Chesapeake ENERGY

Leading a Responsible Energy Future

2013 ANNUAL REPORT

At Chesapeake we are focused on delivering shareholder value through financial discipline and profitable and efficient growth from captured resources, including balancing capital expenditures with cash flow from operations, reducing operational risk and complexity, promoting a culture of safety and integrity, and being a great business.

LEADING A RESPONSIBLE ENERGY FUTURE™

Dear Fellow Shareholders

2013 was an exciting year of growth and transition for Chesapeake Energy.

We completed a major transformational initiative designed to drive greater value for our shareholders through profitable and sustainable growth. Chesapeake has an industry-leading portfolio of high-quality unconventional assets, and we are taking the necessary measures required to drive business results that reflect our asset quality. I am very proud of our team as we rapidly achieved significant improvements in financial and operational performance through our focus on value creation. Chesapeake is positioned for further competitive and profitable growth, and we will relentlessly pursue our goal of becoming a top-performing E&P company.

We completed an organizational restructuring with a clear vision to align strategy and business priorities. In addition, we developed specific action plans to improve our capital efficiency, investment returns and cash flow growth. We conducted a critical evaluation of our assets and investment portfolio to determine how to further reduce our leverage and the complexity in our financial statements.

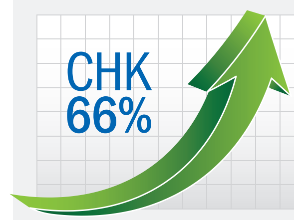
We implemented a new value-driven strategy based on two fundamental tenets: (1) financial discipline; and (2) profitable and efficient growth from captured resources. Consistent with our strategy, we demonstrated significant progress in our investment quality, capital efficiency and cash cost management in 2013. For the first time in the company's history, we established the essential linkage between corporate strategy, top-quartile performance metrics, performance management and employee compensation. We are ensuring the best investment opportunities are funded in our capital budget by relying upon value-based, competitive investment criteria. Integrated development strategies and business plans in our newly formed business units complement our focus on value creation and continuous improvement, and drive accountability through the organization.

Importantly, we launched a new company-wide core value system to guide our decisions and business practices. Our core values are the fabric that binds our employees together with a commitment to each other, our shareholders and other stakeholders as well as the environment. We will conduct our business in the spirit of and with a focus on servant leadership, compliance and value creation. Our core values also serve as a guide by which we measure each other, and by which our stakeholders can measure the company and our success.

Our total shareholder return and operating performance were outstanding in 2013. Rising 66%, our total shareholder return experienced top-quartile appreciation in 2013. Adjusting for divestitures, we recognized production growth of 11% in 2013, producing a Chesapeake record of 244 million barrels of oil equivalent. We continued our focus on liquids growth, generating a five-year compounded annual growth rate of nearly 40%. We reduced 2013 combined production and general and administrative costs by $225 million compared to 2012. We reduced capital expenditures by 50% compared to 2012, and we achieved significant improvements in capital efficiency and investment cycle times. In addition, we reduced our total leverage and obligations as well as financial complexity.

In 2014 we plan to further improve our capital efficiency, our financial leverage and our ability to grow cash flow. We remain focused on execution, using the unique skill set of our Chesapeake team members. We also remain firmly committed to environmental and safety excellence in our operations and regulatory compliance.

Thank you for your investment in Chesapeake Energy. The powerful combination of our high-quality assets, motivated and talented employees, and a value-driven strategy provides a compelling growth opportunity to our investors. We are at the very beginning of the value capture era in our history. **It is an exciting time at Chesapeake!**



DELIVERING TOP TOTAL SHAREHOLDER RETURN

Chesapeake finished 2013 with total shareholder return of 66%, which propelled the company to the second-highest performance among its 11-company peer group.

Robert Douglas Lawler
President, Chief Executive Officer
and Director
April 30, 2014

Financial Review

FINANCIAL AND OPERATIONAL HIGHLIGHTS

ADJUSTED AVERAGE DAILY PRODUCTION UP 11% YEAR OVER YEAR WITH 50% LESS CAPITAL EMPLOYED

OIL PRODUCTION UP 32% YEAR OVER YEAR

ADJUSTED EBITDA INCREASED YEAR OVER YEAR TO $5.016 BILLION [(a)(b)]

FINANCIAL AND OPERATING DATA

($ in millions, except per share data)

