indebtedness, make investments or loans and create liens. The agreement requires maintenance of a leverage ratio based on the ratio of lease adjusted indebtedness to earnings before interest, taxes, depreciation, amortization and rent (EBITDAR), a senior secured leverage ratio based on the ratio of secured indebtedness to EBITDA and a fixed charge coverage ratio based on the ratio of EBITDAR to lease adjusted interest expense, in each case as defined in the agreement. COO was in compliance with all covenants under the agreement at December 31, 2012. If COO or its restricted subsidiaries should fail to perform their obligations under the agreement, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $50 million or more, would constitute an event of default under our COO senior note indenture, which could in turn result in the acceleration of the COO senior note indebtedness. The oilfield services credit facility agreement also has cross default provisions that apply to other indebtedness COO and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

Midstream Credit Facility. Prior to June 15, 2012, we utilized a $600 million midstream syndicated senior secured revolving bank credit facility to fund capital expenditures to build natural gas gathering and other systems in support of our drilling program and for general corporate purposes associated with our midstream operations. With the anticipated sale of our midstream business in the second half of 2012, on June 15, 2012, we paid off and terminated our midstream credit facility.

4. Contingencies and Commitments

Contingencies

Litigation and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek an indeterminate amount of damages. We estimate and provide for potential losses that may arise out of litigation and regulatory proceedings to the extent that such losses are probable and can be reasonably estimated. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different. Our total estimated liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. We account for legal defense costs in the period the costs are incurred.

July 2008 Common Stock Offering. On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the Company and certain of its officers and directors along with certain underwriters of the Company's July 2008 common stock offering. Following the appointment of a lead plaintiff and counsel, the plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. On September 2, 2010, the court denied the defendants' motion to dismiss, and the court certified the class on March 30, 2012. Defendants moved for summary judgment on grounds of loss causation and materiality on December 16, 2011, and the motion was fully briefed as of August 21, 2012. Discovery in the case is proceeding. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case.

A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against certain current and former directors and officers of the Company asserting breaches of fiduciary duties relating to alleged material omissions in the registration statement for the July 2008 offering. On October 22, 2012, the court issued an order staying the derivative action until resolution of the federal class action. A second derivative action relating to the July 2008 offering was filed against certain current and former directors and officers of the Company in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. This action also asserts breaches of fiduciary duties with respect to alleged material omissions in the offering registration statement. On November 30, 2011, the Company filed a motion to dismiss the action, which was denied on September 28, 2012. Pursuant to court order, nominal defendant Chesapeake filed an answer on October 12, 2012. By stipulation between the parties, the individual defendants are not required to answer the complaint unless and until the plaintiff establishes standing to pursue claims derivatively.

2008 CEO Compensation and Related Party Transaction. Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7 and May 20, 2009 against the Company's directors alleging, among other things, breaches of fiduciary duties relating to the 2008 compensation of the Company's CEO, Aubrey K. McClendon, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition naming Chesapeake as a nominal defendant was filed on June 23, 2009. Chesapeake's motion to dismiss was granted on February 26, 2010, and the Oklahoma Court of Civil Appeals affirmed the dismissal on August 26, 2011. The plaintiffs filed a petition for writ of certiorari with the Oklahoma Supreme Court on September 13, 2011. The appeal is currently stayed pending resolution of the settlement referenced in the following paragraph.

On January 30, 2012, the District Court of Oklahoma County, Oklahoma approved a settlement between the parties in the consolidated derivative action, as well as a case on appeal at the Oklahoma Court of Civil Appeals requesting inspection of Company books and records relating to the December 2008 employment agreement with Mr. McClendon. The principal terms of the settlement include the rescission of the sale of an antique map collection that occurred in December 2008 between Mr. McClendon and the Company, whereby Mr. McClendon will pay the Company approximately $12 million plus interest and the Company will reconvey the map collection to Mr. McClendon, and the adoption and/or implementation of a variety of corporate governance measures. The court awarded attorney fees and expenses to plaintiffs' counsel in the amount of $3.75 million. Pursuant to the settlement, the consolidated derivative action and books and records action were dismissed with prejudice against all defendants. On February 29, 2012, certain shareholders filed a petition in error with the Oklahoma Supreme Court opposing the terms of the settlement. Their appeal was fully briefed as of October 24, 2012.

On September 6 and 8, 2011, in separate derivative actions filed in the U.S. District Court for the Western District of Oklahoma against certain of the Company's current and former directors, two shareholders alleged that the Chesapeake Board wrongfully refused their demands to investigate purported breaches of fiduciary duties relating to Mr. McClendon's 2008 compensation and, as a result, each of these shareholders asserts he is entitled to seek relief on behalf of the Company. These federal derivative actions were consolidated on December 23, 2011 and on March 14, 2012 were stayed until 30 days after the Supreme Court of Oklahoma resolves the appeal of the settlement of the consolidated derivative action and books and records action.

FWPP, Conflict of Interest and Other Matters. From April 19 to June 29, 2012, 13 substantially similar shareholder derivative actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company and its directors alleging, among other things, violations of Section 14 of the Securities Exchange Act of 1934 and Rule 14a-9 promulgated thereunder for purported material misstatements in the Company's 2009 and subsequent proxy statements related to Mr. McClendon's participation in the Founder Well Participation Program (FWPP) and breaches of fiduciary duties, corporate waste, and unjust enrichment against the Board for failing to make proper disclosures in the proxy statements and failing to properly monitor Mr. McClendon's personal use of assets acquired pursuant to the FWPP. As described in Note 6, in conjunction with Mr. McClendon's employment agreement with the Company, the FWPP provides Mr. McClendon a contractual right through June 2014 to participate and invest as a working interest owner (with up to a 2.5% working interest) in new wells drilled on the Company's leasehold. On July 13, 2012, these 13 shareholder actions were consolidated into a single case. On April 27, 2012, a shareholder derivative action was filed in the District Court of Oklahoma County, Oklahoma setting forth substantially similar claims to those alleged in the federal shareholder actions. Plaintiffs in both the federal consolidated derivative action and the state court derivative action stipulated to stay their cases pending a ruling on the motion to dismiss filed in the federal securities class action described in the following paragraph. On February 6, 2013, another shareholder derivative suit was filed in the District Court of Oklahoma County, Oklahoma asserting claims substantially similar to those of the stayed derivative cases and seeking a temporary restraining order barring the Company from providing Mr. McClendon severance compensation and benefits. The hearing for the restraining order is set for March 29, 2013.

A putative class action was filed in the U.S. District Court for the Western District of Oklahoma on April 26, 2012 against the Company and Mr. McClendon alleging violations of Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934. On July 20, 2012, the court appointed a lead plaintiff, which filed an amended complaint on October 19, 2012 against the Company, Mr. McClendon and certain other officers. The amended complaint asserts claims under Sections 10(b) (and Rule 10b-5) and 20(a) of the Securities Exchange Act of 1934 based on alleged misrepresentations regarding the Company's asset monetization strategy, including liabilities associated with its volumetric production payment (VPP) transactions, as well as Mr. McClendon's personal loans and the Company's internal controls. The action seeks class certification, damages of an unspecified amount and attorneys' fees and other costs. The Company and other defendants filed a motion to dismiss the action on December 6, 2012, and the plaintiff filed its response on January 23, 2013. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case.

On June 19, July 17 and July 20, 2012, putative class actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company, Chesapeake Energy Savings and Incentive Stock Bonus Plan (the Plan), and certain of the Company's officers and directors alleging breaches of fiduciary duties under the Employee Retirement Income Security Act (ERISA). The actions are brought on behalf of participants and beneficiaries of the Plan, and allege that as fiduciaries of the Plan, defendants owed fiduciary duties, which they purportedly breached by, among other things, failing to manage and administer the Plan's assets with appropriate skill and care, failing to disclose material information concerning such matters as Mr. McClendon's participation in the FWPP and his related financing arrangements and the Company's VPP transactions, engaging in activities that were in conflict with the best interest of the Plan, and permitting the Plan to over-concentrate in Chesapeake stock. The plaintiffs seek class certification, damages of an unspecified amount, equitable relief, and attorneys' fees and other costs. The three cases have been consolidated and a consolidated amended complaint was filed on February 21, 2013. Defendants have 60 days from that date in which to respond. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.

On May 2, 2012, Chesapeake and Mr. McClendon received notice from the U.S. Securities and Exchange Commission that its Fort Worth Regional Office had commenced an informal inquiry into, among other things, certain of the matters alleged in the foregoing lawsuits. On December 21, 2012, the SEC's Fort Worth Regional Office advised Chesapeake that its inquiry is continuing as an investigation and it has issued subpoenas for information and testimony. The Company, including Mr. McClendon, is providing information to the SEC in connection with this matter. The Company is also responding to related inquiries from other governmental and regulatory agencies and self-regulatory organizations.

Director and Officer Use of Company Aircraft. On May 8, 2012, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against the Company's directors alleging, among other things, breaches of fiduciary duties and corporate waste related to the Company's officers and directors' use of the Company's fractionally owned corporate jets. Chesapeake was named a nominal defendant in the derivative action. On August 21, 2012, the District Court granted the Company's motion to dismiss the case. On December 6, 2012, the plaintiff filed an amended petition in error with the Oklahoma Supreme Court, and on December 26, 2012 nominal defendant/appellee Chesapeake filed its response. The appeal is currently before the Oklahoma Court of Appeals by appointment of the Supreme Court.

Antitrust Investigations. On June 29, 2012, Chesapeake received a subpoena duces tecum from the Antitrust Division, Midwest Field Office of the U.S. Department of Justice. The subpoena requires the Company to produce certain documents before a grand jury in the Western District of Michigan, which is conducting an investigation into possible violations of antitrust laws in connection with the purchase and lease of oil and gas rights. The Company has also received demands for documents and information from certain state governmental agencies in connection with other investigations relating to the Company's purchase and lease of oil and gas rights. Chesapeake has been providing information in response to these investigations. Chesapeake's Board of Directors commenced its own investigation of these allegations in June 2012 and recently concluded that the Company did not violate antitrust laws in connection with the acquisition of Michigan oil and gas rights in 2010.

Business Operations. Chesapeake is 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 contract actions, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their natural gas and oil interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal. Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to the Company's business operations is likely to have a material adverse effect on its consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Environmental Risk

The nature of the natural gas and oil business carries with it certain environmental risks for Chesapeake and its subsidiaries. Chesapeake has implemented various policies, procedures, training and auditing to reduce and mitigate such environmental risks. Chesapeake conducts periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are set for potential environmental liabilities that are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions and divestitures by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and addressing the potential liability. Depending on the extent of an identified environmental concern, Chesapeake may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition, or agree to assume liability for the remediation of the property.

There are presently pending against our subsidiary, Chesapeake Appalachia, L.L.C. (CALLC), orders for compliance first initiated in the 2010 fourth quarter by the U.S. Environmental Protection Agency (EPA) related to our compliance with Clean Water Act (CWA) permitting requirements in West Virginia. We have responded to all pending orders and are actively working with the EPA to resolve these matters.

The CWA provides authority for significant civil penalties for the placement of fill in a jurisdictional stream or wetland without a permit from the Army Corps of Engineers. CWA civil penalties can be as high as $37,500 per day, per violation. The CWA sets forth subjective criteria, including degree of fault and history of prior violations, that influence CWA penalty assessments, and the EPA may also seek to recover the economic benefit derived from non-compliance. While we expect that resolution of the EPA's orders for compliance will include monetary sanctions exceeding $100,000, we believe the liability with respect to these matters will not have a material effect on the consolidated financial position, results of operations or cash flow of the Company.

Commitments

Rig Leases

In a series of transactions beginning in 2006, our drilling subsidiaries have sold 68 drilling rigs (net of 26 repurchased rigs) and related equipment and entered into master lease agreements under which we agreed to lease the rigs from the buyer for initial terms of five to ten years. The lease commitments are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related net gains are amortized to oilfield services expenses over the lease term. Under the leases, we can exercise an early purchase option or we can purchase the rigs at the expiration of the lease for the fair market value at the time. In addition, in most cases we have the option to renew a lease for negotiated new terms at the expiration of the lease. During 2012, we repurchased 25 rigs from various lessors for an aggregate purchase price of $61 million. Of the $61 million, approximately $25 million was deemed to be early lease termination costs and was recognized as *Impairments of Fixed Assets and Other* in the consolidated statement of operations. See Note 14 for further discussion.

Compressor Leases

Through various transactions beginning in 2007, our compression subsidiary has sold 2,322 compressors (net of 231 repurchased compressors), a significant portion of its compressor fleet, and entered into a master lease agreement. The term of the agreement varies by buyer ranging from four to ten years. The lease commitments are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related net gains are amortized to marketing, gathering and compression expenses over the lease term. Under the leases, we can exercise an early purchase option or we can purchase the compressors at the expiration of the lease for the fair market value at the time. In addition, in most cases we have the option to renew a lease for negotiated new terms at the expiration of the lease. During October and November 2012, we repurchased 220 compressor units for approximately $28 million from various lessors.

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

	December 31, 2012			
	Rigs	Compressors	Other	Total
	($ in millions)			
2013	$ 93	$ 71	$ 17	$ 181
2014	82	125	13	220
2015	37	51	11	99
2016	68	105	9	182
2017	21	23	3	47
After 2017	6	30	3	39
Total	$ 307	$ 405	$ 56	$ 768

Rent expense, including short-term rentals, for the years ended December 31, 2012, 2011 and 2010 was $185 million, $184 million and $161 million, respectively.

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of natural gas and liquids to move certain of our production to market. Working interest owners and royalty interest owners will be responsible for their proportionate share of these costs. Commitments related to gathering, processing and transportation agreements are not recorded in the accompanying consolidated balance sheets; however, they are reflected as adjustments to future natural gas, oil and NGL sales prices used in our proved reserves estimates.

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

	December 31, 2012
	($ in millions)
2013	$ 1,540
2014	1,988
2015	1,801
2016	1,895
2017	1,922
2018 - 2099	9,344
Total	$ 18,490

Drilling Contracts

Chesapeake has contracts with various drilling contractors to utilize approximately 26 rigs with terms ranging from one month to three years. These commitments are not recorded in the accompanying consolidated balance sheets. As of December 31, 2012, the aggregate undiscounted minimum future payments under these drilling rig commitments are presented below:

	December 31, 2012
	($ in millions)
2013	$ 123
2014	68
2015	11
Total	$ 202

Drilling Commitments

In December 2011, as part of our Utica joint venture development agreement with Total S.A. (Total) (see Note 11), we committed to spud no less than 90 cumulative Utica wells by December 31, 2012, 270 cumulative wells by December 31, 2013 and 540 cumulative wells by December 31, 2014. Through December 31, 2012, we had spud 143 cumulative Utica wells and met our 2012 commitment. If we fail to meet the drilling commitment at any such year end for any reason other than a force majeure event, the drilling carry percentage used to determine our promoted well reimbursement will be reduced from 60% to 45% for a number of wells drilled in the following calendar year equal to the number of wells we were short the drilling commitment. As such, any reduction would only affect the timing of the receipt of the drilling carry but not the total drilling carry to be received.

We have also committed to drill wells in conjunction with our CHK Utica and CHK C-T financial transactions and in conjunction with the formation of the Chesapeake Granite Wash Trust. See Note 8 for discussion of these transactions and commitments.

In conjunction with the acceleration in October 2011 of the remaining drilling and completion carry owed to us by Total in our Barnett Shale joint venture, we agreed to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012. In January 2012, Chesapeake and Total agreed to reduce the minimum rig count from 12 to six rigs. In May 2012, Chesapeake and Total agreed to further reduce the minimum rig count from six to two rigs. We met this operated rig count commitment through December 31, 2012.

Property and Equipment Purchase Commitments

Much of the oilfield services equipment we purchase requires long production lead times. As a result, we have outstanding orders and commitments for such equipment. As of December 31, 2012, we had $118 million of purchase obligations related to future capital expenditures for drilling rigs and related equipment and hydraulic fracturing equipment in 2013.

Natural Gas and Liquids Purchase Commitments

We regularly commit to purchase natural gas and liquids from other owners in the properties we operate, including owners associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices. See Note 11 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

Under the terms of our joint venture agreements with Statoil and Total (see Note 11), we are required to extend, renew or replace certain expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas. We did not meet the net acreage maintenance commitment with Total under the terms of our Barnett Shale joint venture agreement as of the December 31, 2012 measurement date. We had a net acreage shortfall of approximately 13,000 net acres and will be required to make a cash payment of approximately $26 million to Total in the first half of 2013. The charge was recorded in impairments of fixed assets and other on the consolidated statement of operations. See Note 14 for further discussion of impairments.

Affiliate Commitments

Under our corporate revolving bank credit facility, certain of our subsidiaries, including our oilfield services companies, are not guarantors of the credit facility debt. Certain agreements between us and our subsidiaries, as described below, could affect the individual credit facility covenant calculations, but they would have no effect on the consolidated financial statements because the subsidiaries are wholly owned and consolidated. A payment from us to a non-guarantor subsidiary could affect our guarantor EBITDA, resulting in an impact to our corporate credit facility covenant compliance calculation. See Note 3 for discussion of our covenant calculation.

In October 2011, we entered into a services agreement with our wholly owned subsidiary, COO, under which we guarantee the utilization of a portion of COO's drilling rig and hydraulic fracturing fleets during the term of the agreement. Through October 2016, we are subject to monetary penalties if we do not operate a specific number of COO's drilling fleet or utilize a specific number of their hydraulic fracturing fleets. No payments were made pursuant to the services agreement in 2012 or 2011. Any payments made in future periods will eliminate in consolidation.

Other Commitments

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

In July 2011, we agreed to invest $150 million in newly issued convertible promissory notes of Clean Energy Fuels Corp. (Nasdaq:CLNE), based in Seal Beach, California. The investment is being made in three equal $50 million promissory notes, the first two of which were issued in July 2011 and July 2012, with the remaining note scheduled to be issued in June 2013. See Note 12 for further discussion of this investment.

In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Longmont, Colorado. As of December 31, 2012, we had funded $115 million of our commitment. The remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached by July 2013. See Note 12 for further discussion of this investment.

In December 2011, we sold Appalachia Midstream Services, L.L.C., a wholly owned subsidiary of our wholly owned subsidiary, Chesapeake Midstream Development, L.L.C. (CMD), to Chesapeake Midstream Partners, L.P. (now named Access Midstream Partners, L.P. (NYSE:ACMP)) for total consideration of $884 million. In addition, CMD has committed to pay ACMP for any quarterly shortfall between the actual adjusted EBITDA from the assets sold and specified quarterly targets, which total $100 million in 2012 and $150 million in 2013. We recorded this guarantee at an estimated fair value of $27 million at the time of the sale. No payment was required for 2012, and we recognized $8 million of gain associated with the release of the liability related to the quarterly targets achieved in 2012. The remaining $19 million fair value is included in other current liabilities on our consolidated balance sheet as of December 31, 2012. We will release this liability during 2013. To the extent CMD is required to make payments under the guarantee, we will record the differences between the liability and the associated payments in earnings.

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

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

Certain of our natural gas and oil properties are burdened by non-operating interests such as royalty and overriding royalty interests, including overriding royalty interests sold through our VPP transactions. As the holder of the working interest from which such interests have been created, we have the responsibility to bear the cost of developing and producing the reserves attributable to such interests. See Note 11 for further discussion of our VPP transactions.

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,		
	2012	2011	2010
		($ in millions)	
Current	$ 47	$ 13	$ —
Deferred	(427)	1,110	1,110
Total	$ (380)	$ 1,123	$ 1,110

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, 2012	2011	2010
	($ in millions)		
Income tax expense (benefit) at the federal statutory rate (35%)	$ (341)	$ 1,008	$ 1,009
State income taxes (net of federal income tax benefit)	(38)	74	78
Other	(1)	41	23
Total	$ (380)	$ 1,123	$ 1,110

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, 2012	2011
	($ in millions)	
Deferred tax liabilities:		
Natural gas and oil properties	$ (1,999)	$ (2,883)
Other property and equipment	(436)	(634)
Investments	—	(56)
Volumetric production payments	(1,432)	(1,453)
Contingent convertible debt	(416)	(396)
Deferred tax liabilities	(4,283)	(5,422)
Deferred tax assets:		
Net operating loss carryforwards	414	1,198
Derivative instruments	172	395
Asset retirement obligations	142	123
Investments	106	—
Deferred stock compensation	47	62
Accrued liabilities	90	82
Noncontrolling interest liabilities	178	114
Alternative minimum tax credits	225	257
State statutory depletion	137	121
Other	55	(29)
Deferred tax assets	1,566	2,323
Net deferred tax asset (liability)	(2,717)	(3,099)
Other non-current tax liabilities	—	(246)
Total deferred tax liabilities	$ (2,717)	$ (3,345)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 90	$ 139
Non-current deferred income tax liability	(2,807)	(3,484)
Total	$ (2,717)	$ (3,345)

As of December 31, 2012 and 2011, we classified $90 million and $139 million of deferred tax assets as current that were attributable to current temporary differences associated with accrued liabilities, derivative liabilities and other items. As of December 31, 2012 and 2011, non-current deferred tax liabilities on the consolidated balance sheets included net non-current deferred tax liabilities of $2.807 billion and $3.238 billion, respectively.

Deferred tax assets relating to tax benefits of employee share-based compensation have been reduced for stock options exercised and restricted stock that vested in periods in which Chesapeake was in a net operating loss (NOL) position. Some exercises and vestings result in tax deductions in excess of previously recorded benefits based on the stock option or restricted stock value at the time of grant (windfalls). Although these additional tax benefits or windfalls are reflected in NOL carryforwards in the tax return, the additional tax benefit associated with the windfalls is not recognized until the deduction reduces taxes payable pursuant to accounting for stock compensation under GAAP. Accordingly, since the tax benefit does not reduce Chesapeake's current taxes payable due to NOL carryforwards, these windfall tax benefits are not reflected in Chesapeake's NOLs in deferred tax assets. Windfalls included in NOL carryforwards but not reflected in deferred tax assets as of December 31, 2012 totaled $21 million. Any shortfalls resulting from tax deductions that were less than the previously recorded benefits were recorded as reductions to additional paid-in capital.

At December 31, 2012, Chesapeake had federal income tax NOL carryforwards of approximately $1.096 billion, which excludes the NOL carryforwards related to unrecognized tax benefits and stock compensation windfalls that have not been recognized under GAAP. Additionally, we had $51 million of AMT NOL carryforwards, net of unrecognized tax benefits, available as a deduction against future AMT income. The NOL carryforwards expire from 2025 through 2031. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income.

The ability of Chesapeake to utilize NOL carryforwards to reduce future federal taxable income and federal income tax is subject to various limitations under the Internal Revenue Code of 1986, as amended (the Code). 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 corporation 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 at the time of the ownership change. Certain NOLs acquired through various acquisitions are also subject to limitations.

The following table summarizes our NOLs as of December 31, 2012 and any related limitations:

	Total	Limited	Annual Limitation
		($ in millions)	
Net operating loss	$ 1,096	$ 64	$ 15
AMT net operating loss	$ 51	$ 51	$ 15

As of December 31, 2012, we do not believe that an ownership change has occurred. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

Accounting guidance for recognizing and measuring uncertain tax positions prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. As of December 31, 2012 and 2011, the amount of unrecognized tax benefits related to NOL carryforwards associated with uncertain tax positions and AMT associated with uncertain tax positions was $599 million and $369 million, respectively. If these unrecognized tax benefits are disallowed and we are required to pay additional AMT liabilities, any payments can be utilized as credits against future regular tax liabilities. If these unrecognized tax benefits are disallowed and our NOL carryforwards are reduced, the reduction will be offset by additional tax basis that will generate future deductions. The uncertain tax positions identified would not have a material effect on the effective tax rate. As of December 31, 2012, we had an accrued liability of $6 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:

	2012	2011	2010
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 369	$ 34	$ 231
Additions based on tax positions related to the current year	134	135	—
Additions to tax positions of prior years	96	200	(197)
Settlements	—	—	—
Unrecognized tax benefits at end of period	$ 599	$ 369	$ 34

Chesapeake's federal and state income tax returns are routinely audited by federal and state fiscal authorities. The Internal Revenue Service (IRS) is currently auditing our federal income tax returns for 2007 through 2011.

6. Related Party Transactions

Chief Executive Officer

As of December 31, 2012 and 2011, we had accrued accounts receivable from our Chief Executive Officer, Aubrey K. McClendon, of $23 million and $45 million, respectively, representing joint interest billings from December 2012 and 2011 related to Mr. McClendon's participation in Company wells pursuant to the Founder Well Participation Program (FWPP). These amounts were invoiced and timely paid in the following month. Since Chesapeake was founded in 1989, Mr. McClendon has acquired working interests in virtually all of our natural gas and oil properties by participating in our drilling activities under the terms of his employment agreement and the FWPP and predecessor participation arrangements provided for in Mr. McClendon's employment agreements. On April 30, 2012, the Company's Board of Directors and Mr. McClendon agreed to the early termination of the FWPP on June 30, 2014, 18 months before the end of the 10-year term approved by our shareholders in June 2005. Under the FWPP, 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. In conjunction with certain sales of natural gas and oil properties by the Company, affiliates of Mr. McClendon have sold interests in the same properties and on the same terms as those that applied to the interests sold by the Company, and the proceeds were paid to the sellers based on their respective ownership.

On December 31, 2008, we entered into a new five-year employment agreement with Mr. McClendon that contained a one-time well cost incentive award to him. The total cost of the award to Chesapeake was $75 million plus employment taxes in the amount of approximately $1 million. The incentive award was subject to a clawback equal to any unvested portion of the award if during the initial five-year term of the employment agreement, Mr. McClendon resigned from the Company or was terminated for cause by the Company. We are recognizing the incentive award as general and administrative expense over the five-year vesting period for the clawback resulting in an expense of approximately $15 million per year beginning in 2009. The net incentive award, after deduction of applicable withholding and employment taxes, of approximately $44 million was fully applied against costs attributable to interests in Company wells acquired by Mr. McClendon or his affiliates under the FWPP. On January 29, 2013, the Company announced that Mr. McClendon had agreed to retire from the Company on the earlier to occur of April 1, 2013 or the time at which his successor is appointed. Mr. McClendon's participation rights under the FWPP will continue through the expiration of the FWPP on June 30, 2014, and the incentive award clawback applicable to 2013 will not apply. See Note 21 for additional information on the terms of his separation from the Company.

In 2011, Chesapeake entered into a license and naming rights agreement with The Professional Basketball Club, LLC (PBC) for the arena in downtown Oklahoma City. PBC is the owner of the Oklahoma City Thunder basketball team, a National Basketball Association franchise and the arena's primary tenant. Mr. McClendon has a 19.2% equity interest in PBC. Under the terms of the agreement, Chesapeake has committed to pay fees ranging from $3 million to $4 million per year through 2023 for the arena naming rights and other associated benefits. In addition, since 2008, Chesapeake has been a founding sponsor of the Oklahoma City Thunder, initially under successive one-year contracts. In 2011, it entered into a 12-year sponsorship agreement, committing to pay an average annual fee of $3 million for advertising, use of an arena suite and other benefits. Chesapeake also has committed to purchase tickets to all 2012-2013 home games. In 2012 and 2011, the Company paid PBC approximately $7 million and $6 million, respectively, for naming rights fees, sponsorship fees and game tickets, and for 2013, the amount payable for such 2012-2013 season fees and tickets is approximately $3 million, not including any amounts for playoff tickets.

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

Other Related Parties

During 2012 and 2011, our formerly 46%-owned affiliate, Chesapeake Midstream Partners, L.P., now named Access Midstream Partners, L.P. (NYSE:ACMP), provided us natural gas gathering and treating services in the ordinary course of business. In addition, there are agreements in place whereby we support ACMP in functions for which we are reimbursed. See Note 12 for discussion of the sale of our interest in ACMP. During 2012 and 2011, our transactions with ACMP included the following:

	Years Ended December 31,	
	2012	2011
	($ in millions)	
Amounts paid to ACMP:		
Gas gathering fees[(a)]	$ 624	$ 469
Amounts received from ACMP:		
Compressor rentals	80	60
Inventory purchases	91	93
Other services provided	88	91
Total amounts received from ACMP	$ 259	$ 244

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

As of December 31, 2012 and 2011, we had net receivables (payables) from (to) ACMP of $5 million and $2 million, respectively. In addition, in 2012 and 2011, we sold natural gas gathering systems and related equipment to ACMP. See Note 11 for further discussion.

During 2012, 2011 and 2010, our 30%-owned affiliate, FTS, provided us hydraulic fracturing and other services in the ordinary course of business. During 2012, 2011 and 2010, we paid FTS $480 million, $369 million and $89 million, respectively, for these services. As well operators, we are reimbursed by other working interest owners through the joint interest billing process for their proportionate share of these costs. In addition, during 2012 we purchased $73 million of equipment from FTS. As of December 31, 2012, 2011 and 2010, we had $42 million, $115 million and $30 million, respectively, due FTS for services provided and not yet paid.

7. Employee Benefit Plans

Our qualified 401(k) profit sharing plan (401(k) Plan) is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except certain employees of Chesapeake Appalachia, L.L.C. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) Plan accounts, subject to plan limits and those set by the IRS. Chesapeake matches employee contributions dollar for dollar (subject to a maximum contribution of 15% of an employee's base salary and performance bonus) with Chesapeake common stock purchased in the open market. The Company contributed $91 million, $72 million and $54 million to the 401(k) Plan in 2012, 2011 and 2010, respectively.

Chesapeake also maintains a nonqualified deferred compensation plan, the Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan (DC Plan). To be eligible to participate in the DC Plan, an active employee must have a base salary of at least $150,000, have an employment agreement with Chesapeake, have a hire date on or before the first business day in October immediately preceding the year in which the employee is able to participate, or be designated as eligible to participate. Additionally, the employee has to have made the maximum contribution allowable under the 401(k) Plan. Chesapeake matches 100% of employee contributions up to 15% of base salary and performance bonus in the aggregate for the DC Plan with Chesapeake common stock, and an employee who is at least age 55 may elect for the matching contributions to be made in any one of the investment options. The maximum compensation that can be deferred by employees under all Company deferred compensation plans, including the Chesapeake 401(k) Plan, is a total of 75% of base salary and 100% of performance bonus. We contributed $16 million, $12 million and $9 million to the DC Plan during 2012, 2011 and 2010, respectively, to fund the match. In addition, in 2012 the Board of Directors adopted a Deferred Compensation Plan for Non-Employee Directors (Director DC Plan). The Company's non-employee directors are able to defer up to 100% of director cash compensation into the Director DC Plan and invest in Chesapeake common stock, but the plan does not provide for Company matching contributions.

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 its wholly owned subsidiary, Chesapeake Appalachia, L.L.C. Participation in these plans is limited to existing employees who are union members and former employees who were union members. The Chesapeake Appalachia, L.L.C. benefit plans provide health care and life insurance benefits to eligible employees upon retirement. We account for these benefits on an accrual basis. As of December 31, 2012, the Company had accrued approximately $10 million in accumulated post-employment benefit liability.

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

Common Stock

The following is a summary of the changes in our common shares issued for 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Shares issued at January 1	660,888	655,251	648,549
Restricted stock issuances (net of forfeitures)	5,038	4,961	5,924
Stock option exercises	542	565	458
Preferred stock conversion	—	111	21
Convertible note exchanges	—	—	299
Shares issued at December 31	666,468	660,888	655,251

In 2010, we privately exchanged approximately $11 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 298,500 shares of our common stock valued at approximately $9 million. 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 $2 million loss (including a nominal amount of deferred charges associated with the exchanges).

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2012:

Preferred Stock Series	Issue Date	Liquidation Preference per Share	Holder's Conversion Right	Conversion Rate	Conversion Price	Company's Conversion Right From	Company's Market Conversion Trigger[(a)]
5.75% cumulative convertible non-voting	May and June 2010	$ 1,000	Any time	$ 37.0892	$ 26.9620	May 17, 2015	$ 35.0506
5.75% (series A) cumulative convertible non-voting	May 2010	$ 1,000	Any time	$ 35.8414	$ 27.9007	May 17, 2015	$ 36.2709
4.50% cumulative convertible	September 2005	$ 100	Any time	$ 2.2861	$ 43.7429	September 15, 2010	$ 56.8658
5.00% cumulative convertible (series 2005B)	November 2005	$ 100	Any time	$ 2.5876	$ 38.6454	November 15, 2010	$ 50.2390

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

The following reflects our preferred shares outstanding for 2012, 2011 and 2010:

	5.75%	5.75% (A)	4.5%	5.00% (2005B)	5.00% (2005)
			(in thousands)		
Shares outstanding at January 1, 2012 and December 31, 2012	1,497	1,100	2,559	2,096	—
Shares outstanding at January 1, 2011	1,500	1,100	2,559	2,096	—
Conversion of preferred shares into common stock	(3)	—	—	—	—
Shares outstanding at December 31, 2011	1,497	1,100	2,559	2,096	—
Shares outstanding at January 1, 2010	—	—	2,559	2,096	5
Preferred stock issuances	1,500	1,100	—	—	—
Conversion of preferred shares into common stock	—	—	—	—	(5)
Shares outstanding at December 31, 2010	1,500	1,100	2,559	2,096	—

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

Year of Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares
		(in thousands)	
2011	5.75%	3	111
2010	5% (series 2005)	5	21

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

Dividends

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

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

Stock-Based Compensation Plans

Under Chesapeake's Long Term Incentive Plan, restricted stock, stock options, stock appreciation rights, performance shares, performance share units 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 49,500,000 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 the plan after September 30, 2014. The plan has been approved by our shareholders. There were 170,151, 68,824 and 87,500 shares of restricted stock issued to our non-employee directors from the plan in 2012, 2011 and 2010, respectively. Additionally, there were 5.0 million, 4.5 million and 5.8 million restricted shares issued, net of forfeitures, to employees and consultants during 2012, 2011 and 2010, respectively, from the plan. As of December 31, 2012, there were 10.7 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 the plan after April 14, 2013. The plan has been approved by our shareholders. There were a nominal amount, 0.4 million and 0.1 million restricted shares, net of forfeitures, issued during 2012, 2011 and 2010, respectively, from the plan. As of December 31, 2012, there were approximately 82,500 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 2012, 2011 and 2010, 30,000, 10,000 and 10,000 shares of common stock were awarded to new directors from the plan, respectively. As of December 31, 2012, there were no shares remaining available for issuance under the plan.

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

Name of Plan	Eligible Participants	Type of Options	Shares Covered	Shareholder Approved	Outstanding Options at December 31, 2012
2002 and 2001 Stock Option Plans	Employees and consultants	Incentive and nonqualified	3,000,000/ 3,200,000	Yes	84,584
2002 and 2001 Nonqualified Stock Option Plans	Employees and consultants	Nonqualified	4,000,000/ 3,000,000	No	175,466
2000 and 1999 Employee Stock Option Plans	Employees and consultants	Nonqualified	3,000,000 (each Plan)	No	22,163
1996 and 1994 Stock Option Plans	Employees and consultants	Incentive and nonqualified	6,000,000/ 4,886,910	Yes	16,049

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is generally four years from the date of grant for employees and three years for non-employee directors. To the extent compensation cost relates to employees directly involved in natural gas and oil acquisition, exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expense, natural gas, oil and NGL production expenses, marketing, gathering and compression expenses or oilfield services expense. Note 1 details the accounting for our stock-based compensation expense in 2012, 2011 and 2010.

A summary of the status of the unvested shares of restricted stock and changes during 2012, 2011 and 2010 is presented below.

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
	(in thousands)	
Unvested shares as of January 1, 2012	19,544	$ 26.97
Granted	9,480	$ 21.13
Vested	(8,620)	$ 28.08
Forfeited	(1,505)	$ 24.57
Unvested shares as of December 31, 2012	18,899	$ 23.72
Unvested shares as of January 1, 2011	21,375	$ 28.68
Granted	9,541	$ 28.38
Vested	(10,401)	$ 31.76
Forfeited	(971)	$ 27.28
Unvested shares as of December 31, 2011	19,544	$ 26.97
Unvested shares as of January 1, 2010	19,225	$ 31.89
Granted	9,061	$ 24.19
Vested	(5,900)	$ 31.99
Forfeited	(1,011)	$ 30.05
Unvested shares as of December 31, 2010	21,375	$ 28.68

The aggregate intrinsic value of restricted stock vested during 2012 was approximately $174 million based on the stock price at the time of vesting.

As of December 31, 2012, there was $289 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of approximately 2.4 years.

The vesting of certain restricted stock grants could result in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the years ended December 31, 2012, 2011 and 2010, we recognized reductions in tax benefits related to restricted stock of $32 million, $23 million, and $15 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

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 vest over a four-year period. As of December 31, 2012, all of our outstanding stock options were fully vested and exercisable.

The following table provides information related to stock option activity for 2012, 2011 and 2010:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)]
	(in thousands)			($ in millions)
Outstanding at January 1, 2012	1,051	$ 9.84	1.41	$ 13
Exercised	(570)	$ 7.45		$ 7
Outstanding and exercisable at December 31, 2012	481	$ 12.69	0.96	$ 2
Outstanding at January 1, 2011	1,808	$ 8.90	2.03	$ 31
Exercised	(757)	$ 7.59		$ 15
Outstanding and exercisable at December 31, 2011	1,051	$ 9.84	1.41	$ 13
Outstanding at January 1, 2010	2,283	$ 8.36	2.75	$ 40
Exercised	(475)	$ 6.29		$ 8
Outstanding and exercisable at December 31, 2010	1,808	$ 8.90	2.03	$ 31

(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, 2012, there was no remaining unrecognized compensation cost related to stock options.