Years Ended December 31	2013	2012	2011	2010	2009
Revenues:					
Natural gas, oil and NGL	$ 7,052	$ 6,278	$ 6,024	$ 5,647	$ 5,049
Marketing, gathering and compression	9,559	5,431	5,090	3,479	2,463
Oilfield services	895	607	521	240	190
Total revenues	$ 17,506	$ 12,316	$ 11,635	$ 9,366	$ 7,702
Total operating expenses	$ 15,437	$ 14,010	$ 8,714	$ 6,561	$ 16,647
Total other income (expense)	$ (627)	$ 720	$ (41)	$ 79	$ (343)
Income (loss) before income taxes	$ 1,442	$ (974)	$ 2,880	$ 2,884	$ (9,288)
Income tax expense (benefit)	$ 548	$ (380)	$ 1,123	$ 1,110	$ (3,483)
Net income (loss) attributable to Chesapeake	$ 724	$ (769)	$ 1,742	$ 1,774	$ (5,830)
Net income (loss) available to common stockholders	$ 474	$ (940)	$ 1,570	$ 1,663	$ (5,853)
EPS – diluted	$ 0.73	$ (1.46)	$ 2.32	$ 2.51	$ (9.57)
Operating cash flow (non-GAAP)[(a)(c)]	$ 4,956	$ 3,920	$ 4,487	$ 5,168	$ 4,487
OTHER OPERATING AND FINANCIAL DATA					
Proved reserves in oil equivalents (mmboe)	2,678	2,615	3,132	2,849	2,376
Future net natural gas and oil revenues discounted at 10% (PV-10)[(d)]	$ 21,676	$ 17,773	$ 19,878	$ 15,146	$ 9,449
Production (mmboe)	244	237	199	173	151
Stock price (at end of period)	$ 27.14	$ 16.62	$ 22.29	$ 25.91	$ 25.88

(a) A non-GAAP financial measure. 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) EBITDA represents net income (loss) before income tax expense, interest expense and depreciation, depletion and amortization expense. Adjusted EBITDA excludes unrealized gains and losses on natural gas, oil and NGL derivatives, restructuring and other termination costs, impairments, gains and losses on sales of fixed assets and investments, losses on investments, losses on purchases of debt and extinguishment of other financing, and net income attributable to noncontrolling interests.

(c) Operating cash flow represents cash provided by (used in) operating activities before changes in assets and liabilities.

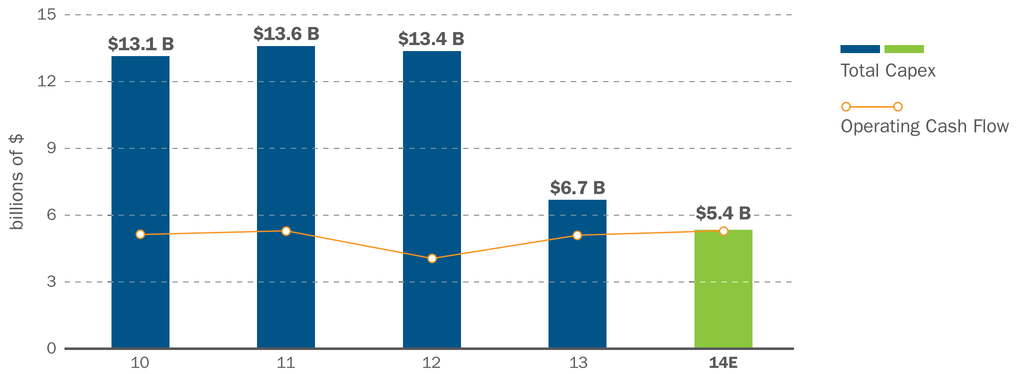
(d) PV-10 is the present value (10% discount rate) of estimated future gross revenues to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs calculated in accordance with SEC regulations in effect at the respective year ends. Please see pages 157 – 158 of our Form 10-K for information on the standardized measure of discounted future net revenues.

REDUCTION IN TOTAL CAPITAL EXPENDITURES YEAR OVER YEAR

COMBINED PRODUCTION AND G&A EXPENSE SAVINGS

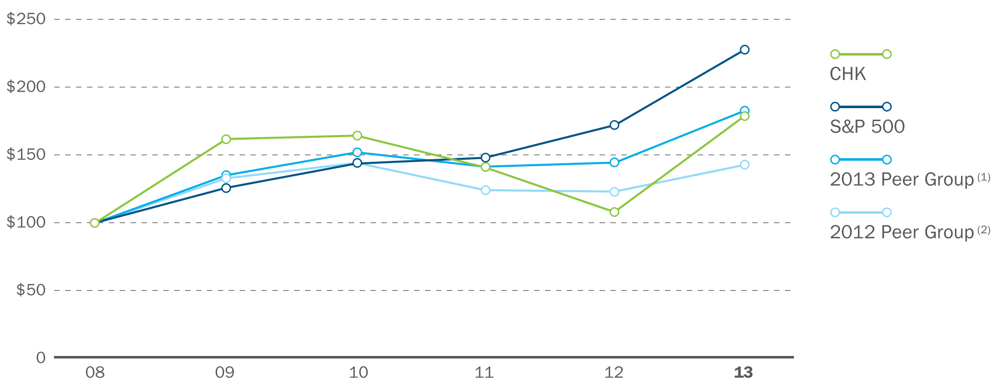
2013 YEAR-END PROVED RESERVES

TOTAL CAPEX AND OPERATING CASH FLOW



CHESAPEAKE'S FIVE-YEAR COMMON STOCK PERFORMANCE

The graph assumes an investment of $100 on December 31, 2008 and the reinvestment of all dividends.



(1) The 2013 peer group is comprised of Anadarko Petroleum Corporation, Apache Corporation, Continental Resources, Inc., Devon Energy Corporation, Encana Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Noble Energy, Inc., Pioneer Natural Resources and Southwestern Energy.