During each of the years ended December 31, 2012 and 2010, we recognized excess tax benefits related to stock options of $2 million. During the year ended December 31, 2011, we recognized a reduction in tax benefits related to stock options of $3 million. All amounts were recorded as adjustments to additional paid-in capital and deferred income taxes.

The following table summarizes information about stock options outstanding and exercisable at December 31, 2012:

Range of Exercise Price	Number of Options	Weighted-Avg. Remaining Contractual Life in Years	Weighted-Avg. Exercise Price
	(in thousands)		
$ 7.80 — $ 9.57	43	0.04	$ 7.83
10.08 — 10.08	195	0.47	10.08
10.10 — 12.83	58	0.79	11.79
13.35 — 13.35	23	1.25	13.35
13.37 — 13.37	23	1.01	13.37
13.58 — 13.58	1	1.00	13.58
15.06 — 15.06	25	1.50	15.06
15.47 — 15.47	38	2.01	15.47
16.08 — 16.08	25	1.75	16.08
22.49 — 22.49	50	2.25	22.49
$ 7.80 — $ 22.49	481	0.96	$ 12.69

Performance Share Units

In January 2012, we granted performance share units (PSUs) to senior management under our Long Term Incentive Plan that include both an internal performance measure and an external market condition and that vest over one-, two- and three-year performance periods. The internal performance measure is considered a performance condition with a fair value generally equal to the Company's stock price. The external market condition is considered a market condition and generally requires Monte Carlo simulation to determine the fair value. The latter calculation is based on the absolute total shareholder return (TSR) of Chesapeake common stock and the relative TSR of Chesapeake common stock compared to the TSR of certain peers.

The payout for each PSU component can range from 0% to 125%, and therefore the range of payout under a PSU award is between 0% and 250%. Awards are payable in cash at the end of each performance period. We account for PSUs under FASB ASC Topic 718 because they include a market-based performance component. They are classified as a liability in our consolidated financial statements and are required to be measured at fair value as of the grant date, with such value re-measured at the end of each reporting period. Compensation expense is recognized over the vesting period with a corresponding adjustment to the liability. Because our PSUs vest over a three-year period, we have classified some of the liability as short-term and the rest as long-term on our consolidated balance sheet.

As of the grant date, the fair value of the 1,271,240 PSUs issued was $35 million. As of December 31, 2012, the fair value of the awards had decreased to $18 million. We have recorded $2 million of this value as a short-term liability for vested PSUs and $12 million as a long-term liability representing the portion of the award for which the requisite service period has been completed. The remaining $4 million relates to unvested PSUs for which the requisite service period has not been completed.

Noncontrolling Interests

Cleveland Tonkawa Financial Transaction. We formed CHK Cleveland Tonkawa, L.L.C. (CHK C-T) in March 2012 to continue development of a portion of our natural gas and oil assets in our Cleveland and Tonkawa plays. CHK C-T is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including under our indentures. In exchange for all of the common shares of CHK C-T, we contributed to CHK C-T approximately 245,000 net acres of leasehold and the existing wells within an area of mutual interest in the Cleveland and Tonkawa plays covering Ellis and Roger Mills counties in western Oklahoma. In March 2012, in a private placement, third-party investors contributed $1.25 billion in cash to CHK C-T in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest (ORRI) in the existing wells and up to 1,000 new net wells to be drilled on certain of our Cleveland and Tonkawa play leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK C-T limited liability company agreement (the CHK C-T LLC Agreement), as the holder of all the common shares and the sole managing member of CHK C-T, we maintain voting and managerial control of CHK C-T and therefore include it in our consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $225 million to the ORRI obligation and $1.025 billion to the preferred shares based on estimates of fair values. The ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our consolidated balance sheet. Pursuant to the CHK C-T LLC Agreement, CHK C-T is currently required to retain an amount of cash (measured quarterly) equal to (i) the next two quarters of preferred dividend payments plus (ii) its projected operating funding shortfall for the next six months. The amount so retained, approximately $57 million as of December 31, 2012, is reflected as restricted cash on our consolidated balance sheet.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 6% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, any dividend amount is not paid in full for any quarter. As the managing member of CHK C-T, we may, at our sole discretion and election at any time after March 31, 2014, distribute certain excess cash of CHK C-T, as determined in accordance with the CHK C-T LLC Agreement. Any such optional distribution of excess cash is allocated 75% to the preferred shares (which is applied toward redemption of the preferred shares) and 25% to the common shares unless we have not met our drilling commitment at such time, in which case an optional distribution would be allocated 100% to the preferred shares (and applied toward redemption thereof). We may also, at our sole discretion and election, in accordance with the CHK C-T LLC Agreement, cause CHK C-T to redeem all or a portion of the CHK C-T preferred shares for cash. The preferred shares will be redeemed at a valuation equal to the greater of a 9% internal rate of return or a return on investment of 1.35x, in each case inclusive of dividends paid through redemption at the rate of 6% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to March 31, 2019, the optional redemption valuation will increase to provide a 15% internal rate of return to the investors. The preferred shares are redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of December 31, 2012, the redemption price and the liquidation preference were each $1,305 per preferred share.

We have committed to drill, for the benefit of CHK C-T in the area of mutual interest, a minimum of 37.5 net wells per six-month period through 2013, inclusive of wells drilled in 2012, and 25 net wells per six-month period in 2014 through 2016, up to a minimum cumulative total of 300 net wells. If we fail to meet the then-current cumulative drilling commitment in any six-month period, any optional cash distributions would be distributed 100% to the investors. If we fail to meet the then-current cumulative drilling commitment in two consecutive six-month periods, the then-applicable internal rate of return to investors at redemption would increase by 3% per annum. In addition, if we fail to meet the then-current cumulative drilling commitment in four consecutive six-month periods, the then-applicable internal rate of return to investors at redemption would be increased by an additional 3% per annum. Any such increase in the internal rate of return would be effective only until the end of the first succeeding six-month period in which we have met our then-current cumulative drilling commitment. CHK C-T is responsible for all capital and operating costs of the wells drilled for the benefit of the entity.

The CHK C-T investors' right to receive, proportionately, a 3.75% ORRI in up to 1,000 new net wells and the contributed wells, on our Cleveland and Tonkawa leasehold is subject to an increase to 5% on net wells drilled in any year following a year in which we do not meet our commitment to drill the wells subject to the ORRI obligation, which runs from 2012 through the first quarter of 2025. However, in no event would we deliver to investors more than a total ORRI of 3.75% in existing wells and 1,000 new net wells. If at any time we hold fewer net acres than would enable us to drill all then-remaining net wells on 160-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining net wells. We retain the right to repurchase the investors' right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining net wells once we have drilled a minimum of 867 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our natural gas and oil properties.

As of December 31, 2012, $1.015 billion was recorded as noncontrolling interests on our consolidated balance sheet representing the third-party investments in CHK C-T. For 2012, income of $57 million was attributable to the noncontrolling interests of CHK C-T. Under the development agreement, approximately 85 qualified net wells were added in 2012. Under the ORRI obligation, we delivered an ORRI in approximately 76 new net wells. For 2012, we met all commitments associated with the CHK C-T transaction.

Utica Financial Transaction. We formed CHK Utica, L.L.C. (CHK Utica) in October 2011 to develop a portion of our Utica Shale natural gas and oil assets. CHK Utica is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including under our indentures. In exchange for all of the common shares of CHK Utica, we contributed to CHK Utica approximately 700,000 net acres of leasehold and the existing wells within an area of mutual interest in the Utica Shale play covering 13 counties located primarily in eastern Ohio. During November and December 2011, in private placements, third-party investors contributed $1.25 billion in cash to CHK Utica in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3% ORRI in 1,500 net wells to be drilled on certain of our Utica Shale leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK Utica limited liability company agreement (the CHK Utica LLC Agreement), as the holder of all the common shares and the sole managing member of CHK Utica, we maintain voting and managerial control of CHK Utica and therefore include it in our consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $300 million to the ORRI obligation and $950 million to the preferred shares based on estimates of fair values. The ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our consolidated balance sheets. Pursuant to the CHK Utica LLC Agreement, CHK Utica is required to retain a cash balance equal to the next two quarters of preferred dividend payments. The amount reserved for paying such dividends, approximately $44 million, is reflected as restricted cash on our consolidated balance sheet as of December 31, 2012. In addition, pursuant to the CHK Utica LLC Agreement, with respect to any sales proceeds as defined by the agreement, CHK Utica is required to separately account for, and dedicate all of such sales proceeds to either (i) capital expenditures made by CHK Utica in connection with its assets or (ii) the redemption of CHK Utica preferred shares. As a result of the sale of non-core Utica Shale assets in 2012, the amount reserved for paying capital expenditures, approximately $155 million, is reflected as restricted cash in other long-term assets on our consolidated balance sheet as of December 31, 2012. See Note 11 for further discussion of the sale of non-core Utica Shale assets.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 7% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, any dividend amount is not paid in full for any quarter. If we fail to meet the then-current drilling commitment in any year, we must pay CHK Utica $5 million for each well we are short of such drilling commitment. As the managing member of CHK Utica, we may, at our sole discretion and election at any time after December 31, 2013, distribute certain excess cash of CHK Utica, as determined in accordance with the CHK Utica LLC Agreement. Any such optional distribution of excess cash is allocated 70% to the preferred shares (which is applied toward redemption of the preferred shares) and 30% to the common shares unless we have not met our drilling commitment during a liquidated damages period, in which case an optional distribution would be allocated 100% to the preferred shares (and applied toward redemption thereof). We may also, at our sole discretion and election, in accordance with the CHK Utica LLC Agreement, cause CHK Utica to redeem the CHK Utica preferred shares for cash, in whole or in part. The preferred shares will be redeemed at a valuation equal to the greater of a 10% internal rate of return or a return on investment of 1.4x, in each case inclusive of dividends paid at the rate of 7% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to October 31, 2018, the optional redemption valuation will increase to the greater of a 17.5% internal rate of return or a return on investment of 2.0x. The preferred shares are redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of December 31, 2012, the redemption price and the liquidation preference were each approximately $1,322 per preferred share.

We have committed to drill, for the benefit of CHK Utica in the area of mutual interest, a minimum of 50 net wells per year from 2012 through 2016, up to a minimum cumulative total of 250 net wells. CHK Utica is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. CHK Utica also receives its proportionate share of the benefit of the drilling carry associated with our joint venture with Total in the Utica Shale. See Note 11 for further discussion of the joint venture.

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

As of December 31, 2012 and 2011, $950 million was recorded as noncontrolling interests on our consolidated balance sheets representing the third-party investments in CHK Utica. For 2012 and 2011, income of approximately $88 million and $10 million was attributable to the noncontrolling interests of CHK Utica. Under the development agreement, approximately 66 qualified net wells were added in 2012. Under the ORRI obligation, we delivered an ORRI in approximately 34 new net wells. For 2012, we met our drilling commitment associated with the CHK Utica transaction, but did not meet our ORRI commitment. The ORRI will increase to 4% for wells drilled in 2013, and the ultimate number of wells in which we must assign an interest will be reduced accordingly.

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

In connection with the initial public offering of the Trust, we conveyed royalty interests to the Trust that entitle the Trust to receive (i) 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) that we receive from the production of hydrocarbons from 69 producing wells, and, (ii) 50% of the proceeds (after deducting certain post-production expenses and any applicable taxes) in 118 development wells that have been or will be drilled on approximately 45,400 gross acres (29,000 net acres) in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma. Pursuant to the terms of a development agreement with the Trust, we are obligated to drill, or cause to be drilled, the development wells at our own expense prior to June 30, 2016, and the Trust will not be responsible for any costs related to the drilling of the development wells or any other operating or capital costs of the Trust properties. In addition, we granted to the Trust a lien on our remaining interests in the undeveloped properties that are subject to the development agreement in order to secure our drilling obligation to the Trust, although the maximum amount that may be recovered by the Trust under such lien could not exceed $263 million initially and is proportionately reduced as we fulfill our drilling obligation over time. As of December 31, 2012, we had drilled or caused to be drilled 55 development wells, as calculated under the development agreement, and the maximum amount recoverable under the drilling support lien was approximately $140 million.

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

On November 7, 2012, the Trust declared a cash distribution of $0.63 per common unit and $0.22 per subordinated unit for the three-month period ended September 30, 2012 and covering production for the period from June 1, 2012 to August 31, 2012. The distribution paid to third-party unitholders on November 29, 2012 was approximately $15 million.

On August 10, 2012, the Trust declared a cash distribution of $0.61 per common unit and $0.48 per subordinated unit for the three-month period ended June 30, 2012 and covering production for the period from March 1, 2012 to May 31, 2012. The distribution paid to third-party unitholders on August 30, 2012 was approximately $14 million.

On May 10, 2012, the Trust declared a cash distribution of $0.66 per unit for the three-month period ended March 31, 2012 and covering production for the period from December 1, 2011 to February 29, 2012. The distribution paid to third-party unitholders on May 31, 2012 was approximately $15 million.

On February 8, 2012, the Trust declared a cash distribution of $0.73 per unit for the three-month period ended December 31, 2011 and covering production for the period from September 1, 2011 to November 30, 2011. The distribution paid to third-party unitholders on March 1, 2012 was approximately $17 million.

We have determined that the Trust constitutes a VIE and that Chesapeake is the primary beneficiary. As a result, the Trust is included in our consolidated financial statements. As of December 31, 2012 and 2011, $356 million and $381 million, respectively, were recorded as noncontrolling interests on our consolidated balance sheets representing the public unitholders' investment in common units of the Trust. For 2012 and 2011, approximately $35 million and $5 million of income was attributable to the Trust's noncontrolling interests in our consolidated statement of operations. See Note 13 for further discussion of VIEs.

Cardinal Gas Services, L.L.C. Cardinal Gas Services, L.L.C. (Cardinal), an unrestricted, non-guarantor consolidated subsidiary, was formed in December 2011 to acquire, develop, operate and own midstream assets in the Utica Shale. In exchange for the contribution of approximately $14 million in midstream assets to Cardinal, we received 66% of the outstanding membership units of Cardinal. In exchange for approximately $5 million, Total E&P USA, Inc. (Total) received 25% of the outstanding membership units and in exchange for approximately $2 million, CGAS Properties, L.P. (CGAS), an affiliate of EnerVest, Ltd., received 9% of the membership units. Each member was responsible for its proportionate share of capital costs. We determined that Cardinal constituted a VIE and that Chesapeake was the primary beneficiary. As a result, Cardinal was included in our consolidated financial statements until December 2012, and the contributions from Total and CGAS were recorded as noncontrolling interests. In December 2012, we sold our interest in this consolidated entity in connection with the sale of CMO. See Note 11. As of December 31, 2012 and 2011, the noncontrolling interest balances on the consolidated balance sheets associated with the contributions from Total and CGAS were $0 and approximately $7 million, respectively.

Wireless Seismic, Inc. We have a controlling 57% equity interest in Wireless Seismic, Inc. (Wireless), a privately owned company engaged in research, development and eventual production of wireless seismic systems and any related technology that deliver seismic information obtained from standard geophones in real time to laptop and desktop computers. As a result of our control, Wireless is included in our consolidated financial statements. As of December 31, 2012, $5 million was recorded as noncontrolling interests on our consolidated balance sheet representing third-party investments in Wireless. For 2012, $4 million of Wireless' loss was attributable to noncontrolling interests of Wireless in our consolidated statement of operations.

Big Star Crude Co., LLC. Oilfield Trucking Solutions, LLC, a wholly owned subsidiary of Chesapeake, entered into a joint venture to form Big Star Crude Co., LLC, which engages in commercial trucking. We have determined that Big Star is a VIE because our voting rights are disproportionate to our economic interests and the activities of the entity involve and are conducted on our behalf. We have also determined that Chesapeake is the primary beneficiary, since it has the power to direct the activities of this VIE, has the obligation to absorb losses and has the right to receive benefits from the VIE. As a result, Big Star is included in our consolidated financial statements. As of December 31, 2012, $1 million was recorded as noncontrolling interests on our consolidated balance sheets representing our joint venture partner's equity investment in Big Star. For 2012, a nominal amount of Big Star's loss was attributable to noncontrolling interests of Big Star in our consolidated statement of operations.

9. Derivative and Hedging Activities

Natural Gas, Oil and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. 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 prices to be received for our production. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives. As of December 31, 2012 and 2011, our natural gas, oil and NGL derivative instruments consisted 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.
- *Options*: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
- *Swaptions:* Chesapeake sells call swaptions to counterparties that allow them, on a specific date, to extend an existing fixed-price swap for a certain period of time.
- *Knockout Swaps*: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than a certain pre-determined knockout price.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a price differential to NYMEX from a specified delivery point. Our natural gas basis protection swaps typically have negative differentials to NYMEX. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. Our oil basis protection swaps 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, oil and NGL derivative instruments as of December 31, 2012 and 2011 are provided below.

	December 31, 2012		December 31, 2011	
	Volume	Fair Value	Volume	Fair Value
		($ in millions)		($ in millions)
Natural gas (tbtu):				
Fixed-price swaps	49	$ 24	—	$ —
Call options	193	(240)	1,357	(284)
Basis protection swaps	111	(15)	106	(42)
Total natural gas	353	(231)	1,463	(326)
Oil (mmbbl):				
Fixed-price swaps	28.1	68	14.9	15
Call options	73.8	(748)	94.7	(1,282)
Call swaptions	5.3	(13)	7.8	(53)
Basis protection swaps	5.5	—	—	—
Fixed-price knockout swaps	—	—	0.8	7
Total oil	112.7	(693)	118.2	(1,313)
Total estimated fair value		$ (924)		$ (1,639)

Pursuant to accounting guidance for derivatives and hedging, certain derivatives qualify for designation as cash flow hedges. Following this guidance, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk and locked-in gains and losses of settled designated derivative contracts, 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 recognized in natural gas, oil and NGL sales. Changes in the fair value of derivatives not designated as cash flow hedges that occur prior to their maturity (i.e., temporary fluctuations in value) are reported in the consolidated statements of operations within natural gas, oil and NGL sales. As of December 31, 2012, we did not have any natural gas or oil derivatives that were designated as cash flow hedges. Therefore, changes in the fair value of these derivatives are reported in the consolidated statement of operations. See further discussion below under *Cash Flow Hedges*.

The components of natural gas, oil and NGL sales for the years ended December 31, 2012, 2011 and 2010 are presented below.