(2) The 2012 peer group is comprised of Anadarko Petroleum Corporation, Apache Corporation, Devon Energy Corporation, Encana Corporation and EOG Resources, Inc. The change in peer group was expanded from five companies in 2012 in order to more accurately show the returns of companies that are similar to Chesapeake in size, scope and nature of business obligations.

CORE VALUES

At Chesapeake our core values serve as the foundation for all of our activities and provide the lens through which we evaluate every decision we make. We believe that by living our core values we are building a stronger, more prosperous Chesapeake for all of our stakeholders. Our core values are:

Integrity and trust

- Be truthful and ethical
- Acknowledge errors and hold ourselves accountable
- Do what we say we will do

Respect

- Value the opinions of our stakeholders
- Promote diversity of thoughts and ideas
- Protect our employees, stakeholders and the environment

Transparency and open communication

- Be clear in our business strategies
- Share best practices

Commercial focus

- Be investment advisors
- Be stewards of corporate resources and the environment
- Take prudent risks, employing innovative ideas and technology

Change leadership

- Elevate innovative solutions
- Pursue continuous development and improvement
- Seek to deliver more than what is expected

BOARD OF DIRECTORS

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

Bob G. Alexander [(2)]
Former President and
Chief Executive Officer
National Energy Group, Inc.
Edmond, Oklahoma

Will retire from the Board at the 2014 annual meeting of shareholders

Vincent J. Intrieri [(1,3)]
Senior Managing Director
Icahn Capital LP
New York, New York

Robert D. "Doug" Lawler
President and
Chief Executive Officer
Chesapeake Energy Corporation
Oklahoma City, Oklahoma

R. Brad Martin [(1,2)]
Chairman
RBM Venture Company
Former Chairman and
Chief Executive Officer
Saks Incorporated
Memphis, Tennessee

Merrill A. "Pete" Miller, Jr. [(2)]
Executive Chairman
National Oilwell Varco, Inc.
Houston, Texas

Frederic M. Poses [(1)]
Chief Executive Officer
Ascend Performance Materials
New York, New York

Louis A. Raspino [(3)]
Former President and
Chief Executive Officer
Pride International, Inc.
Houston, Texas

Thomas L. Ryan [(3)]
President and
Chief Executive Officer
Service Corporation International
Houston, Texas

(1) Nominating, Governance and Social Responsibility Committee
(2) Compensation Committee
(3) Audit Committee

MANAGEMENT TEAM

Robert D. "Doug" Lawler
President, Chief Executive Officer and Director

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

Douglas J. Jacobson
Executive Vice President – Acquisitions & Divestitures

James R. Webb
Executive Vice President – General Counsel and Corporate Secretary

M. Chris Doyle
Senior Vice President – Operations, Northern Division

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 – Exploration & Subsurface Technology

Mikell J. "Jason" Pigott
Senior Vice President – Operations, Southern Division

John K. Reinhart
Senior Vice President – Operations & Technical Services

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

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

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, 2013

[ ] 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
9.5% Senior Notes due 2015	New York Stock Exchange
3.25% Senior Notes due 2016	New York Stock Exchange
6.25% Senior Notes due 2017	New York Stock Exchange
6.5% Senior Notes due 2017	New York Stock Exchange
6.875% Senior Notes due 2018	New York Stock Exchange
7.25% Senior Notes due 2018	New York Stock Exchange
6.625% Senior Notes due 2020	New York Stock Exchange
6.875% Senior Notes due 2020	New York Stock Exchange
6.125% Senior Notes due 2021	New York Stock Exchange
5.375% Senior Notes due 2021	New York Stock Exchange
5.75% Senior Notes due 2023	New York Stock Exchange
2.75% Contingent Convertible Senior Notes due 2035	New York Stock Exchange
2.5% Contingent Convertible Senior Notes due 2037	New York Stock Exchange
2.25% Contingent Convertible Senior Notes due 2038	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	New York Stock Exchange

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

None

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

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

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

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

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

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

Large Accelerated Filer [X] Accelerated Filer [ ] Non-accelerated Filer [ ] Smaller Reporting Company [ ]

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2013 was approximately $13.6 billion. At February 11, 2014, there were 666,212,515 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2014 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
2013 ANNUAL REPORT ON FORM 10-K
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PART I

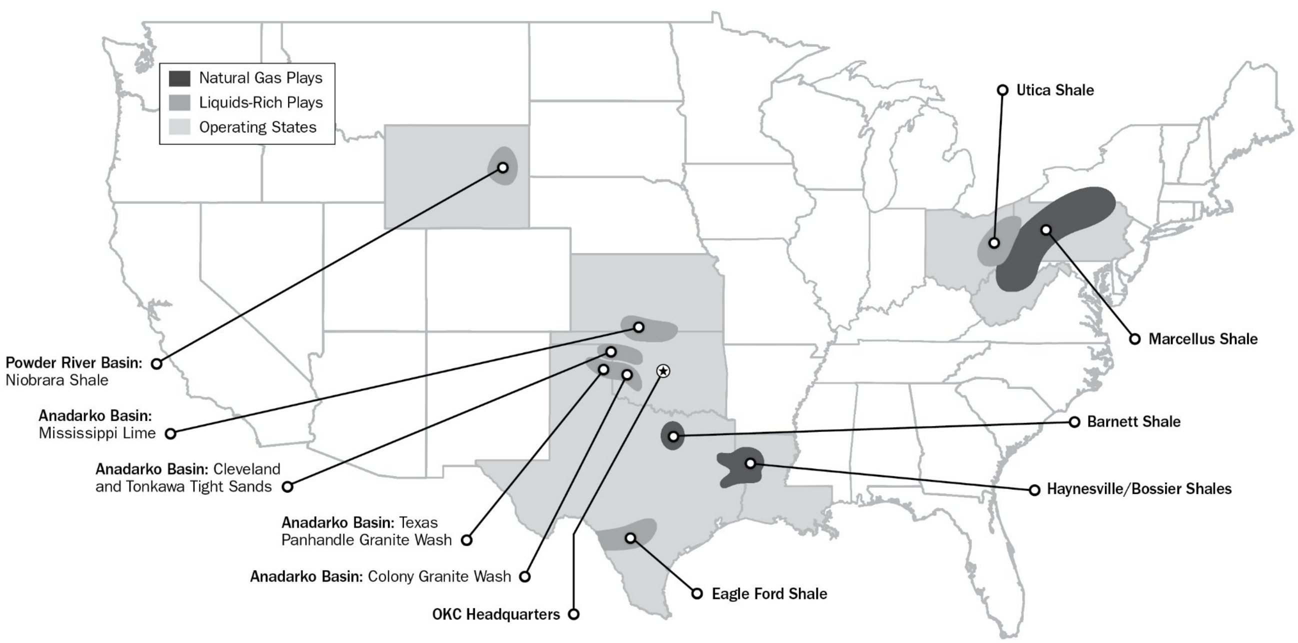
Item 1. *Business*

Unless the context otherwise requires, references to “Chesapeake”, the “Company”, “us”, “we” and “our” in this report are to Chesapeake Energy Corporation together with its subsidiaries. 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. Definitions of natural gas and oil industry terms appearing in this report can be found under *Glossary of Natural Gas and Oil Terms* beginning on page 20. Please note that we have changed the oil and natural gas equivalent reporting convention from that used in our previous reports to oil equivalent. Combined natural gas, oil and NGL volume amounts are shown in barrels of oil equivalent (boe) rather than in thousand cubic feet of natural gas equivalent (mcfe). Oil equivalent is based on six thousand cubic feet of natural gas to one barrel of oil or NGL.

Our Business

The Company is currently the second-largest producer of natural gas and the tenth-largest producer of liquids in the U.S. We own interests in approximately 46,800 natural gas and oil wells that produced an average of approximately 665 mboe per day in the 2013 fourth quarter, net to our interest. We have a large and geographically diverse resource base of onshore U.S. unconventional natural gas and liquids assets. We have 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/ Hogshooter, 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. 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. We also 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 estimated proved reserves as of December 31, 2013 were 2.678 bboe, an increase of 63 mmboe, or 2%, from 2.615 bboe at year-end 2012. The 2013 proved reserve movement included 524 mmboe of extensions and discoveries, 162 mmboe of upward revisions resulting from higher natural gas and oil prices and 192 mmboe of downward revisions resulting from changes to previous estimates as further discussed below in *Natural Gas, Oil and NGL Reserves* and in *Supplemental Disclosures About Natural Gas, Oil and NGL Producing Activities* included in Item 8 of this report. In 2013, we produced 244 mmboe, acquired 2 mmboe and divested 189 mmboe of estimated proved reserves. Natural gas and oil prices used in estimating proved reserves as of December 31, 2013 increased from prices as of December 31, 2012 using the trailing 12-month average prices required by the Securities and Exchange

Commission (SEC). Natural gas prices increased $0.91, or 33%, to $3.67 per mcf from $2.76 per mcf, and oil prices increased by $1.98, or 2%, to $96.82 per bbl from $94.84 per bbl. Proved developed reserves made up 68% of our proved reserves as of December 31, 2013 compared to 57% as of December 31, 2012.

Our daily production for 2013 averaged 670 mboe, an increase of 22 mboe, or 3%, over the 648 mboe of daily production for 2012, and consisted of approximately 2.999 bcf of natural gas (75% on an oil equivalent basis), approximately 112,600 bbls of oil (17% on an oil equivalent basis) and approximately 57,200 bbls of NGL (8% on an oil equivalent basis). Our natural gas production in 2013 decreased 3%, or approximately 85 mmcf per day; our oil production increased 32%, or approximately 27,200 bbls per day; and our NGL production increased 19%, or approximately 9,100 bbls per day.

Information About Us

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.

Business Strategy

With substantial leasehold positions in most of the premier U.S. onshore resource plays, Chesapeake is focused on finding and producing hydrocarbons in a responsible and efficient manner that seeks to maximize shareholder returns. We are committed to increasing our profitability and decreasing our corporate and balance sheet complexity through the execution of our business strategy, which consists of two fundamental tenets: financial discipline and profitable and efficient growth from captured resources.

We are applying financial discipline to all aspects of our business, with the primary goals of approximating capital expenditures with cash flow from operations, divesting noncore assets and affiliates, achieving investment grade metrics, lowering our per unit cost structure, and reducing financial and operational risk and complexity. As a result of our focus on financial discipline, average per unit production expenses during 2013 decreased 14% from 2012, while general and administrative expenses (excluding stock-based compensation and restructuring and other termination costs) decreased 17%. We anticipate further decreases in our per unit expenses during 2014 as we continue to exercise cost discipline.