	Years Ended December 31,		
	2012	2011	2010
		($ in millions)	
Natural gas, oil and NGL sales	$ 5,359	$ 5,259	$ 4,248
Gains (losses) on natural gas, oil and NGL derivatives	919	772	1,422
Gains (losses) on ineffectiveness of cash flow hedges	—	(7)	(23)
Total natural gas, oil and NGL sales	$ 6,278	$ 6,024	$ 5,647

Hedging Facility

We have a multi-counterparty secured hedging facility with 17 counterparties that have committed to provide approximately 6.4 tcfe of hedging capacity for natural gas, oil and NGL price derivatives and 6.4 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.0 billion under the terms of the facility. As of December 31, 2012, we had hedged under the facility 0.9 tcfe of our future production with price derivatives and 0.1 tcfe with basis derivatives. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and NGL price and basis derivatives with the counterparties. Our obligations under the multi-counterparty facility are secured by proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times at semi-annual collateral dates and 1.30 times in between those dates, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility, indentures and sale/leaseback arrangements. 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 derivatives. In addition, there are volume-based sub-limits for natural gas, oil and NGL derivative instruments. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain requirements are met including maintaining specified collateral coverage ratios as well as maintaining credit ratings with either of the designated rating agencies at or above current levels. The facility does not have a maturity date. Counterparties to the agreement have the right to cease entering into derivative instruments with the Company on a prospective basis as long as obligations associated with any existing transactions in the facility continue to be satisfied in accordance with the terms of the agreement.

Interest Rate Derivatives

To mitigate a portion of our exposure to volatility in interest rates related to our senior notes and bank credit facilities, we enter into interest rate derivatives. As of December 31, 2012 and 2011, our interest rate derivative instruments consisted of the following types of instruments:

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

The notional amount and the estimated fair value of our interest rate derivatives outstanding as of December 31, 2012 and 2011 are provided below.

	December 31, 2012		December 31, 2011	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate:				
Swaps	$ 1,050	$ (35)	$ 1,050	$ (42)
Swaptions	—	—	300	—
Totals	$ 1,050	$ (35)	$ 1,350	$ (42)

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense in the consolidated statements of operations. The components of interest expense for the years ended 2012, 2011 and 2010 are presented below.

	Years Ended December 31,		
	2012	2011	2010
	($ in millions)		
Interest expense on senior notes	$ 732	$ 653	$ 718
Interest expense on credit facilities	70	70	61
Interest expense on term loans	173	—	—
(Gains) losses on interest rate derivatives	(7)	14	(80)
Amortization of loan discount, issuance costs and other	89	39	36
Capitalized interest	(980)	(732)	(716)
Total interest expense	$ 77	$ 44	$ 19

We have terminated certain fair value hedges related to senior notes. Gains and losses related to these terminated hedges will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next eight years, we will recognize $20 million in net gains related to such transactions.

Foreign Currency Derivatives

In December 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. As a result, we reclassified a loss of $38 million from accumulated other comprehensive income to the consolidated statement of operations, $20 million of which related to the unwound notional amount and was included in losses on purchases or exchanges of debt, and $18 million of which related to future interest associated with the unwound principal and was included in interest expense. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay Chesapeake €11 million and Chesapeake pays the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €344 million and Chesapeake will pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swaps, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swaps are designated as cash flow hedges. The fair values of the cross currency swaps are recorded on the consolidated balance sheet as a liability of $20 million at December 31, 2012. The euro-denominated debt in long-term debt has been adjusted to $454 million at December 31, 2012 using an exchange rate of $1.3193 to €1.00.

Additional Disclosures Regarding Derivative Instruments and Hedging Activities

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

The following table presents the fair value and location of each classification of derivative instrument disclosed in the consolidated balance sheets as of December 31, 2012 and 2011 on a gross basis without regard to same-counterparty netting:

		Fair Value December 31,	
	Balance Sheet Location	2012	2011
		($ in millions)	
Asset Derivatives:			
Not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$ 110	$ 54
Commodity contracts	Long-term derivative instruments	5	1
Total		115	55
Liability Derivatives:			
Designated as hedging instruments:			
Foreign currency contracts	Long-term derivative instruments	(20)	(38)
Total		(20)	(38)
Not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(157)	(232)
Commodity contracts	Long-term derivative instruments	(882)	(1,462)
Interest rate contracts	Long-term derivative instruments	(35)	(42)
Total		(1,074)	(1,736)
Total derivative instruments		$ (979)	$ (1,719)

A consolidated summary of the effect of derivative instruments on the consolidated statements of operations for 2012, 2011 and 2010 is provided below, separating fair value, cash flow and undesignated derivatives.

Fair Value Hedges

For interest rate derivative instruments designated as fair value hedges, the fair values of the hedges are recorded on the consolidated balance sheets as assets or liabilities, with corresponding offsetting adjustments to the debt's carrying value. We have elected not to designate any of our qualifying interest rate derivatives as fair value hedges. Therefore, changes in the fair value of all of our interest rate derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported in the consolidated statements of operations within interest expense.

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

Fair Value Derivatives	Location of Gain (Loss)	Years Ended December 31, 2012	2011	2010
		($ in millions)		
Interest rate contracts	Interest expense	$ 8	$ 16	$ 20

We include the expense on the hedged item (i.e., fixed-rate borrowings) in the same line item – interest expense – as the offsetting gain or loss on the related interest rate swap listed above. For the years ended December 31, 2012, 2011 and 2010, this expense was $0, $23 million, and $19 million, respectively.

Cash Flow Hedges

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

	Years Ended December 31, 2012		2011		2010	
	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)					
Balance, beginning of period	$ (287)	$ (178)	$ (291)	$ (181)	$ 134	$ 84
Net change in fair value	10	6	368	228	364	226
Gains reclassified to income	(27)	(17)	(364)	(225)	(789)	(491)
Balance, end of period	$ (304)	$ (189)	$ (287)	$ (178)	$ (291)	$ (181)

Approximately $179 million of the $189 million of accumulated other comprehensive loss as of December 31, 2012 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges. Because the originally forecasted transactions are still expected to occur, these amounts are being recognized in earnings in the month the originally forecasted production occurs. As of December 31, 2012, we expect to transfer approximately $20 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. The remaining amount will be transferred by December 31, 2022. As of December 31, 2012, none of our open commodity derivative instruments were designated as a cash flow hedge.

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

Cash Flow Derivatives	Location of Gain (Loss)	Years Ended December 31, 2012	2011	2010
		($ in millions)		
Gain (Loss) Recognized in AOCI (Effective Portion):				
Commodity contracts	AOCI	$ —	$ 392	$ 386
Foreign currency contracts	AOCI	10	(24)	(22)
		$ 10	$ 368	$ 364
Gain (Loss) Reclassified from AOCI (Effective Portion):				
Commodity contracts	Natural gas, oil and NGL sales	$ 27	$ 402	$ 789
Foreign currency contracts	Interest expense	—	(18)	—
Foreign currency contracts	Loss on purchase of debt	—	(20)	—
		$ 27	$ 364	$ 789
Gain (Loss) Recognized in Income				
Commodity contracts:				
Ineffective portion	Natural gas, oil and NGL sales	$ —	$ (7)	$ (23)
Amount initially excluded from effectiveness testing	Natural gas, oil and NGL sales	—	22	4
		$ —	$ 15	$ (19)

Undesignated Derivatives

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

Derivative Contracts	Location of Gain (Loss)	Years Ended December 31, 2012	2011	2010
		($ in millions)		
Commodity contracts	Natural gas, oil and NGL sales	$ 892	$ 348	$ 629
Interest rate contracts	Interest expense	(1)	(12)	60
Total		$ 891	$ 336	$ 689

Credit Risk

Derivative instruments that enable us to manage our exposure to natural gas and oil prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment-grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. On December 31, 2012, our natural gas, oil and interest rate derivative instruments were spread among 12 counterparties. Additionally, counterparties to our multi-counterparty secured hedging facility described previously are required to secure their obligations in excess of defined thresholds. We use this facility for the majority of our natural gas, oil and NGL derivatives.

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

Net Capitalized Costs

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

	December 31, 2012	December 31, 2011
	($ in millions)	
Natural gas and oil properties:		
Proved	$ 50,172	$ 41,723
Unproved	14,755	16,685
Total	64,927	58,408
Less accumulated depreciation, depletion and amortization	(33,009)	(27,208)
Net capitalized costs	$ 31,918	$ 31,200

Unproved properties not subject to amortization at December 31, 2012, 2011 and 2010 consisted mainly of leasehold acquired through direct purchases of significant natural gas and oil property interests. We capitalized approximately $976 million, $727 million and $711 million of interest during 2012, 2011 and 2010, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full cost pool. We will continue to evaluate our unproved properties, and although the timing of the ultimate evaluation or disposition of the properties cannot be determined, we can expect the majority of our unproved properties not held by production to be transferred into the amortization base over the next five years.

Costs Incurred in Natural Gas and Oil Property Acquisition, Exploration and Development

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

	Years Ended December 31, 2012	2011	2010
	($ in millions)		
Acquisitions of properties:			
Proved properties	$ 332	$ 48	$ 243
Unproved properties	2,981	4,736	6,953
Exploratory costs	2,353	2,261	872
Development costs	6,733	5,497	4,741
Costs incurred[(a)(b)]	$ 12,399	$ 12,542	$ 12,809

(a) Exploratory and development costs are net of joint venture drilling and completion cost carries of $784 million, $2.570 billion and $1.151 billion in 2012, 2011 and 2010, respectively.

(b) Includes capitalized interest and asset retirement cost as follows:

	2012	2011	2010
Capitalized interest	$ 976	$ 727	$ 711
Asset retirement obligations	$ 32	$ 3	$ 2

In 2012, we invested approximately $1.035 billion, net of drilling and completion cost carries of $86 million, to convert 961 bcfe of PUDs to proved developed reserves.

Results of Operations from Natural Gas, Oil and NGL Producing Activities

Chesapeake's results of operations from natural gas, oil and NGL producing activities are presented below for 2012, 2011 and 2010. The following table includes revenues and expenses associated directly with our natural gas, oil and NGL producing activities. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our natural gas, oil and NGL operations.

	Years Ended December 31,		
	2012	2011	2010
	($ in millions)		
Natural gas, oil and NGL sales	$ 6,278	$ 6,024	$ 5,647
Natural gas, oil and NGL production expenses	(1,304)	(1,073)	(893)
Production taxes	(188)	(192)	(157)
Impairment of natural gas and oil properties	(3,315)	—	—
Depletion and depreciation	(2,507)	(1,632)	(1,394)
Imputed income tax provision[(a)]	404	(1,220)	(1,233)
Results of operations from natural gas, oil and NGL producing activities	$ (632)	$ 1,907	$ 1,970

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

Natural Gas, Oil and NGL Reserve Quantities

Chesapeake's petroleum engineers and independent petroleum engineering firms estimated all of our proved reserves as of December 31, 2012, 2011 and 2010. Independent petroleum engineering firms estimated an aggregate of 89%, 77% and 78% of our estimated proved reserves (by volume) as of December 31, 2012, 2011 and 2010, respectively, as set forth below.

	December 31,		
	2012	2011	2010
Ryder Scott Company, L.P.	44%	19%	6%
PetroTechnical Services, Division of Schlumberger Technology Corporation	24%	7%	7%
Netherland, Sewell & Associates, Inc.	21%	42%	58%
Lee Keeling and Associates, Inc.	—%	9%	7%

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

Developed natural gas, oil and NGL reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

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

Presented below is a summary of changes in estimated reserves for 2012, 2011 and 2010.

	Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (bcfe)
December 31, 2012				
Proved reserves, beginning of period	15,515	291.6	253.9	18,789
Extensions, discoveries and other additions	3,317	374.0	139.4	6,391
Revisions of previous estimates	(6,080)	(67.5)	(47.3)	(6,763)
Production	(1,129)	(31.3)	(17.6)	(1,422)
Sale of reserves-in-place	(704)	(75.5)	(31.7)	(1,347)
Purchase of reserves-in-place	14	4.2	0.6	42
Proved reserves, end of period[(a)]	10,933	495.5	297.3	15,690
Proved developed reserves:				
Beginning of period	8,578	124.0	130.6	10,106
End of period	7,174	162.9	132.1	8,944
Proved undeveloped reserves:				
Beginning of period	6,937	167.6	123.3	8,683
End of period	3,759	332.6	165.2	6,746

	Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (bcfe)
December 31, 2011				
Proved reserves, beginning of period	15,455	150.1	123.3	17,096
Extensions, discoveries and other additions	4,156	168.4	85.2	5,683
Revisions of previous estimates	(361)	(7.8)	60.6	(50)
Production	(1,004)	(17.0)	(14.7)	(1,194)
Sale of reserves-in-place	(2,754)	(2.6)	(1.2)	(2,776)
Purchase of reserves-in-place	23	0.5	0.7	30
Proved reserves, end of period[b]	15,515	291.6	253.9	18,789
Proved developed reserves:				
Beginning of period	8,246	84.2	64.0	9,143
End of period	8,578	124.0	130.6	10,106
Proved undeveloped reserves:				
Beginning of period	7,209	65.9	59.3	7,953
End of period	6,937	167.6	123.3	8,683
December 31, 2010				
Proved reserves, beginning of period[c]	13,510	124.0	—	14,254
Extensions, discoveries and other additions	4,678	47.6	22.3	5,098
Revisions of previous estimates	(445)	(3.6)	108.3	183
Production	(925)	(10.9)	(7.5)	(1,035)
Sale of reserves-in-place	(1,426)	(11.2)	—	(1,493)
Purchase of reserves-in-place	63	4.2	0.2	89
Proved reserves, end of period	15,455	150.1	123.3	17,096
Proved developed reserves:				
Beginning of period	7,859	78.8	—	8,331
End of period	8,246	84.2	64.0	9,143
Proved undeveloped reserves:				
Beginning of period	5,651	45.2	—	5,923
End of period	7,209	65.9	59.3	7,953

(a) Includes 91 bcf of natural gas, 4 mmbbls of oil and 9 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, 45 bcf of natural gas, 2 mmbbls of oil and 4 mmbbls of NGL of which are attributable to the noncontrolling interest holders.

(b) Includes 136 bcf of natural gas, 6 mmbbls of oil and 14 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, 67 bcf of natural gas, 3 mmbbls of oil and 7 mmbbls of NGL of which are attributable to the noncontrolling interest holders.

(c) Prior to 2010, NGL reserve volumes were recognized as a component of natural gas volumes.

During 2012, we acquired approximately 42 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $332 million, and we sold 1.347 tcfe of our proved reserves for approximately $2.381 billion. During 2012, we recorded downward revisions of 6.763 tcfe to the December 31, 2011 estimates of our reserves. Included in the revisions were 5.414 tcfe of downward revisions resulting from lower natural gas prices in 2012 and 1.349 tcfe of downward revisions resulting from changes to previous estimates. Lower prices decrease the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2012 were $2.76 per mcf and $94.84 per bbl before price differentials. Including the effect of price differential adjustments, the prices used in computing our reserves as of December 31, 2012 were $1.75 per mcf of natural gas, $91.78 per barrel of oil and $30.81 per barrel of NGL. The nonprice-related revisions were primarily the result of our continued execution of the Company's strategy to shift its drilling focus from natural gas to liquids-rich areas and to drill in the "core of the core" of its acreage positions. As rigs were reallocated, PUDs were removed from various non-core areas resulting in downward revisions. As of December 31, 2012, there were no PUDs that had remained undeveloped for five years or more.

During 2011, we acquired approximately 30 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $48 million, and we sold 2.776 tcfe of our proved reserves for approximately $2.612 billion, including divestitures related to our Fayetteville Shale assets, a VPP transaction and other non-core asset sales. During 2011, we recorded negative revisions of 50 bcfe to the December 31, 2010 estimates of our reserves. Included in the revisions were 273 bcfe of positive revisions to producing properties, offset by 337 bcfe of negative revisions associated with the deletion of PUD reserves no longer consistent with our development plans. In addition, we had 14 bcfe of positive revisions resulting from higher oil prices. Higher prices increase the economic lives of the underlying natural gas and oil properties and thereby increase the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2011 were $4.12 per mcf and $95.97 per bbl before price differentials. Including the effect of price differential adjustments, the prices used in computing our reserves as of December 31, 2011 were $3.19 per mcf of natural gas, $88.50 per bbl of oil and $40.38 per bbl of NGL.

During 2010, we acquired approximately 89 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $243 million and we sold 1.493 tcfe of our proved reserves for approximately $2.876 billion, including divestitures related to three VPP transactions, the sale of a portion of our Barnett Shale assets and other non-core asset sales. During 2010, we recorded positive revisions of 183 bcfe to the December 31, 2009 estimates of our reserves. Included in the revisions were 189 bcfe of positive revisions resulting from higher natural gas prices and 6 bcfe of downward revisions resulting from changes to previous estimates. The natural gas and oil prices used in computing our reserves as of December 31, 2010 were $4.38 per mcf and $79.42 per bbl before price differentials. Including the effect of price differential adjustments, the prices used in computing our reserves as of December 31, 2010 were $3.52 per mcf of natural gas, $75.17 per bbl of oil and $32.06 per bbl of NGL.

Standardized Measure of Discounted Future Net Cash Flows

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

Future cash inflows and future production and development costs as of December 31, 2012, 2011 and 2010 were determined by applying the average of the first-day-of-the-month prices for the 12 months of the year and year-end costs to the estimated quantities of natural gas, oil and NGL to be produced. Actual future prices and costs may be materially higher or lower than the prices and costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for such year. Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

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

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

	Years Ended December 31,		
	2012	2011	2010
	($ in millions)		
Future cash inflows	$ 73,754 [(a)]	$ 85,537 [(b)]	$ 69,616 [(c)]
Future production costs	(18,809)	(23,022)	(20,384)
Future development costs	(12,656)	(14,471)	(11,602)
Future income tax provisions	(9,824)	(12,266)	(6,859)
Future net cash flows	32,465	35,778	30,771
Less effect of a 10% discount factor	(17,799)	(20,148)	(17,588)
Standardized measure of discounted future net cash flows[(d)]	$ 14,666	$ 15,630	$ 13,183

(a) Calculated using prices of $2.76 per mcf of natural gas and $94.84 per bbl of oil, before field differentials.

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

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

(d) Excludes future cash inflows attributable to production volumes sold to VPP buyers and includes future cash outflows attributable to the costs of such production. See Note 11.