The Company's substantial inventory of hydrocarbon resources provides a strong foundation for future growth. We believe that focusing on profitable and efficient growth from our captured resources will allow us to deliver attractive financial returns through all phases of the commodity price cycle. We have seen and continue to see increased efficiencies through our leveraging of first-well investments made in prior periods, including drilling on pre-existing pads. We have also implemented a competitive capital allocation process designed to optimize our asset portfolio and identify the highest quality projects for future investment. To better understand our opportunities for continuous improvement, we benchmark our performance against that of our peers and evaluate the performance of completed projects. We also pay careful attention to safety, regulatory compliance and environmental stewardship measures while executing our growth strategy.

In the 2013 second half, we conducted a company-wide review of our operations, assets and organizational structure to best position the Company to maximize shareholder value going forward as we execute our strategic priorities. We reorganized the Company into Northern and Southern operating divisions as well as an Exploration and Subsurface Technology unit and Operations and Technical Services unit that are supported by enterprise-wide service departments. The new organizational structure is designed to increase accountability and communication throughout the Company, while encouraging standardization, efficiency and continuous improvement. As part of the reorganization, we reduced our workforce by approximately 1,000 employees, including approximately 900 employees under a workforce reduction plan we implemented in September and October 2013. We anticipate the workforce reduction will result in future cost savings and help the Company demonstrate more profitable and efficient growth. See Note 17 of the notes to our consolidated financial statements included in Item 8 of this report and *Results of Operations - Restructuring and Other Termination Costs* in Item 7 of this report for further discussion of our workforce reductions. While furthering our strategic priorities, certain actions that would reduce financial leverage and complexity could negatively impact our future results of operations and/or liquidity. We expect to incur various cash and noncash charges, including but not limited to impairments of fixed assets, lease termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity.

We are continuing to review and refine our portfolio for assets that fit best with the Company's strategy of profitable growth from captured resources. On February, 24, 2014, we announced that we are pursuing strategic alternatives for our oilfield services business, including a potential spin-off to Chesapeake shareholders or an outright sale. We believe that our oilfield services business can maximize its value to Chesapeake shareholders outside of the current ownership structure. See *Oilfield Services* below for a further description of our oilfield services business.

Operating Divisions

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

Southern Division. Includes the Eagle Ford Shale in South Texas, the Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas, the Haynesville/Bossier Shale in northwestern Louisiana and East Texas and the Barnett Shale in the Fort Worth Basin in north-central Texas.

Northern Division. Includes the Utica Shale in Ohio, West Virginia and Pennsylvania, the Marcellus Shale in the northern Appalachian Basin in West Virginia and Pennsylvania and the Niobrara Shale in the Powder River Basin in Wyoming.

Well Data

At December 31, 2013, we had interests in approximately 46,800 gross (20,900 net) productive wells, including properties in which we held an overriding royalty interest. Of these wells, 38,100 gross (18,400 net) were classified as natural gas productive wells and 8,700 gross (2,500 net) were classified as oil productive wells. Chesapeake operates approximately 28,100 of its 46,800 productive wells. During 2013, we completed 1,376 gross (899 net) wells and participated in another 564 gross (86 net) wells completed by other operators. We operate approximately 90% 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.

	2013				2012				2011			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	1,704	99	847	99	2,075	99	956	99	2,536	99	1,077	99
Dry	21	1	9	1	21	1	5	1	10	1	3	1
Total	1,725	100	856	100	2,096	100	961	100	2,546	100	1,080	100
Exploratory:												
Productive	209	97	124	96	495	98	305	98	430	99	201	99
Dry	6	3	5	4	10	2	6	2	3	1	1	1
Total	215	100	129	100	505	100	311	100	433	100	202	100

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

	2013		2012		2011	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Southern	1,352	698	1,933	982	2,691	1,166
Northern	588	287	668	290	288	116
Total	1,940	985	2,601	1,272	2,979	1,282