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

	Years Ended December 31,		
	2012	2011	2010
	($ in millions)		
Standardized measure, beginning of period[(a)]	$ 15,630	$ 13,183	$ 8,203
Sales of natural gas and oil produced, net of production costs[(b)]	(3,867)	(3,993)	(3,199)
Net changes in prices and production costs	(2,720)	512	3,337
Extensions and discoveries, net of production and development costs	11,115	9,139	5,580
Changes in future development costs	3,687	667	173
Development costs incurred during the period that reduced future development costs	1,046	680	717
Revisions of previous quantity estimates	(8,699)	(708)	199
Purchase of reserves-in-place	285	50	255
Sales of reserves-in-place	(3,246)	(2,083)	(2,235)
Accretion of discount	1,988	1,515	945
Net change in income taxes	1,142	(2,286)	(716)
Changes in production rates and other	(1,695)	(1,046)	(76)
Standardized measure, end of period[(a)(c)(d)]	$ 14,666	$ 15,630	$ 13,183

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

(b) Excluding gains (losses) on derivatives.

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

(d) The standardized measure of discounted future net cash flows does not include estimated future cash inflows attributable to future production of VPP volumes sold and does include estimated future cash outflows attributable to the costs of future production of VPP volumes sold.

11. Acquisitions and Divestitures

Acquisition of Bronco Drilling

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

The following table summarizes the assets acquired and liabilities assumed:

	As of June 6, 2011 ($ in millions)
Current assets	$ 53
Drilling rigs and equipment	290
Goodwill	28
Intangible assets	10
Other	16
Total assets acquired	397
Current liabilities	32
Long-term liabilities	1
Deferred income taxes	25
Total liabilities assumed	58
Net assets acquired	$ 339

The acquisition date fair value of the consideration transferred was $339 million in cash. We received carryover tax basis in Bronco's assets and liabilities because the acquisition was not a taxable transaction under the Internal Revenue Code. Based upon the purchase price allocation, a step-up in basis related to the assets acquired from Bronco resulted in a net deferred tax liability of approximately $25 million. We recorded goodwill of $28 million, which represents the amount of the consideration transferred in excess of the fair values assigned to the individual assets acquired and liabilities assumed. Goodwill is primarily attributable to operational and cost synergies expected to be realized from the acquisition by integrating Bronco's drilling rigs and assembled workforce and is included in other long-term assets on our consolidated balance sheets. Goodwill was assigned to drilling rig operations within our oilfield services segment which is discussed in Note 17. Goodwill recorded in the acquisition is not subject to amortization but is tested annually for impairment on October 1. None of the goodwill is deductible for tax purposes. See *Goodwill* in Note 1 for further discussion. The drilling rigs and equipment we acquired from Bronco are now owned by Nomac Drilling, L.L.C., a drilling subsidiary of COO.

Divestitures of Natural Gas and Oil Properties

During 2012 and 2011, we engaged in the asset sales transactions described below as well as other individually insignificant sales.

Permian Basin. In September and October 2012, we sold the vast majority of our Permian Basin assets, representing approximately 6% of our total proved reserves as of June 30, 2012 and 6% of our 2012 second quarter net production, in three separate transactions for total net cash proceeds of approximately $3.091 billion. Approximately $466 million of additional consideration was withheld subject to certain title, environmental and other standard contingencies. Following the closing, we received approximately $84 million of such consideration, including $45 million received subsequent to December 31, 2012, and we expect to receive the majority of the remaining contingent amount in 2013. Of the total proceeds, we allocated approximately $42 million to our Permian Basin midstream and other fixed assets. The remaining proceeds were allocated to our Permian Basin natural gas and oil properties.

We used the net proceeds received from these transactions to reduce the outstanding balance on our May 2012 term loans. See Note 3 for further discussion of the term loan repayments.

Chitwood Knox. In December 2012, we sold approximately 40,000 net acres of non-core leasehold in the Chitwood Knox play in Oklahoma for approximately $540 million in cash.

Non-Core Utica Shale. In August 2012, we sold approximately 72,000 net acres of non-core leasehold in the Utica shale play in Ohio to affiliates of EnerVest for approximately $358 million in cash.

Texoma Woodford. In April 2012, we sold approximately 60,000 net acres of leasehold in the Texoma Woodford play in Oklahoma to XTO Energy Inc., a subsidiary of Exxon Mobil Corporation (NYSE:XOM), for approximately $572 million in cash. The properties included approximately 25 mmcfe per day of current net production.

Fayetteville Shale. In March 2011, we sold all of our Fayetteville Shale assets in central Arkansas to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited (NYSE:BHP; ASX:BHP), for net proceeds of approximately $4.65 billion in cash. The properties sold consisted of approximately 487,000 net acres of leasehold, net production at closing of approximately 415 mmcfe per day and midstream assets consisting of approximately 420 miles of pipeline. Of the total proceeds received, $350 million was allocated to our Fayetteville Shale midstream assets and a $7 million gain was recorded on the divestiture of those assets. The remainder of the proceeds was allocated to our Fayetteville Shale natural gas and oil properties.

Under full cost accounting rules, we accounted for the sale of natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss as the sales did not involve a significant change in proved reserves or significantly alter the relationship between costs and proved reserves. In conjunction with certain of these transactions, affiliates of our Chief Executive Officer, Aubrey K. McClendon, sold interests in the same properties and on the same terms as those that applied to the interests sold by the Company, and the net proceeds were paid to the sellers based on their respective ownership. These interests were acquired through the FWPP as described in Note 6.

Joint Ventures

As of December 31, 2012, we had entered into seven significant joint ventures with other leading energy companies pursuant to which we sold a portion of our leasehold, producing properties and other assets located in seven different resource plays and received cash of $7.1 billion and commitments for future drilling and completion cost sharing totaling $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all leasing, drilling, completion, operations and marketing activities for the project. The carry obligations paid by a joint venture partner are for a specified percentage of our drilling and completion cost obligations. In addition, a joint venture partner is responsible for its proportionate share of drilling and completion costs as a working interest owner. We bill our joint venture partners for their drilling carry obligations at the same time we bill them and other joint working interest owners for their share of drilling costs as they are incurred. For accounting purposes, initial cash proceeds from these joint venture transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. The transactions are detailed below.

Primary Play	Joint Venture Partner[(a)]	Joint Venture Date	Interest Sold	Cash Proceeds Received at Closing	Total Drilling Carries		Total Cash and Drilling Carry Proceeds	Drilling Carries Remaining[(b)]
					($ in millions)			
Utica	TOT	December 2011	25.0%	$ 610	$ 1,422	(c)	$ 2,032	$ 1,153
Niobrara	CNOOC	February 2011	33.3%	570	697	(d)	1,267	463
Eagle Ford	CNOOC	November 2010	33.3%	1,120	1,080		2,200	—
Barnett	TOT	January 2010	25.0%	800	1,404	(e)	2,204	—
Marcellus	STO	November 2008	32.5%	1,250	2,125		3,375	—
Fayetteville	BP	September 2008	25.0%	1,100	800		1,900	—
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508	(f)	3,158	—
				$ 7,100	$ 9,036		$ 16,136	$ 1,616

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

(b) As of December 31, 2012.

(c) The Utica drilling carries cover 60% of our drilling and completion costs for Utica wells drilled and must be used by December 2018. We expect to fully utilize these drilling carry commitments prior to expiration. See Note 4 for further discussion of the Utica drilling carries.

(d) The Niobrara drilling carries cover 67% of our drilling and completion costs for Niobrara wells drilled and must be used by December 2014. We expect to fully utilize these drilling carry commitments prior to expiration.

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

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

During 2012, 2011 and 2010, our drilling and completion costs included the benefit of approximately $784 million, $2.570 billion and $1.151 billion, respectively, in drilling and completion carries paid by our joint venture partners.

During 2012, 2011 and 2010, as part of our joint venture agreements with CNOOC, TOT, STO and PXP, we sold interests in additional leasehold we acquired in the Niobrara, Eagle Ford, Marcellus, Barnett, Utica, Haynesville and Bossier shale plays to our joint venture partners for approximately $272 million, $511 million and $440 million, respectively. For accounting purposes, cash proceeds from these transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Volumetric Production Payments

From time to time, we have sold certain of our producing assets which are located in more mature producing regions through the sale of volumetric production payments (VPPs). A VPP is a limited-term overriding royalty interest in natural gas and oil reserves that (i) entitles the purchaser to receive scheduled production volumes over a period of time from specific lease interests; (ii) is free and clear of all associated future production costs and capital expenditures; (iii) is nonrecourse to the seller (i.e., the purchaser's only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain all production beyond the specified volumes, if any, after the scheduled production volumes have been delivered. For all of our VPP transactions, we have novated hedges to each of the respective VPP buyers and such hedges covered all VPP volumes sold. If contractually scheduled volumes exceed the actual volumes produced from the VPP wellbores that are attributable to the ORRI conveyed, either the shortfall will be made up from future production from these wellbores (or, at our option, from our retained interest in the wellbores) through an adjustment mechanism or the initial term of the VPP will be extended until all scheduled volumes, to the extent produced, are delivered from the VPP wellbores to the VPP buyer. We retain drilling rights on the properties below currently producing intervals and outside of producing well bores.

As the operator of the properties from which the VPP volumes have been sold, we have the responsibility to bear the cost of producing the reserves attributable to such interests, which we include as a component of production expenses and production taxes in our consolidated statements of operations in the periods such costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining the cost center ceiling for impairment purposes and in determining our standardized measure. Pursuant to SEC guidelines, the estimates used for purposes of determining the cost center ceiling and the standardized measure are based on current costs. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all.

We have committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

Our outstanding VPPs consist of the following:

				Volume Sold			
VPP #	Date of VPP	Division	Proceeds	Natural Gas	Oil	NGL	Total
			($ in millions)	(bcf)	(mmbbl)	(mmbbl)	(bcfe)
10	March 2012	Anadarko Basin Granite Wash	$ 744	87	3.0	9.2	160
9	May 2011	Mid-Continent	853	138	1.7	4.8	177
8	September 2010	Barnett Shale	1,150	390	—	—	390
6	February 2010	East Texas and Texas Gulf Coast	180	44	0.3	—	46
5	August 2009	South Texas	370	67	0.2	—	68
4	December 2008	Anadarko and Arkoma Basins	412	95	0.5	—	98
3	August 2008	Anadarko Basin	600	93	—	—	93
2	May 2008	Texas, Oklahoma and Kansas	622	94	—	—	94
1	December 2007	Kentucky and West Virginia	1,100	208	—	—	208
			$ 6,031	1,216	5.7	14.0	1,334

The volumes produced on behalf of our VPP buyers for the years ended December 31, 2012, 2011 and 2010 were as follows:

	Volume Produced in 2012			Volume Produced in 2011			Volume Produced in 2010		
VPP #	Natural Gas	Oil	NGL	Natural Gas	Oil	NGL	Natural Gas	Oil	NGL
	(bcf)	(mbbl)	(mbbl)	(bcf)	(mbbl)	(mbbl)	(bcf)	(mbbl)	(mbbl)
10	18	723.3	1,729.1	—	—	—	—	—	—
9	18	249.3	643.6	17	250.5	615.4	—	—	—
8	80	—	—	101	—	—	44	—	—
7	—	288.0	—	—	773.0	—	—	613.0	
6	5	23.9	—	6	27.0	—	6	43.2	—
5	9	27.3	—	11	35.9	—	15	53.3	—
4	12	64.2	—	14	75.1	—	16	86.1	—
3	9	—	—	11	—	—	13	—	—
2	11	—	—	13	—	—	13	—	—
1	15	—	—	16	—	—	18	—	—
	177	1,376.0	2,372.7	189	1,161.5	615.4	125	795.6	—

The volumes remaining to be delivered on behalf of our VPP buyers as of December 31, 2012 are as follows:

		Volume Remaining as of December 31, 2012			
VPP #	Term Remaining	Natural Gas	Oil	NGL	Total
	(in months)	(bcf)	(mmbbl)	(mmbbl)	(bcfe)
10	110	68	2.3	7.5	127
9	98	102	1.2	3.5	130
8	32	164	—	—	164
6	85	26	0.2	—	27
5	49	24	0.1	—	25
4	48	35	0.2	—	36
3	79	39	—	—	39
2	76	31	—	—	31
1	120	120	—	—	120
		609	4.0	11.0	699

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

In September 2012, to facilitate the sales process associated with our Permian Basin divestiture packages, we purchased the remaining reserves from our Permian Basin VPP (VPP #7), originally sold in June 2010, for $313 million. The reserves purchased totaled 28 bcfe and were subsequently sold to the buyers of our Permian Basin assets.

Midstream Divestitures

As of December 31, 2012, we had sold substantially all of our remaining midstream business as described below.

Chesapeake Midstream Operating. In December 2012, our wholly owned midstream subsidiary, CMD, sold its wholly owned subsidiary, CMO, which held a majority of our midstream business, to ACMP, for total consideration of $2.16 billion in cash, subject to post-closing adjustments. In connection with the sale, Chesapeake entered into new long-term agreements in which ACMP agreed to perform certain natural gas gathering and related services for us within specified acreage dedication areas in exchange for (i) cost-of-service based fees redetermined annually beginning January 2014 in the Niobrara and Marcellus shale plays, (ii) cost-of-service based fees redetermined annually beginning October 2013 for the wet gas gathering systems and January 2014 for the dry gas gathering systems in the Utica Shale play, (iii) tiered fees based on volumes delivered relative to scheduled volumes through 2015 and thereafter cost-of-service based fees redetermined annually in the Eagle Ford Shale play, and (iv) annual minimum volume commitments and a fixed fee per mmbtu of natural gas gathered, subject to an annual 2.5% rate escalation, through 2017 and thereafter tiered fees based on volumes delivered relative to scheduled volumes in the Haynesville Shale play. We recorded a $289 million pre-tax gain associated with this transaction.

Midstream Eagle Ford Oil Gathering Assets. In November 2012, we sold our oil gathering business and related assets in the Eagle Ford Shale to Plains Pipeline, L.P. for cash proceeds of approximately $115 million. Subsequent to December 31, 2012, we received an additional $10 million of proceeds upon satisfaction of a certain closing contingency. We recorded a $7 million pre-tax loss associated with this transaction that will adjust to a $3 million pre-tax gain with the receipt of the $10 million contingency payment in 2013. In connection with the sale, we entered into new gathering and transportation agreements covering acreage dedication areas.

Appalachia Midstream Services. In December 2011, CMD sold its wholly owned subsidiary, Appalachia Midstream Services, L.L.C. (AMS), which held substantially all of our Marcellus Shale midstream assets, to ACMP for total consideration of $884 million and recorded a gain of $439 million. At closing, we received cash of $605 million and 9,791,605 common units of ACMP that had a value at closing of $279 million. The stock consideration increased our ownership in ACMP from 42.3% to 46.1%. The assets sold included an approximate 47% ownership of an integrated system of assets that consist of 200 miles of pipeline in the Marcellus Shale. In addition, CMD has committed to pay ACMP any quarterly shortfall between the actual EBITDA from the assets sold and specified quarterly targets, which total $100 million in 2012 and $150 million in 2013. We have recorded the fair value of this guarantee as a liability. See Note 4 for further discussion of this commitment. We, and other producers in the area, have 15-year cost of service gathering and compression agreements with AMS that include significant acreage dedications and an annual fee redetermination.

Springridge Gas Gathering System. In December 2010, CMD sold its Springridge natural gas gathering system and related facilities in the Haynesville Shale to ACMP for $500 million and recorded a gain on the sale of $157 million. In connection with this transaction, ACMP and certain Chesapeake subsidiaries entered into ten-year gathering and compression agreements covering Chesapeake's and other producers' upstream assets within an area of dedication around the existing pipeline system. The gathering and compression agreements are similar to the previously existing gathering agreement between Chesapeake and ACMP and include a minimum volume commitment through 2013 and annual rate redetermination.

12. Investments

At December 31, 2012 and 2011, we had the following investments:

	Approximate Ownership %	Accounting Method	Carrying Value December 31, 2012	Carrying Value December 31, 2011
			($ in millions)	
FTS International, Inc.	30%	Equity	$ 298	$ 235
Chaparral Energy, Inc.	20%	Equity	141	143
Sundrop Fuels, Inc.	50%	Equity	111	34
Clean Energy Fuels Corp.	—	Cost	100	50
Twin Eagle Resource Management, LLC	30%	Equity	34	20
Maalt Specialized Bulk, LLC	49%	Equity	13	12
Clean Energy Fuels Corp.	1%	Fair Value	12	12
Gastar Exploration Ltd.	10%	Fair Value	8	22
Chesapeake Midstream Partners, L.P.[(a)]	—	Equity	—	987
Other	—	—	11	16
Total investments			$ 728	$ 1,531

(a) See *Sold Investments* below.

FTS International, Inc. FTS International, Inc. (FTS), based in Fort Worth, Texas, is a privately held company which, through its subsidiaries, provides hydraulic fracturing and other services to oil and gas companies.

In 2012, we recorded negative equity method adjustments, prior to intercompany profit eliminations, of $91 million for our share of FTS's net loss and recorded accretion adjustments of $45 million related to the excess of our underlying equity in net assets of FTS over our carrying value. We also funded a capital call of $3 million in 2012. The carrying value of our investment in FTS was less than our underlying equity in net assets by approximately $622 million as of December 31, 2012, of which $296 million was attributed to goodwill. The value attributed to goodwill decreased by $200 million during 2012, which represents our proportionate share, net of tax, of an impairment recorded by FTS related to its goodwill. The value not attributed to goodwill is being accreted over the nine-year estimated useful lives of the underlying assets.

In addition, in November 2012, we purchased our pro-rata share, equal to approximately $106 million, of preferred equity securities offered by FTS to existing stockholders. Each share of preferred stock is convertible into a specified number of shares of FTS common stock automatically upon a qualified initial public offering of FTS common stock and at our option at any time following the second anniversary of the issue date.

Chaparral Energy, Inc. Chaparral Energy, Inc., based in Oklahoma City, Oklahoma, is a private independent oil and natural gas company engaged in the production, acquisition and exploitation of oil and natural gas properties.

In 2012, we recorded a positive equity method adjustment of $4 million related to our share of Chaparral's net income, a $3 million charge related to our share of its other comprehensive income, and an amortization adjustment of $3 million related to our carrying value in excess of our underlying equity in net assets. The carrying value of our investment in Chaparral was in excess of our underlying equity in net assets by approximately $52 million as of December 31, 2012. This excess is attributed to the natural gas and oil reserves held by Chaparral and is being amortized over the estimated life of these reserves based on a unit of production rate.

Sundrop Fuels, Inc. In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Longmont, Colorado. The investment is being used to fund construction of a nonfood biomass-based “green gasoline” plant, capable of annually producing more than 40 million gallons of gasoline from natural gas and waste cellulosic material. The investment is intended to accelerate the development of an affordable, stable, room-temperature, natural gas-based fuel for immediate use in automobiles, diesel engine vehicles and aircraft. As of December 31, 2012, we had funded $115 million of our commitment, of which $80 million was funded in 2012. The remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached by July 2013. The full investment will represent approximately 50% of Sundrop Fuels’ equity on a fully diluted basis.

In 2012, we recorded a $3 million charge related to our share of Sundrop’s net loss. The carrying value of our investment in Sundrop was in excess of our underlying equity in net assets by approximately $53 million as of December 31, 2012. This excess will be amortized over the life of the plant, once it is placed into service.

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

In December 2011, we also purchased one million shares of Clean Energy common stock for $10 million and classified this investment as available-for-sale and reported it at fair value. During 2012, the carrying value of our investment remained the same as the common stock price of Clean Energy changed from $12.46 per share as of December 31, 2011 to $12.45 per share as of December 31, 2012. Through December 31, 2012, we had recorded a mark-to-market pre-tax gain of $2 million in accumulated other comprehensive income for this investment.

Twin Eagle Resource Management LLC. In 2010, we invested $20 million in Twin Eagle Resource Management LLC, a natural gas trading and management firm. During 2012, we invested an additional $19 million and we recorded a $5 million charge related to our share of Twin Eagle’s net loss.

Maalt Specialized Bulk, LLC. In 2011, PTL Prop Solutions, LLC, a wholly owned subsidiary of Chesapeake, invested $12 million in Maalt Specialized Bulk, LLC (Maalt), which engages in bulk transportation services of sand. In 2012, we funded an additional investment of $1 million related to Maalt meeting certain performance targets as outlined in our investment agreement.

Gastar Exploration Ltd. Gastar Exploration Ltd. (NYSE MKT:GST), based in Houston, Texas, is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. Our investment in Gastar has a cost basis of $89 million and is classified as available-for-sale, and reported at fair value. During 2012, the carrying value of our investment decreased as the common stock price of Gastar decreased from $3.18 per share as of December 31, 2011 to $1.21 per share as of December 31, 2012. In March 2009, we booked an other-than-temporary-impairment of $70 million, and, through December 31, 2012, we had recorded a mark-to-market pre-tax loss of $11 million in accumulated other comprehensive income for this investment.

Sold Investments

Chesapeake Midstream Partners, L.P. In June 2012, we sold all of our common and subordinated units representing limited partner interests in Chesapeake Midstream Partners, L.P., now named Access Midstream Partners, L.P. (NYSE:ACMP), and all of our limited liability company interests in the sole member of its general partner to funds affiliated with Global Infrastructure Partners for cash proceeds of $2.0 billion. We recorded a $1.032 billion gain associated with the transaction, including the recognition of a $13 million deferred gain related to equipment previously sold to ACMP.

During 2012, we recorded positive equity method adjustments of $46 million for our share of ACMP's income, received cash distributions of $56 million from ACMP and recorded accretion adjustments of $4 million related to our share of equity in excess of cost. See Note 13 for further discussion of ACMP.

Utica East Ohio Midstream, LLC. In March 2012, CMD entered into an agreement to form Utica East Ohio Midstream, LLC (UEOM) with M3 Midstream, L.L.C. and EV Energy Partners, L.P. to develop necessary infrastructure for the gathering and processing of natural gas and NGL in the Utica Shale play in eastern Ohio. We sold this investment in connection with the sale of CMO to ACMP in December 2012. See Note 11 for further discussion.

Ranch Westex, JV LLC. In December 2011, CMD entered into an agreement to form Ranch Westex JV, LLC with two other parties to develop, construct and operate necessary infrastructure for the processing and gathering of natural gas in Ward County, Texas. We sold this investment in connection with the sale of CMO to ACMP in December 2012. See Note 11 for further discussion.

Glass Mountain Pipeline, LLC. In April 2012, CMD entered into an agreement with two other parties to form Glass Mountain Pipeline, LLC to construct a 210 mile pipeline in western and north central Oklahoma in which CMD had a 50% ownership interest. In 2012, CMD sold its interest for $99 million and recorded a gain of $62 million.

13. Variable Interest Entities

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

Consolidated VIE

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

The Trust is a consolidated entity whose legal existence is separate from Chesapeake and our other consolidated subsidiaries and the Trust is not a guarantor of any of Chesapeake's debt. The creditors or beneficial holders of the Trust have no recourse to the general credit of Chesapeake; however, we have certain obligations to the Trust through the development agreement that are secured by a drilling support lien on our retained interest in the development wells up to a specified maximum amount recoverable by the Trust, which could result in the Trust acquiring all or a portion of our retained interest in the undeveloped portion of an area of mutual interest, if we do not meet our drilling commitment. In consolidation, as of December 31, 2012, approximately $430 million of net natural gas and oil properties, $21 million of current liabilities, $1 million of cash and cash equivalents, $4 million of short-term derivative liabilities and $3 million of long-term derivative liabilities were attributable to the Trust. We have presented parenthetically on the face of the consolidated balance sheets the assets of the Trust that can be used only to settle obligations of the Trust and the liabilities of the Trust for which creditors do not have recourse to the general credit of Chesapeake.

Unconsolidated VIE

Mineral Acquisition Company I, L.P. In 2012, MAC-LP, L.L.C., a wholly owned non-guarantor unrestricted subsidiary of Chesapeake, entered into a partnership agreement with KKR Royalty Aggregator LLC (KKR) to form Mineral Acquisition Company I, L.P. The purpose of the partnership is to acquire mineral interests, or royalty interests carved out of mineral interests, in oil and natural gas basins in the continental United States. We are committed to acquire for our own account (outside the partnership) 10% of any acquisition agreed upon by the partnership up to a maximum of $25 million, and the partnership will acquire the remaining 90% up to a maximum of $225 million, funded entirely by KKR, making KKR the sole equity investor. We have significant influence over the decisions made by the partnership, as we hold two of five seats on the board of directors. We will receive proportionate distributions from the partnership of any cash received from royalties in excess of expenses paid, ranging from 7% to 22.5%. The partnership is considered a VIE because KKR's control over the partnership is disproportionate to its economic interest. This VIE remains unconsolidated as the power to direct the activities of the partnership is shared between the Company and KKR. We are using the equity method to account for this investment.

14. Net Gains on Sales of Fixed Assets and Impairments of Fixed Assets and Other

Net Gains on Sales of Fixed Assets

For assets outside of our full cost pool, the costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from accounts, and the resulting gain or loss is reflected in operating costs. A summary of our gains or losses by asset class for the years ended December 31, 2012, 2011 and 2010 is as follows:

	Years Ended December 31,		
	2012	2011	2010
		($ in millions)	
Gathering systems and treating plants	$ 286	$ 440	$ 139
Drilling rigs and equipment	(10)	(1)	(1)
Buildings and land	(7)	(2)	(3)
Other	(2)	—	2
Total net gains on sales	$ 267	$ 437	$ 137

The net gains on sales of gathering systems and treating plants were primarily from the sale of our midstream subsidiary CMO to ACMP in 2012, the sale of our midstream subsidiary AMS to ACMP in 2011 and the sale of our Springridge gas gathering system to ACMP in 2010. See Note 11 for further discussion of these transactions.

Impairments of Fixed Assets and Other

We test our long-lived assets other than natural gas and oil properties for recoverability whenever events or changes in circumstances indicate that carrying amounts may not be recoverable and recognize an impairment loss if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. In 2012, 2011 and 2010, we determined that certain of our property, plant and equipment were being carried at values that were not recoverable and in excess of fair value. A summary of impairments by asset class for the years ended December 31, 2012, 2011 and 2010 is as follows:

	Years Ended December 31,		
	2012	2011	2010
		($ in millions)	
Buildings and land	$ 248	$ 3	$ —
Drilling rigs and equipment	60	—	—
Gathering systems and treating plants	6	43	21
Other	26	—	—
Total impairments	$ 340	$ 46	$ 21

Buildings and Land. In 2012 and 2011, we recognized $248 million and $3 million of impairment losses, respectively, primarily associated with an office building and surface land located in our Barnett Shale operating area. Due to depressed natural gas prices during 2012 and a shift to a more liquids-focused drilling program, we have significantly reduced our Barnett Shale operations. The change in business climate related to the Barnett Shale required us to test these long-lived assets for recoverability in 2012. We have a purchase offer from a third party that we used to determine the fair value of the office building and measured the fair value of the surface land using prices from orderly sales transactions for comparable properties between market participants. The office building and surface land are included in our other operating segment.

Drilling Rigs and Equipment. As our strategic focus is shifting from a natural gas asset base to a more balanced natural gas and liquids asset base, and as our budgeted capital expenditures are being reduced, our active rig count has decreased significantly with a corresponding increase in the number of idle rigs we own or lease. In 2012, we negotiated the purchase of 25 rigs previously sold in our sale leaseback transactions described in Note 4 from various lessors for an aggregate price of $61 million, of which $25 million was deemed to be early lease termination costs and was recognized as impairments of fixed assets and other in the consolidated statement of operations.

In 2012, we recognized $26 million of impairment losses on certain of our owned drilling rigs due to the expectation that these particular drilling rigs would have insufficient cash flow to recover their carrying values in the business climate due to depressed natural gas prices. We estimated the fair value of the drilling rigs using prices that would be received to sell each rig in an orderly transaction between market participants. Also in 2012, we recognized $9 million of impairment losses primarily related to drill pipe and other equipment. The drilling rigs and equipment are included in our oilfield services operating segment.

Gathering Systems and Treating Plants. In 2012, 2011 and 2010, we recognized impairments of $6 million, $43 million and $21 million, respectively, related to certain of our midstream assets. The gathering systems and treating plants are included in our marketing, gathering and compression operating segment.

Other. In 2012, we recorded a $26 million charge related to the shortfall of our net acreage maintenance commitment with Total in the Barnett Shale. See *Net Acreage Maintenance Commitments* in Note 4 for further discussion.

15. Fair Value Measurements

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

Recurring Fair Value Measurement

Other Current Assets. Current assets related to forfeited 401(k) employee contributions are invested in traded securities.

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

Other Long-Term Assets and Liabilities. Assets and liabilities related to Chesapeake's deferred compensation plan are included in other long-term assets and other long-term liabilities, respectively. The fair values of these assets and liabilities are determined using quoted market prices, as the plan consists of exchange-traded mutual funds and company common stock.

Derivatives. The fair value of our derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as natural gas and oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by our counterparties for reasonableness. Since natural gas, oil, NGL, interest rate and cross currency swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. All other derivatives have some level of unobservable input, such as volatility curves, and are therefore classified as Level 3. Derivatives are also subject to the risk that either party to a contract will be unable to meet its obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date, this has not had a material impact on the values of our derivatives.

Debt. The fair value of certain of our long-term debt is based on the face amount of that debt along with the value of related designated fair value interest rate swaps. We currently do not have any debt recorded at fair value since we have no open fair value hedges.

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2012:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
	($ in millions)			
Financial Assets (Liabilities):				
Other current assets	$ 4	$ —	$ —	$ 4
Investments	20	—	—	20
Other long-term assets	88	—	—	88
Other long-term liabilities	(87)	—	—	(87)
Derivatives:				
Commodity assets	—	105	10	115
Commodity liabilities	—	(13)	(1,026)	(1,039)
Interest rate liabilities	—	(35)	—	(35)
Foreign currency liabilities	—	(20)	—	(20)
Total derivatives	—	37	(1,016)	(979)
Total	$ 25	$ 37	$ (1,016)	$ (954)

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

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
	($ in millions)			
Financial Assets (Liabilities):				
Investments	$ 34	$ —	$ —	$ 34
Other long-term assets	61	—	—	61
Other long-term liabilities	(62)	—	—	(62)
Derivatives:				
Commodity assets	—	46	9	55
Commodity liabilities	—	(31)	(1,663)	(1,694)
Interest rate liabilities	—	(42)	—	(42)
Foreign currency liabilities	—	(38)	—	(38)
Total derivatives	—	(65)	(1,654)	(1,719)
Total	$ 33	$ (65)	$ (1,654)	$ (1,686)

A summary of the changes in Chesapeake's financial assets (liabilities) classified as Level 3 measurements during 2012 and 2011 is presented below.

	Derivatives			
	Commodity	Interest Rate	Foreign Currency	Debt
	($ in millions)			
Beginning Balance as of January 1, 2012	$ (1,654)	$ —	$ —	$ —
Total gains (losses) (realized/unrealized):				
Included in earnings[(a)]	567	6	—	—
Total purchases, issuances, sales and settlements:				
Sales	—	(6)	—	—
Settlements	71	—	—	—
Ending Balance as of December 31, 2012	$ (1,016)	$ —	$ —	$ —
Beginning Balance as of January 1, 2011	$ (1,954)	$ (69)	$ (43)	$ (1,371)
Total gains (losses) (realized/unrealized):				
Included in earnings[(a)]	113	23	—	—
Total purchases, issuances, sales and settlements:				
Sales	(1)	(8)	—	—
Settlements	188	—	—	—
Transfers in and out of Level 3[(b)]	—	54	43	1,371
Ending Balance as of December 31, 2011	$ (1,654)	$ —	$ —	$ —

(a)

	Natural Gas, Oil and NGL Sales		Interest Expense	
	2012	2011	2012	2011
	($ in millions)			
Total gains (losses) included in earnings for the period	$ 567	$ 113	$ 6	$ 23
Change in unrealized gains (losses) relating to assets still held at reporting date	$ 374	$ (263)	$ —	$ —

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

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

The significant unobservable inputs for Level 3 derivative contracts include unpublished forward prices of natural gas and oil, market volatility and credit risk of counterparties. Changes in these inputs will impact the fair value measurement of our derivative contracts. For example, an increase (decrease) in the forward prices and volatility of natural gas and oil prices will decrease (increase) the fair value of natural gas and oil derivatives and adverse changes to our counterparties' creditworthiness will decrease the fair value of our derivatives.

Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value December 31, 2012
				($ in millions)
Oil Trades[(a)]	Oil price volatility curve	15.79% - 28.74%	21.94%	$ (761)
Oil Basis Swaps[(b)]	Physical pricing point forward curves	$8.21 - $18.49	$ 13.23	$ —
Natural Gas Trades[(a)]	Natural gas price volatility curve	20.93% - 39.44%	22.45%	$ (240)
Natural Gas Basis Swaps[(b)]	Physical pricing point forward curves	($1.73) - $0.02	$ (0.20)	$ (15)

(a) Fair value is based on an estimate derived from option models.

(b) Fair value is based on an estimate of discounted cash flows.

Nonrecurring Fair Value Measurements

Fair value measurements were applied with respect to our non-financial assets, measured on a nonrecurring basis, to determine impairments. These assets consist primarily of land, buildings, drilling rigs and drill pipe. We have either received a bid from a third party or used a third party to assess the fair value of these assets. Since the inputs used are not observable in the market, these assets are classified as Level 3 in the fair value hierarchy. See Note 14 for additional discussion.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. The carrying values of financial instruments comprising cash and cash equivalents, restricted cash, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our exchange-traded debt using quoted market prices (Level 1). The fair value of all other debt, which consists of our credit facilities and our term loans, is estimated using our credit default swap rate (Level 2). Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	December 31, 2012		December 31, 2011	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Current maturities of long-term debt (Level 1)	$ 463	$ 480	$ —	$ —
Long-term debt (Level 1)	$ 9,759	$ 10,457	$ 8,849	$ 9,709
Long-term debt (Level 2)	$ 2,378	$ 2,284	$ 1,749	$ 1,690

16. Asset Retirement Obligations

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

	Years Ended December 31,	
	2012	2011
	($ in millions)	
Asset retirement obligations, beginning of period	$ 323	$ 301
Additions	29	20
Revisions[(a)]	42	(1)
Settlements and disposals	(41)	(16)
Accretion expense	22	19
Asset retirement obligations, end of period	$ 375	$ 323

(a) Revisions in estimated liabilities can result from changes in estimated service and equipment costs, changes in the estimated timing of settling asset retirement obligations and changes in estimated inflation rates. In 2012, we revised our asset retirement obligations related to natural gas and oil properties based on an increase in estimated service and equipment costs and changes to the estimated timing of settling the asset retirement obligations.

17. Major Customers and Segment Information

Sales to Plains Marketing, L.P. constituted 11% of our total natural gas, oil and NGL revenues (before the effects of hedging) for the year ended December 31, 2012. There were no sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) for the years ended December 31, 2011 and 2010.

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

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

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of natural gas, oil and NGL related to Chesapeake's ownership interests by the marketing, gathering and compression operating segment are reflected as exploration and production revenues. Such amounts totaled \$5.5 billion, \$5.2 billion and \$4.2 billion for the years ended December 31, 2012, 2011 and 2010, respectively. The following table presents selected financial information for Chesapeake's operating segments.