At December 31, 2013, we had 878 (335 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,		
	2013	2012	2011
Net Production:			
Natural gas (bcf)	1,095	1,129	1,004
Oil (mmbbl)	41	31	17
NGL (mmbbl)	21	18	15
Oil equivalent (mmboe)[a]	244	237	199
Natural Gas, Oil and NGL Sales ($ in millions):			
Natural gas sales	$ 2,430	$ 2,004	$ 3,133
Natural gas derivatives - realized gains (losses)	9	328	1,656
Natural gas derivatives - unrealized gains (losses)	(52)	(331)	(669)
Total natural gas sales	2,387	2,001	4,120
Oil sales	3,911	2,829	1,523
Oil derivatives - realized gains (losses)	(108)	39	(60)
Oil derivatives - unrealized gains (losses)	280	857	(128)
Total oil sales	4,083	3,725	1,335
NGL sales	582	526	603
NGL derivatives - realized gains (losses)	—	(9)	(42)
NGL derivatives - unrealized gains (losses)	—	35	8
Total NGL sales	582	552	569
Total natural gas, oil and NGL sales	$ 7,052	$ 6,278	$ 6,024
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 2.22	$ 1.77	$ 3.12
Oil ($ per bbl)	$ 95.17	$ 90.49	$ 89.80
NGL ($ per bbl)	$ 27.87	$ 29.89	$ 40.96
Oil equivalent ($ per boe)	$ 28.33	$ 22.61	$ 26.42
Average Sales Price (including realized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 2.23	$ 2.07	$ 4.77
Oil ($ per bbl)	$ 92.53	$ 91.74	$ 86.25
NGL ($ per bbl)	$ 27.87	$ 29.37	$ 38.12
Oil equivalent ($ per boe)	$ 27.92	$ 24.12	$ 34.23
Other Operating Income[b] ($ in millions):			
Marketing, gathering and compression net margin	$ 98	$ 119	$ 123
Oilfield services net margin	$ 159	$ 142	$ 119
Expenses ($ per boe):			
Natural gas, oil and NGL production	$ 4.74	$ 5.50	$ 5.39
Production taxes	$ 0.94	$ 0.79	$ 0.96
General and administrative expenses[c]	$ 1.86	$ 2.26	$ 2.75
Natural gas, oil and NGL depreciation, depletion and amortization	$ 10.59	$ 10.58	$ 8.20
Depreciation and amortization of other assets	$ 1.28	$ 1.28	$ 1.46
Interest expense[d]	$ 0.65	$ 0.35	$ 0.18

(a) Oil 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. In recent years, the price for a bbl of oil and NGL has been significantly higher than the price for six mcf of natural gas.

(b) Includes revenue and operating costs and excludes depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See *Depreciation and Amortization of Other Assets, Impairments of Fixed Assets and Other* and *Net (Gains) Losses on Sales of Fixed Assets* under *Results of Operations* in Item 7 for details of the depreciation and amortization and impairments of assets and net gains or losses on sales of fixed assets associated with our marketing, gathering and compression and oilfield services operating segments.

(c) Includes stock-based compensation and excludes restructuring and other termination costs.

(d) Includes the effects of realized (gains) losses from interest rate derivatives, but excludes the effects of unrealized (gains) losses from interest rate derivatives; amount is shown net of amounts capitalized. Realized (gains) losses include settlements related to the current period interest accrual and the effect of (gains) losses on early terminated trades. Unrealized (gains) losses include changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

Natural Gas, Oil and NGL Reserves

The tables below set forth information as of December 31, 2013 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, 2013			
	Natural Gas	**Oil**	**NGL**	**Total**
	(bcf)	**(mmbbl)**	**(mmbbl)**	**(mmboe)**
Proved developed	8,583	201	177	1,809
Proved undeveloped	3,151	223	122	869
Total proved[a]	11,734	424	299	2,678

	Proved Developed	**Proved Undeveloped**	**Total Proved**
		($ in millions)	
Estimated future net revenue[b]	$ 30,414	$ 17,921	$ 48,335
Present value of estimated future net revenue[b]	$ 15,371	$ 6,305	$ 21,676
Standardized measure[b][c]			$ 17,390

Operating Division	**Natural Gas**	**Oil**	**NGL**	**Oil Equivalent**	**Percent of Proved Reserves**	**Present Value**
	(bcf)	**(mmbbl)**	**(mmbbl)**	**(mmboe)**		**($ millions)**
Southern	6,974	383	220	1,766	66%	$ 15,087
Northern	4,760	41	79	912	34%	6,589
Total	11,734	424	299	2,678	100%	$ 21,676 [b]

(a) Includes 61 bcf of natural gas, 2 mmbbl of oil and 6 mmbbl of NGL reserves owned by the Chesapeake Granite Wash Trust, 30 bcf of natural gas, 1 mmbbl of oil and 3 mmbbl of NGL of which are attributable to the noncontrolling interest holders.

(b) Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of December 31, 2013. 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, 2013. The prices used in our reserve reports were $3.67 per mcf of natural gas and $96.82 per barrel of oil, before price differential adjustments. Including the effect of price differential adjustments, the prices used in our reserve reports were $2.37 per mcf of natural gas, $95.89 per barrel of oil and $25.78 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, 2013. The amounts shown do not give effect to nonproperty-related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue differs from the standardized measure only because the former does not include the effects of estimated future income tax expenses ($4.3 billion as of December 31, 2013).

Management uses future net revenue, which is calculated without deducting estimated future income tax expenses, and the present value thereof as a 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 the present value thereof are based on prices, costs and discount factors which are consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company.

(c) Additional information on the standardized measure is presented in *Supplemental Disclosures About Natural Gas, Oil and NGL Producing Activities* included in Item 8 of this report.

As of December 31, 2013, our reserve estimates included 869 mmboe of reserves classified as proved undeveloped, compared to 1.124 bboe as of December 31, 2012. Presented below is a summary of changes in our proved undeveloped reserves (PUDs) for 2013.