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)			
For the Year Ended December 31, 2012:						
Revenues	$ 6,278	$ 10,895	$ 1,917	$ 21	$ (6,795)	$ 12,316
Intersegment revenues	—	(5,464)	(1,315)	(16)	6,795	—
Total revenues	$ 6,278	$ 5,431	$ 602	$ 5	$ —	$ 12,316
Unrealized (gain) loss on natural gas, oil and NGL derivatives	(561)	—	—	—	—	(561)
Depreciation, depletion and amortization	2,624	54	232	46	(145)	2,811
Impairment of natural gas and oil properties	3,315	—	—	—	—	3,315
(Gains) losses on sales of fixed assets	14	(298)	10	7	—	(267)
Impairments of fixed assets and other	28	6	60	246	—	340
Interest expense	(47)	(20)	(76)	(364)	430	(77)
Earnings (losses) on investments	—	49	—	(152)	—	(103)
Gains (losses) on sales of investments	(2)	1,094	—	—	—	1,092
Losses on purchases or exchanges of debt	(200)	—	—	—	—	(200)
Income (Loss) Before Income Taxes	$ (1,798)	$ 1,665	$ 112	$ (478)	$ (475)	$ (974)
Total Assets	$ 37,004	$ 2,291	$ 2,115	$ 2,529	$ (2,328)	$ 41,611
Capital Expenditures	$ 12,044	$ 852	$ 658	$ 554	$ —	$ 14,108

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)			
For the Year Ended December 31, 2011:						
Revenues	$ 6,024	$ 10,336	$ 1,258	$ —	$ (5,983)	$ 11,635
Intersegment revenues	—	(5,246)	(737)	—	5,983	—
Total revenues	$ 6,024	$ 5,090	$ 521	$ —	$ —	$ 11,635
Unrealized (gains) losses on natural gas, oil and NGL derivatives	789	—	—	—	—	789
Depreciation, depletion and amortization	1,759	55	172	37	(100)	1,923
(Gains) losses on sales of fixed assets	3	(441)	1	—	—	(437)
Impairments of fixed assets and other	—	43	3	—	—	46
Interest expense	(42)	(15)	(48)	(195)	256	(44)
Earnings on investments	—	95	—	61	—	156
Losses on purchases or exchanges of debt	(176)	—	—	—	—	(176)
Other income	260	1	5	35	(278)	23
Income (Loss) Before Income Taxes	$ 2,561	$ 745	$ 72	$ (168)	$ (330)	$ 2,880
Total Assets	$ 35,403	$ 4,047	$ 1,571	$ 2,718	$ (1,904)	$ 41,835
Capital Expenditures	$ 12,201	$ 1,219	$ 657	$ 484	$ —	$ 14,561

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)			
For the Year Ended December 31, 2010:						
Revenues	$ 5,647	$ 7,655	$ 757	$ —	$ (4,693)	$ 9,366
Intersegment revenues	—	(4,176)	(517)	—	4,693	—
Total revenues	$ 5,647	$ 3,479	$ 240	$ —	$ —	$ 9,366
Unrealized (gains) losses on natural gas, oil and NGL derivatives	658	—	—	—	—	658
Depreciation, depletion and amortization	1,518	43	94	28	(69)	1,614
(Gains) losses on sales of fixed assets	(1)	(139)	(1)	4	—	(137)
Impairments of fixed assets and other	(1)	20	—	—	2	21
Interest expense	(15)	(17)	(25)	(90)	128	(19)
Earnings on investments	—	193	—	34	—	227
Losses on purchases or exchanges of debt	(129)	—	—	—	—	(129)
Impairment of investments	—	—	—	(16)	—	(16)
Other income	134	2	—	8	(128)	16
Income (Loss) Before Income Taxes	$ 2,663	$ 584	$ 10	$ (102)	$ (271)	$ 2,884
Total Assets	$ 31,840	$ 3,436	$ 875	$ 2,044	$ (1,016)	$ 37,179
Capital Expenditures	$ 12,932	$ 624	$ 313	$ 163	$ —	$ 14,032

18. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company, owns no operating assets, and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes and contingent convertible senior notes listed in Note 3 are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly owned subsidiaries on a senior unsecured basis. Our oilfield services subsidiary, COS, and its subsidiaries are not guarantors of our senior notes, contingent convertible senior notes, term loan or corporate credit facility but are subject to the covenants and guarantees in the oilfield services revolving bank credit facility agreement referred to in Note 3 that limit their ability to pay dividends or distributions or make loans to Chesapeake. COS and its subsidiaries were released as guarantors of our senior notes, contingent convertible senior notes and corporate credit facility in October 2011 when they were formally reorganized and capitalized. Our midstream subsidiary, CMD, and certain of its subsidiaries were added as guarantors of our senior notes, contingent convertible senior notes, term loans and corporate credit facility in June 2012 upon the termination of the midstream credit facility. CMO and those subsidiaries were released as guarantors of our senior notes, contingent convertible senior notes, term loan and corporate credit facility in December 2012 upon the sale of CMO to ACMP. All prior year information has been restated to reflect COS, CMO and their subsidiaries as non-guarantor subsidiaries and CMD and certain of its subsidiaries as guarantor subsidiaries. Certain of our oilfield services subsidiaries, subsidiaries with noncontrolling interests, subsidiaries qualified as variable interest entities, and certain de minimis subsidiaries are also non-guarantors.

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of December 31, 2012, 2011 and 2010. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 228	$ 59	$ —	$ 287
Restricted cash	—	—	111	—	111
Other	1	2,369	513	(337)	2,546
Current assets held for sale	—	—	4	—	4
Total Current Assets	1	2,597	687	(337)	2,948
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net	—	29,063	3,077	(222)	31,918
Other property and equipment, net	—	3,066	1,549	—	4,615
Property and equipment held for sale, net	—	255	379	—	634
Total Property and Equipment, Net	—	32,384	5,005	(222)	37,167
LONG-TERM ASSETS:					
Other assets	217	1,396	261	(378)	1,496
Long-term assets held for sale	—	—	—	—	—
Investments in subsidiaries and intercompany advances	2,254	(185)	—	(2,069)	—
TOTAL ASSETS	$ 2,472	$ 36,192	$ 5,953	$ (3,006)	$ 41,611
CURRENT LIABILITIES:					
Current liabilities	$ 789	$ 5,368	$ 426	$ (338)	$ 6,245
Current liabilities held for sale	—	—	21	—	21
Intercompany payable to (receivable from) parent	(25,571)	24,372	1,330	(131)	—
Total Current Liabilities	(24,782)	29,740	1,777	(469)	6,266
LONG-TERM LIABILITIES:					
Long-term debt, net	11,089	—	1,068	—	12,157
Deferred income tax liabilities	361	2,415	127	(96)	2,807
Other liabilities	235	1,783	839	(372)	2,485
Total Long-Term Liabilities	11,685	4,198	2,034	(468)	17,449
EQUITY:					
Chesapeake stockholders' equity	15,569	2,254	2,142	(4,396)	15,569
Noncontrolling interests	—	—	—	2,327	2,327
Total Equity	15,569	2,254	2,142	(2,069)	17,896
TOTAL LIABILITIES AND EQUITY	$ 2,472	$ 36,192	$ 5,953	$ (3,006)	$ 41,611

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

	Parent[(a)]	Guarantor Subsidiaries[(a)]	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ 349	$ —	$ 351
Restricted cash	—	—	44	—	44
Other	1	2,647	344	(210)	2,782
Total Current Assets	1	2,649	737	(210)	3,177
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost, based on full cost accounting, net	—	29,284	2,017	(101)	31,200
Other property and equipment, net	—	2,828	2,732	—	5,560
Total Property and Equipment, Net	—	32,112	4,749	(101)	36,760
LONG-TERM ASSETS:					
Other assets	162	865	1,248	(377)	1,898
Investments in subsidiaries and intercompany advances	3,553	1,764	—	(5,317)	—
TOTAL ASSETS	$ 3,716	$ 37,390	$ 6,734	$ (6,005)	$ 41,835
CURRENT LIABILITIES:					
Current liabilities	$ 288	$ 6,431	$ 497	$ (134)	$ 7,082
Intercompany payable to (receivable from) parent	(21,850)	20,633	1,356	(139)	—
Total Current Liabilities	(21,562)	27,064	1,853	(273)	7,082
LONG-TERM LIABILITIES:					
Long-term debt, net	8,226	1,720	680	—	10,626
Deferred income tax liabilities	390	2,767	365	(38)	3,484
Other liabilities	38	2,286	735	(377)	2,682
Total Long-Term Liabilities	8,654	6,773	1,780	(415)	16,792
EQUITY:					
Chesapeake stockholders' equity	16,624	3,553	3,101	(6,654)	16,624
Noncontrolling interests	—	—	—	1,337	1,337
Total Equity	16,624	3,553	3,101	(5,317)	17,961
TOTAL LIABILITIES AND EQUITY	$ 3,716	$ 37,390	$ 6,734	$ (6,005)	$ 41,835

(a) We have revised the amounts presented as long-term debt in the Guarantor Subsidiaries and Parent columns to properly reflect the long-term debt issued by the Parent of $8.2 billion, which was incorrectly presented as long-term debt attributable to the Guarantor Subsidiaries as of December 31, 2011. The impact of this error was not material to our December 31, 2011 financial statements.

**CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
AS OF DECEMBER 31, 2012
($ in millions)**

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES					
Natural gas, oil and NGL	$ —	$ 5,858	$ 348	$ 72	$ 6,278
Marketing, gathering and compression	—	5,371	211	(151)	5,431
Oilfield services	—	—	1,940	(1,333)	607
Total Revenues	—	11,229	2,499	(1,412)	12,316
OPERATING EXPENSES					
Natural gas, oil and NGL production	—	1,280	24	—	1,304
Production taxes	—	182	6	—	188
Marketing, gathering and compression	—	5,285	114	(87)	5,312
Oilfield services	—	3	1,598	(1,136)	465
General and administrative	—	419	122	(6)	535
Natural gas, oil and NGL depreciation, depletion and amortization	—	2,361	146	—	2,507
Depreciation and amortization of other assets	—	176	272	(144)	304
Impairment of natural gas and oil properties	—	3,174	141	—	3,315
Net (gains) losses on sales of fixed assets	—	(269)	2	—	(267)
Impairments of fixed assets and other	—	275	65	—	340
Employee retirement and other termination benefits	—	5	2	—	7
Total Operating Expenses	—	12,891	2,492	(1,373)	14,010
INCOME (LOSS) FROM OPERATIONS	—	(1,662)	7	(39)	(1,694)
OTHER INCOME (EXPENSE)					
Interest expense	(858)	(50)	(84)	915	(77)
Earnings (losses) on investments	—	(167)	55	9	(103)
Gains on sales of investments	—	1,030	62	—	1,092
Losses on purchases or exchanges of debt	(200)	—	—	—	(200)
Other income (expense)	891	(116)	15	(782)	8
Equity in net earnings of subsidiary	(667)	(211)	—	878	—
Total Other Income (Expense)	(834)	486	48	1,020	720
INCOME (LOSS) BEFORE INCOME TAXES	(834)	(1,176)	55	981	(974)
INCOME TAX EXPENSE (BENEFIT)	(65)	(376)	21	40	(380)
NET INCOME (LOSS)	(769)	(800)	34	941	(594)
Net income attributable to noncontrolling interests	—	—	—	(175)	(175)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(769)	(800)	34	766	(769)
Other comprehensive income (loss)	6	(22)	—	—	(16)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ (763)	$ (822)	$ 34	$ 766	$ (785)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AS OF DECEMBER 31, 2011 ($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$ —	$ 5,886	$ 84	$ 54	$ 6,024
Marketing, gathering and compression	—	5,050	171	(131)	5,090
Oilfield services	—	—	1,260	(739)	521
Total Revenues	—	10,936	1,515	(816)	11,635
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	1,073	—	—	1,073
Production taxes	—	190	2	—	192
Marketing, gathering and compression	—	4,946	113	(92)	4,967
Oilfield services	—	1	976	(575)	402
General and administrative	—	477	71	—	548
Natural gas, oil and NGL depreciation, depletion and amortization	—	1,625	7	—	1,632
Depreciation and amortization of other assets	—	169	217	(95)	291
Net gains on sales of fixed assets	—	(2)	(435)	—	(437)
Impairments of fixed assets and other	—	—	46	—	46
Total Operating Expenses	—	8,479	997	(762)	8,714
INCOME (LOSS) FROM OPERATIONS	—	2,457	518	(54)	2,921
OTHER INCOME (EXPENSE):					
Interest expense	(640)	(12)	(50)	658	(44)
Earnings (losses) on investments	—	61	95	—	156
Losses on purchases or exchanges of debt	(176)	—	—	—	(176)
Other income	646	6	20	(649)	23
Equity in net earnings of subsidiary	1,845	276	—	(2,121)	—
Total Other Income (Expense)	1,675	331	65	(2,112)	(41)
INCOME (LOSS) BEFORE INCOME TAXES	1,675	2,788	583	(2,166)	2,880
INCOME TAX EXPENSE (BENEFIT)	(67)	980	227	(17)	1,123
NET INCOME (LOSS)	1,742	1,808	356	(2,149)	1,757
Net income attributable to noncontrolling interests	—	—	—	(15)	(15)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,742	1,808	356	(2,164)	1,742
Other comprehensive income (loss)	9	(7)	—	—	2
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 1,751	$ 1,801	$ 356	$ (2,164)	$ 1,744

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AS OF DECEMBER 31, 2010 ($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$ —	$ 5,603	$ —	$ 44	$ 5,647
Marketing, gathering and compression	—	3,475	104	(100)	3,479
Oilfield services	—	—	765	(525)	240
Total Revenues	—	9,078	869	(581)	9,366
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	893	—	—	893
Production taxes	—	157	—	—	157
Marketing, gathering and compression	—	3,356	41	(45)	3,352
Oilfield services	—	—	614	(406)	208
General and administrative	2	410	41	—	453
Natural gas, oil and NGL depreciation, depletion and amortization	—	1,394	—	—	1,394
Depreciation and amortization of other assets	—	161	130	(71)	220
Net gains on sales of fixed assets	—	—	(135)	(2)	(137)
Impairments of fixed assets and other	—	—	21	—	21
Total Operating Expenses	2	6,371	712	(524)	6,561
INCOME (LOSS) FROM OPERATIONS	(2)	2,707	157	(57)	2,805
OTHER INCOME (EXPENSE):					
Interest expense	(637)	(74)	(26)	718	(19)
Earnings (losses) on investments	—	34	193	—	227
Gains on sales of investments	—	—	—	—	—
Losses on purchases or exchanges of debt	(129)	—	—	—	(129)
Impairment of investments	—	(16)	—	—	(16)
Other income	718	11	5	(718)	16
Equity in net earnings of subsidiary	1,804	144	—	(1,948)	—
Total Other Income (Expense)	1,756	99	172	(1,948)	79
INCOME (LOSS) BEFORE INCOME TAXES	1,754	2,806	329	(2,005)	2,884
INCOME TAX EXPENSE (BENEFIT)	(20)	1,025	127	(22)	1,110
NET INCOME (LOSS)	1,774	1,781	202	(1,983)	1,774
Net income attributable to noncontrolling interests	—	—	—	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,774	1,781	202	(1,983)	1,774
Other comprehensive income (loss)	(14)	(256)	—	—	(270)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 1,760	$ 1,525	$ 202	$ (1,983)	$ 1,504

**CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2012
($ in millions)**

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 3,909	$ 305	$ (1,377)	$ 2,837
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(11,448)	(643)	—	(12,091)
Proceeds from divestitures of proved and unproved properties	—	5,583	301	—	5,884
Additions to other property and equipment	—	(855)	(1,796)	—	(2,651)
Other investing activities	—	4,581	2,133	(2,840)	3,874
Cash used in investing activities	—	(2,139)	(5)	(2,840)	(4,984)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	18,336	1,982	—	20,318
Payments on credit facilities borrowings	—	(20,056)	(1,594)	—	(21,650)
Proceeds from issuance of term loans, net of discount and offering costs	5,722	—	—	—	5,722
Proceeds from issuance of senior notes, net of discount and offering costs	1,263	—	—	—	1,263
Cash paid to purchase debt	(4,000)	—	—	—	(4,000)
Proceeds from sales of noncontrolling interests	—	—	1,077	—	1,077
Other financing activities	(417)	(328)	(4,119)	4,217	(647)
Intercompany advances, net	(2,568)	504	2,064	—	—
Cash provided by financing activities	—	(1,544)	(590)	4,217	2,083
Net increase (decrease) in cash and cash equivalents	—	226	(290)	—	(64)
Cash and cash equivalents, beginning of period	—	2	349	—	351
Cash and cash equivalents, end of period	$ —	$ 228	$ 59	$ —	$ 287

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 5,868	$ 438	$ (403)	$ 5,903
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(10,420)	(2,021)	—	(12,441)
Proceeds from divestitures of proved and unproved properties	—	7,651	—	—	7,651
Additions to other property and equipment	—	(520)	(1,489)	—	(2,009)
Other investing activities	—	(348)	719	616	987
Cash used in investing activities	—	(3,637)	(2,791)	616	(5,812)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	14,005	1,504	—	15,509
Payments on credit facilities borrowings	—	(15,898)	(1,568)	—	(17,466)
Proceeds from issuance of senior notes, net of discount and offering costs	977	—	637	—	1,614
Cash paid to purchase debt	(2,015)	—	—	—	(2,015)
Proceeds from sales of noncontrolling interests	—	—	1,348	—	1,348
Other financing activities	(494)	1,413	462	(213)	1,168
Intercompany advances, net	1,532	(1,750)	218	—	—
Cash provided by financing activities	—	(2,230)	2,601	(213)	158
Net increase (decrease) in cash and cash equivalents	—	1	248	—	249
Cash and cash equivalents, beginning of period	—	1	101	—	102
Cash and cash equivalents, end of period	$ —	$ 2	$ 349	$ —	$ 351

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 5,062	$ 325	$ (270)	$ 5,117
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(12,187)	—	—	(12,187)
Proceeds from divestitures of proved and unproved properties	—	4,292	—	—	4,292
Additions to other property and equipment	—	(502)	(824)	—	(1,326)
Other investing activities	—	(41)	627	132	718
Cash used in investing activities	—	(8,438)	(197)	132	(8,503)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	14,384	733	—	15,117
Payments on credit facilities borrowings	—	(12,664)	(639)	—	(13,303)
Proceeds from issuance of senior notes, net of discount and offering costs	1,967	—	—	—	1,967
Proceeds from issuance of preferred stock, net of offering costs	2,562	—	—	—	2,562
Cash paid to purchase debt	(3,434)	—	—	—	(3,434)
Proceeds from sales of noncontrolling interests	—	—	—	—	—
Other financing activities	(367)	641	(149)	147	272
Intercompany advances, net	(728)	723	14	(9)	—
Cash provided by financing activities	—	3,084	(41)	138	3,181
Net increase (decrease) in cash and cash equivalents	—	(292)	87	—	(205)
Cash and cash equivalents, beginning of period	—	293	14	—	307
Cash and cash equivalents, end of period	$ —	$ 1	$ 101	$ —	$ 102

19. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2012 and 2011 are as follows ($ in millions except per share data):

	Quarters Ended			
	March 31, 2012	June 30, 2012	September 30, 2012	December 31, 2012
Total revenues	$ 2,419	$ 3,389	$ 2,970	$ 3,538
Gross profit[a][b]	$ 6	$ 738	$ (3,194)	$ 756
Net income (loss) attributable to Chesapeake[b]	$ (28)	$ 972	$ (2,012)	$ 299
Net income (loss) available to common stockholders[b]	$ (71)	$ 929	$ (2,055)	$ 257
Net earnings (loss) per common share:				
Basic	$ (0.11)	$ 1.45	$ (3.19)	$ 0.39
Diluted	$ (0.11)	$ 1.29	$ (3.19)	$ 0.39

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

(a) Total revenue less operating costs.
(b) Includes a $3.315 billion ceiling test write-down on our natural gas and oil properties for the quarter ended September 30, 2012.

20. Recently Issued and Proposed Accounting Standards

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

In February 2013, the FASB issued guidance on disclosure of information about changes in accumulated other comprehensive income balances by component and significant items reclassified out of accumulated other comprehensive income. The new requirements include disclosing significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, if required to be reclassified to net income in their entirety. Other items are to be cross-referenced to other required disclosures that provide additional information about those amounts. The guidance is effective for interim and annual periods beginning after December 15, 2012. This guidance will not have an impact on our financial position or results of operations.

In December 2011, the FASB issued guidance on disclosure of information about offsetting and related arrangements to enable users of a company's financial statements to understand the effect of those arrangements on its financial position. In January 2013, the FASB issued additional guidance to clarify the scope of disclosures about offsetting and related arrangements, noting this guidance only applies to derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with specific criteria contained in other guidance or subject to a master netting arrangement or similar agreement. Both standards are effective for annual reporting periods beginning on or after January 1, 2013. This guidance will not have an impact on our financial position or results of operations.