	Total
	(mmboe)
Proved undeveloped reserves, beginning of period	1,124
Extensions, discoveries and other additions	351
Revisions of previous estimates	(355)
Developed	(169)
Sale of reserves-in-place	(83)
Purchase of reserves-in-place	1
Proved undeveloped reserves, end of period	869

As of December 31, 2013, there were no PUDs that had remained undeveloped for five years or more. In 2013, we invested approximately $1.472 billion, net of drilling and completion cost carries of $79 million, to convert 169 mmboe of PUDs to proved developed reserves. In 2014, we estimate that we will invest approximately $1.506 billion, net of drilling and completion cost carries of $150 million, for PUD conversion. The downward revision of 355 mmboe of PUDs in 2013 related primarily to revised well spacing in our core development area in the Marcellus Shale, the extension of our development plan beyond five years for locations outside the core of our Eagle Ford Shale acreage, the removal of PUDs with only marginally economic estimated production, and a reduction in estimated PUD reserves per well in the Mississippi Lime play.

The future net revenue attributable to our estimated proved undeveloped reserves of $17.921 billion as of December 31, 2013, and the $6.305 billion present value thereof, has been calculated assuming that we will expend approximately $8.567 billion to develop these reserves: $1.506 billion in 2014, $2.042 billion in 2015, $2.185 billion in 2016, $2.207 billion in 2017 and $600 million in 2018, 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, title issues and infrastructure availability or constraints.

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 that are not 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, 2013 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 30% from 2014 to 2015, 20% from 2015 to 2016, 15% from 2016 to 2017, 12% from 2017 to 2018 and 11% from 2018 to 2019. Of our 1.809 bboe of proved developed reserves as of December 31, 2013, 183 mmboe, or approximately 10%, 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, 2013. 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, 2013, 2012 and 2011, and the changes in quantities and standardized measure of such reserves for each of the three years then ended, are shown in *Supplemental Disclosures About Natural Gas, Oil and NGL Producing Activities* 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.

Reserves Estimation

Chesapeake's Corporate Reserves Department prepared approximately 19% 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 Director - Corporate Reserves is the technical person primarily responsible for overseeing the preparation of the Company's reserve estimates. His qualifications include the following:

- 16 years of practical experience in petroleum engineering, including eight years of this experience in the estimation and evaluation of reserves;
- Bachelor of Science degree in Chemical 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 Corporate Reserves Department reviews all of the Company's proved reserves at the close of each quarter.
- Each quarter, Corporate Reserves Department managers, the Director - Corporate Reserves, the Vice Presidents of our business units, the Senior Vice Presidents of our operating divisions and the Senior Vice President of Corporate and Strategic Planning review all significant reserves changes and all new proved undeveloped reserves additions.
- The Corporate Reserves Department reports independently of our operating divisions.

We engaged two third-party engineering firms to prepare portions of our reserves estimates comprising approximately 81% of our estimated proved reserves (by volume) at year-end 2013. The portion of our estimated proved reserves prepared by each of our third-party engineering firms as of December 31, 2013 is presented below.

	% Prepared (by Volume)	**Operating Division**
Ryder Scott Company, L.P.	51%	Northern, Southern
PetroTechnical Services, Division of Schlumberger Technology Corporation	30%	Northern

Copies of the reports issued by the engineering firms are filed with this report as Exhibits 99.1 and 99.2. 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

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, 2013	2012	2011
	($ in millions)		
Acquisition of Properties:			
Proved properties	$ 22	$ 332	$ 48
Unproved properties	997	2,981	4,736
Exploratory costs	699	2,353	2,261
Development costs	4,888	6,733	5,497
Costs incurred[(a)(b)]	$ 6,606	$ 12,399	$ 12,542

(a) Exploratory and development costs are net of joint venture drilling and completion cost carries of $884 million, $784 million and $2.570 billion in 2013, 2012 and 2011, respectively.

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

	2013	2012	2011
Capitalized interest	$ 815	$ 976	$ 727
Asset retirement obligations	$ 7	$ 32	$ 3

A summary of our exploration and development, acquisition and divestiture activities in 2013 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	1,352	698	$ 4,233	$ 169	$ 22	$ (1,252)	$ (1,130)	$ 2,042
Northern	588	287	1,354	828	—	(570)	(411)	1,201
Total	1,940	985	$ 5,587	$ 997	$ 22	$ (1,822)	$ (1,541)	$ 3,243

(a) Includes capitalized internal costs of $315 million and related capitalized interest of $815 million.

Acreage

The following table sets forth as of December 31, 2013 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	6,528	3,271	4,376	2,724	127	18	11,031	6,013
Northern	2,113	1,505	8,284	4,806	752	466	11,149	6,777
Total	8,641	4,776	12,660	7,530	879	484	22,180	12,790

Most of our leases have a three- to five-year primary term, and we manage lease expirations to ensure that we do not experience unintended material expirations. 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 noncore divestitures to high-grade our lease inventory and letting some leases expire that are no longer part of our development plans. The following table sets forth as of December 31, 2013 the expiration periods of gross and net undeveloped leasehold acres.

	Acres Expiring	
	Gross Acres	Net Acres
	(in thousands)	
Years Ending December 31:		
2014	3,335	2,219
2015	2,149	1,288
2016	1,845	1,203
After 2016	5,331	2,820
Total[a]	12,660	7,530

(a) Includes 2.189 million gross (1.132 million net) held-by-production acres 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., 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, other interest owners in Chesapeake-operated wells and other producers. We attempt to enhance the value of 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.