21. Subsequent Events

In December 2012, Chesapeake announced that it had offered a voluntary separation program (VSP) to certain employees as part of the Company's ongoing efforts to improve efficiencies and reduce costs. The VSP was offered to approximately 275 employees who met criteria based upon a combination of age and years of Chesapeake service. Employees had until February 7, 2013 to respond to the offer. Prior to December 31, 2012, 14 employees accepted the offer and we recorded $2 million in charges related to their termination. Subsequent to December 31, 2012, 197 employees accepted the offer and we expect to record approximately $62 million of charges in 2013 related to their termination.

On January 23, 2013, Methanex Corporation and Chesapeake announced the execution of a 10-year agreement to supply all of the natural gas required for Methanex's one million tonne per year methanol plant in Geismar, Louisiana. Commencement of natural gas deliveries will coincide with the startup of the plant, which is expected by the end of 2014. The agreement is structured so that the natural gas price is linked to the methanol price; however, Chesapeake will never receive less than $4.00 per mmbtu for the natural gas it delivers to the plant regardless of methanol prices.

On January 29, 2013, we announced that Aubrey K. McClendon, our President, Chief Executive Officer (CEO) and a director, agreed to retire from the Company. Mr. McClendon will continue to serve as President, CEO and a director until the earlier of April 1, 2013 or the time at which his successor is appointed. Mr. McClendon's departure from the Company will be treated as a termination without cause under his employment agreement.

Also on January 29, 2013, the Compensation Committee of our Board of Directors approved retention awards for 14 of the Company's senior management team in the form of time-vested stock options to purchase an aggregate of 2.560 million shares of common stock. These awards, ranging from 150,000 to 360,000 stock options, have an exercise price equal to the closing price of the Company's common stock on the grant date, and vest one-third on each of the third, fourth and fifth anniversaries of the grant date. The options are subject to accelerated vesting if the executive is terminated (other than for cause) during the vesting period; however, no accelerated vesting will occur if the executive retires or voluntarily resigns prior to vesting.

On February 25, 2013 Chesapeake Energy Corporation and Sinopec International Petroleum Exploration and Production Corporation (Sinopec) announced the execution of an agreement which provides for Sinopec to purchase a 50% undivided interest in 850,000 of our net oil and natural gas leasehold acres in the Mississippi Lime play in northern Oklahoma (425,000 acres net to Sinopec). The total consideration for the transaction will be $1.02 billion in cash, of which approximately 93% will be received upon closing. Payment of the remaining proceeds will be subject to certain customary title contingencies. Production from these assets (including Mississippi Lime and other formations), net to our interest and prior to Sinopec's purchase, averaged approximately 34 thousand barrels of oil equivalent per day in the 2012 fourth quarter and, as of December 31, 2012, there was approximately 140 million barrels of oil equivalent of net proved reserves associated with the assets. All future exploration and development costs in the joint venture will be shared proportionately between the parties with no drilling carries involved. As the operator of the project, we will conduct all leasing, drilling, completion, operations and marketing activities for the joint venture. The transaction is anticipated to be completed in the 2013 second quarter.

Schedule II

CHESAPEAKE ENERGY CORPORATION
VALUATION AND QUALIFYING ACCOUNTS

Description	Balance Beginning of Period	Additions: Charged to Expense	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
		($ in millions)			
December 31, 2012:					
Allowance for doubtful accounts	$ 19	$ —	$ —	$ —	$ 19
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —
December 31, 2011:					
Allowance for doubtful accounts	$ 18	$ 1	$ —	$ —	$ 19
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —
December 31, 2010:					
Allowance for doubtful accounts	$ 24	$ —	$ —	$ (6)	$ 18
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —

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

Not applicable.

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

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. At the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2012.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the quarter ended December 31, 2012 which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management's annual report on internal control over financial reporting is included in Item 8 of this report.

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

Not applicable.

Part III

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

The names of executive officers and certain other senior officers of the company and their ages, titles and biographies as of the date hereof are incorporated by reference from Item 1 of this report. The other information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2013.

ITEM 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2013.

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

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2013.

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

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2013.

ITEM 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2013.

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules*

(a) The following financial statements, financial statement schedules and exhibits are filed as a part of this report:

1. *Financial Statements*. Chesapeake's consolidated financial statements are included in Item 8 of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules*. Schedule II is included in Item 8 of this report with our consolidated financial statements. No other financial statement schedules are applicable or required.
3. *Exhibits*. The following exhibits are filed herewith pursuant to the requirements of Item 601 of Regulation S-K:

		Incorporated by Reference					
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**	**Furnished Herewith**
2.1*	Purchase Agreement, dated June 7, 2012, by and among Chesapeake Midstream Holdings, L.L.C. and GIP II Eagle 1 Holding, L.P., GIP II Eagle 2 Holding, L.P. and GIP II Eagle 3 Holding, L.P.	8-K	001-13726	2.1	6/13/2012		
2.2*	Purchase Agreement, dated June 7, 2012, by and between Chesapeake Midstream Holdings, L.L.C. and GIP II Eagle 4 Holding, L.P.	8-K	001-13726	2.2	6/13/2012		
2.3*	Unit Purchase Agreement, dated December 11, 2012, between Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.L.C.	8-K	001-13726	2.1	12/17/2012		
3.1.1	Chesapeake's Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	8/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	8/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010		
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.2	6/8/2012		
4.1**	Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.5% Senior Notes due 2017.	8-K	001-13726	4.1	8/16/2005		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.2**	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% Senior Notes due 2020.	8-K	001-13726	4.12.1	11/15/2005		
4.3**	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.75% Contingent Convertible Senior Notes due 2035.	8-K	001-13726	4.12.2	11/15/2005		
4.4**	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.625% Senior Notes due 2013.	8-K	001-13726	4.1	6/30/2006		
4.5**	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/ BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% Senior Notes due 2017.	8-K	001-13726	4.1	12/6/2006		
4.6**	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.5% Contingent Convertible Senior Notes due 2037.	8-K	001-13726	4.1	5/15/2007		
4.7**	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.25% Senior Notes due 2018.	8-K	001-13726	4.1	5/29/2008		
4.8**	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.25% Contingent Convertible Senior Notes due 2038.	8-K	001-13726	4.2	5/29/2008		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.9.1**	Indenture dated as of February 2, 2009 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 9.5% Senior Notes due 2015.	8-K	001-13726	4.1	2/3/2009		
4.9.2	First Supplemental Indenture dated as of February 10, 2009 to Indenture dated as of February 2, 2009, with respect to additional 9.5% Senior Notes due 2015.	8-K	001-13726	4.2	2/17/2009		
4.10.1**	Indenture dated as of August 2, 2010 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee.	S-3	333-168509	4.1	8/3/2010		
4.10.2	First Supplemental Indenture dated as of August 17, 2010 to Indenture dated as of August 2, 2010 with respect to 6.875% Senior Notes due 2018.	8-A	001-13726	4.2	9/24/2010		
4.10.3	Second Supplemental Indenture, dated as of August 17, 2010 to Indenture dated as of August 2, 2010 with respect to 6.625% Senior Notes due 2020.	8-A	001-13726	4.3	9/24/2010		
4.10.4	Fifth Supplemental Indenture dated February 11, 2011 to Indenture dated as of August 2, 2010 with respect to 6.125% Senior Notes due 2021.	8-A	001-13726	4.2	2/22/2011		
4.10.5	Ninth Supplemental Indenture dated February 16, 2012 to Indenture dated as of August 2, 2010, with respect to 6.775% Senior Notes due 2019.	8-A	001-13726	4.2	2/24/2012		
4.11.1**	Eighth Amended and Restated Credit Agreement, dated as of December 2, 2010, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, The Royal Bank of Scotland plc and BNP Paribas, as Co-Syndication Agent, Credit Agricole Corporate and Investment Bank, as Documentation Agent, and the several lenders from time to time parties thereto.	8-K	001-13726	4.1	12/8/2010		
4.11.2	First Amendment to Eighth Amended and Restated Credit Agreement, dated as of September 19, 2011, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, the other agents named therein and the several lenders parties thereto.	10-Q	001-13726	4.12.1	11/9/2011		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.11.3	Second Amendment to Eighth Amended and Restated Credit Agreement, dated as of October 12, 2011, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, the other agents named therein and the several lenders parties thereto.	10-Q	001-13726	4.12.2	11/9/2011		
4.11.4	Third Amendment to Eighth Amended and Restated Credit Agreement, dated as of September 25, 2012, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, the other agents named therein and the several lenders parties thereto.	10-Q	001-13726	4.1	10/1/2012		
4.11.5	Fourth Amendment to Eighth Amended and Restated Credit Agreement, dated as of December 19, 2012, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Existing Borrower, Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P. as New Borrowers, Union Bank, N.A., as Administrative Agent, the other agents named therein and the several lenders parties thereto.					X	
4.12**	Credit Agreement, dated as of November 9, 2012, among Chesapeake Energy Corporation, as Borrower, Bank of America , as Administrative Agent, Goldman Sachs Bank USA and Jefferies Finance LLC, as Syndication Agent, and the several banks and other financial institution or entities from time to time parties thereto	8-K	001-13726	4.1	11/13/2012		
10.1.1†	Chesapeake's 2003 Stock Incentive Plan, as amended.	10-Q	001-13726	10.1.1	11/9/2009		
10.1.2†	Form of Amended 2012 Restricted Stock Award Agreement for Chesapeake's 2003 Stock Incentive Plan.					X	
10.1.3†	Form of 2013 Restricted Stock Award Agreement for Chesapeake's 2003 Stock Incentive Plan.					X	
10.2†	Chesapeake's 1992 Nonstatutory Stock Option Plan, as amended.	10-Q	001-13726	10.1.2	2/14/1997		
10.3†	Chesapeake's 1994 Stock Option Plan, as amended.	10-Q	001-13726	10.1.3	11/7/2006		
10.4†	Chesapeake's 1996 Stock Option Plan, as amended.	10-Q	001-13726	10.1.4	11/7/2006		
10.5†	Chesapeake's 1999 Stock Option Plan, as amended.	10-Q	001-13726	10.1.5	8/11/2008		
10.6†	Chesapeake's 2000 Employee Stock Option Plan, as amended.	10-Q	001-13726	10.1.6	8/11/2008		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.7†	Chesapeake's 2001 Stock Option Plan, as amended.	10-Q	001-13726	10.1.8	8/11/2008		
10.8†	Chesapeake's 2001 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.10	8/11/2008		
10.9†	Chesapeake's 2002 Stock Option Plan, as amended.	10-Q	001-13726	10.1.11	8/11/2008		
10.10†	Chesapeake's 2002 Non-Employee Director Stock Option Plan.	10-Q	001-13726	10.1.12	8/11/2008		
10.11†	Chesapeake's 2002 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.13	8/11/2008		
10.12	Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, as amended.	10-K	001-13726	10.1.14	2/29/2008		
10.13.1†	Chesapeake's Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1.14	6/8/2012		
10.13.2†	Form of Amended 2012 Restricted Stock Award Agreement for Amended and Restated Long Term Incentive Plan.					X	
10.13.3†	Form of 2013 Restricted Stock Award Agreement for Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.3	2/4/2013		
10.13.4†	Form of Nonqualified Stock Option Agreement for Amended and Restated Long Term Incentive Plan	8-K	001-13726	10.1	2/4/2013		
10.13.5†	Form of Retention Nonqualified Stock Option Agreement for Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.2	2/4/2013		
10.13.6†	Form of Amended 2012 Non-Employee Director Restricted Stock Award Agreement for Amended and Restated Long Term Incentive Plan.					X	
10.13.7†	Form of 2013 Non-Employee Director Restricted Stock Award Agreement for Amended and Restated Long Term Incentive Plan.					X	
10.13.8†	Form of 2012 Performance Share Unit Award Agreement for Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1.17	12/21/2011		
10.13.9†	Form of 2013 Performance Share Unit Award Agreement for Amended and Restated Long Term Incentive Plan.					X	
10.14†	Restated Founder Well Participation Program.	8-K	001-13726	1.2	5/2/2012		
10.15†	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan.	10-K	001-13726	10.1.13	3/1/2011		
10.16†	Chesapeake Energy Corporation Deferred Compensation Plan for Non-Employee Directors.					X	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.17†	Third Amended and Restated Employment Agreement dated as of March 1, 2009 between Aubrey K. McClendon and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.1	5/11/2009		
10.18†	Employment Agreement dated as of January 1, 2013 between Steven C. Dixon and Chesapeake Energy Corporation.					X	
10.19†	Employment Agreement dated as of January 1, 2013 between Domenic J. Dell'Osso, Jr. and Chesapeake Energy Corporation.					X	
10.20†	Employment Agreement dated as of January 1, 2013 between Douglas J. Jacobson and Chesapeake Energy Corporation.					X	
10.21†	Employment Agreement dated as of January 1, 2013 between Jeffrey A. Fisher and Chesapeake Energy Corporation.					X	
10.22†	Form of Employment Agreement dated as of January 1, 2013 between Executive Vice President/ Senior Vice President and Chesapeake Energy Corporation.	8-K	001-13726	10.1	1/7/2013		
10.23	Letter Agreement, dated as of April 30, 2012, between the Board of Directors and Aubrey K. McClendon.	8-K	001-13726	1.1	5/2/2012		
10.24†	Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries.	8-K	001-13726	10.3	6/27/2012		
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X	
21	Subsidiaries of Chesapeake.					X	
23.1	Consent of PricewaterhouseCoopers LLP.					X	
23.2	Consent of Netherland, Sewell & Associates, Inc.					X	
23.3	Consent of PetroTechnical Services, Division of Schlumberger Technology Corporation.					X	
23.4	Consent of Ryder Scott Company, L.P.					X	
31.1	Aubrey K. McClendon, President and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Domenic J. Dell’Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Aubrey K. McClendon, President and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	SEC File Number	Exhibit	Filing Date		
32.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
99.1	Report of Netherland, Sewell & Associates, Inc.					X	
99.2	Report of PetroTechnical Services, Division of Schlumberger Technology Corporation.					X	
99.3	Report of Ryder Scott Company, L.P.					X	
101.INS#	XBRL Instance Document.					X	
101.SCH#	XBRL Taxonomy Extension Schema Document.					X	
101.CAL#	XBRL Taxonomy Extension Calculation Linkbase Document.					X	
101.DEF#	XBRL Taxonomy Extension Definition Linkbase Document.					X	
101.LAB#	XBRL Taxonomy Extension Labels Linkbase Document.					X	
101.PRE#	XBRL Taxonomy Extension Presentation Linkbase Document.					X	

* Schedules and exhibits omitted pursuant to Item 601(b)(2) of Regulation S-K. The Company agrees to furnish supplementally a copy of any omitted schedule or exhibit to the Securities and Exchange Commission upon request, subject to the Company's right to request confidential treatment of any requested exhibit or schedule.

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

† Management contract or compensatory plan or arrangement.

Signatures

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

CHESAPEAKE ENERGY CORPORATION

Date: March 1, 2013

By: /S/ AUBREY K. MCCLENDON

Aubrey K. McClendon
President and Chief Executive Officer

POWER OF ATTORNEY

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

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

Signature	Capacity	Date
/s/ AUBREY K. MCCLENDON **Aubrey K. McClendon**	President and Chief Executive Officer (Principal Executive Officer)	March 1, 2013
/s/ DOMENIC J. DELL'OSSO, JR. **Domenic J. Dell'Osso, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2013
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President - Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 1, 2013
/s/ ARCHIE W. DUNHAM **Archie W. Dunham**	Chairman of the Board	March 1, 2013
/s/ BOB G. ALEXANDER **Bob G. Alexander**	Director	March 1, 2013
/s/ V. BURNS HARGIS **V. Burns Hargis**	Director	March 1, 2013
/s/ VINCENT J. INTRIERI **Vincent J. Intrieri**	Director	March 1, 2013
/s/ R. BRAD MARTIN **R. Brad Martin**	Director	March 1, 2013
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	March 1, 2013
/s/ FREDRIC M. POSES **Fredric M. Poses**	Director	March 1, 2013
/s/ LOUIS A. SIMPSON **Louis A. Simpson**	Director	March 1, 2013

CORPORATE INFORMATION

CORPORATE HEADQUARTERS

6100 North Western Avenue
Oklahoma City, OK 73118
(405) 848-8000

INVESTOR INFORMATION

Company financial information, public disclosures and other information are available through Chesapeake's website at www.chk.com. We will promptly deliver free of charge, upon request, a copy of the annual report on Form 10-K to any shareholder requesting a copy. Requests should be directed to Investor Relations at our corporate headquarters address.

COMMON STOCK

Chesapeake Energy Corporation's common stock is listed on the New York Stock Exchange (NYSE) under the symbol CHK. As of March 31, 2013 there were approximately 355,000 beneficial owners of our common stock.

COMMON STOCK DIVIDENDS

During 2012, the company declared a cash dividend of $0.0875 per share on March 5, June 12, September 24 and December 17 for a total dividend declared of $0.35 per share.

INDEPENDENT PUBLIC ACCOUNTANTS

PricewaterhouseCoopers LLP
6120 South Yale, Suite 1850
Tulsa, OK 74136
(918) 524-1200

STOCK TRANSFER AGENT AND REGISTRAR

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to our transfer agent:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021
(800) 884-4225
www.computershare.com

TRUSTEE FOR THE COMPANY'S SENIOR NOTES

Issued prior to 2013
The Bank of New York
Mellon Trust Company, N.A.
101 Barclay Street, 8th Floor
New York, NY 10286
www.bnymellon.com

Issued in 2013
Deutsche Bank Trust Company Americas
60 Wall Street, 37th Floor
New York, NY 10005
www.tss.db.com

FORWARD-LOOKING STATEMENTS

The letter to shareholders includes "forward-looking statements" that give our current expectations or forecasts of future events. They include our planned drilling activity and capital expenditures, resulting expected production, natural gas price trends and future asset sales, as well as statements concerning anticipated cash flow and liquidity, our business strategy and objectives for future operations. 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 our 2012 Annual Report on Form 10-K included in this report. We caution you not to place undue reliance on forward-looking statements, 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 filings with the Securities and Exchange Commission regarding the risks and factors that may affect our business.

CHESAPEAKE COMMON STOCK PRICE HISTORY

2013	High	Low	Last
First Quarter	$ 22.97	$ 16.32	$ 20.41

2012	High	Low	Last
Fourth Quarter	$ 21.66	$ 16.23	$ 16.62
Third Quarter	20.64	16.62	18.87
Second Quarter	23.69	13.32	18.60
First Quarter	26.09	20.41	23.17

2011	High	Low	Last
Fourth Quarter	$ 29.87	$ 22.00	$ 22.29
Third Quarter	35.75	25.54	25.55
Second Quarter	34.70	27.28	29.69
First Quarter	35.95	25.93	33.52

2010	High	Low	Last
Fourth Quarter	$ 26.43	$ 20.97	$ 25.91
Third Quarter	23.00	19.68	22.65
Second Quarter	25.55	19.62	20.95
First Quarter	29.22	22.10	23.64

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