Natural gas and oil production is generally sold under market-sensitive short-term or spot price contracts. Natural gas and NGL 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 from the ultimate purchaser. Under percentage-of-index contracts, the price we receive is tied to published indices. Although exact percentages vary daily, as of February 2014, approximately 80% of our natural gas production was primarily sold under short-term contracts at market-sensitive prices. There were no sales to individual purchasers constituting 10% or more of total revenues (before the effects of hedging) for the years ended December 31, 2013 and 2011. Sales to Plains Marketing, L.P. represented 11% of our total revenues (before the effects of hedging) for the year ended December 31, 2012.

Our revenues and operating expenses from our marketing business increased substantially in 2013 compared to 2012. In 2013, we marketed significantly more oil and NGL from both Chesapeake-operated wells and for third parties while our marketing of natural gas was virtually unchanged. Due to the relative high prices of oil and NGL compared to natural gas, our revenues and expenses increased substantially. In addition, we entered into a variety of purchase and sales contracts with third parties for various commercial purposes including credit risk mitigation and to help meet certain of our pipeline delivery commitments. These transactions also increased our marketing revenues and operating expenses.

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. 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 2013 and 2012, we sold substantially all of our midstream business and most of our gathering assets. We continue to own the following midstream assets: (i) certain gathering pipelines primarily associated with vertical well production in the northeastern U.S.; (ii) flowlines, which are generally between 200 feet and one mile in length, for our production in each operating area; and (iii) four natural gas processing facilities located in West Virginia. See Note 15 of the notes to the consolidated financial statements included in Item 8 of this report for further discussion of the midstream sale 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.

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

Oilfield Services

We formed COS Holdings, L.L.C. (formerly Chesapeake Oilfield Services, L.L.C.) (COS) in 2011 to own and operate our oilfield services assets. COS is a diversified oilfield services company that provides a wide range of well site services, primarily to Chesapeake and its working interest partners. These services include drilling, hydraulic fracturing, oilfield rentals, rig relocation, fluid handling 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. 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 this 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 20 of the notes to our consolidated financial statements included in Item 8 of this report.

On February 24, 2014, we announced that we are pursuing strategic alternatives for COS, including a potential spin-off to Chesapeake shareholders or an outright sale. As of December 31, 2013, COS owned or leased 115 land drilling rigs, including 10 proprietary, fit-for-purpose PeakeRigs™ that utilize advanced electronic drilling technology. Also as of December 31, 2013, COS owned nine hydraulic fracturing fleets with an aggregate of 360,000 horsepower; a diversified oilfield rentals business; an oilfield trucking fleet consisting of 260 rig relocation trucks; 67 cranes and forklifts used to move drilling rigs and other heavy equipment; and 246 fluid hauling trucks.

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.

Derivative Activities

We utilize derivative instruments to provide downside price protection on 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 (FERC), the Department of Transportation (DOT), 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 oil and gas facilities are located, including the construction of well pads, pipelines, impoundments and associated access roads;
- 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, 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.

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 and other hazardous materials, the protection of the environment and standards of operation for driving. Regulations concerning equipment certification create an ongoing need for regular maintenance that is incorporated into our 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. Additional regulations specifically relate to the trucking industry, including testing and specification of equipment and product handling requirements. Our compliance with certain DOT regulations is tracked by DOT's Federal Motor Carrier Safety Administration, which develops a company-specific safety rating based on inspections of our motor carrier operations. Our safety rating can directly affect the Company's ability to obtain and renew permits and authorizations.

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

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 2013 and 2012, we sold substantially all of our midstream business and most of our gathering assets. As a result, the impact on our business of compliance with the laws and regulations described below has decreased significantly beginning in late 2012.

In addition to the environmental, health and safety laws and regulations discussed below under *Environmental, Health and Safety Matters*, a small amount of our midstream facilities is subject to federal regulation by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the DOT pursuant to the Natural Gas Pipeline Safety Act of 1968 (NGPSA) and the Pipeline Safety Improvement Act of 2002 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.

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 assertion of authority and capacity to address pipeline safety. Our natural gas pipelines have inspection and compliance programs designed to keep the facilities in compliance with applicable pipeline safety and pollution control laws and regulations.

Natural gas gathering and intrastate transportation facilities are exempt from the jurisdiction of the FERC under the Natural Gas Act. Although the FERC has made no 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 and compression 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 and 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.

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;
- prohibiting the operations of facilities deemed to be in non-compliance with permits issued pursuant to such environmental laws and regulations; and
- restricting access to certain equipment or areas to a limited set of employees or contractors who have proper certification or permits to conduct work (e.g., confined space entry and process safety maintenance requirements).

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. In addition, local land use restrictions, such as city ordinances, zoning laws, and traffic regulations, may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular.

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, state and local levels to anticipate future regulatory requirements that might be imposed to reduce the costs of compliance with any such requirements. We also 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 legally responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, persons who disposed of or arranged for the disposal of hazardous substances at the site, and any person who accepted hazardous substances for transportation to 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.

The Safe Drinking Water Act (SDWA), Underground Injection Control (UIC) program prohibits any underground injection unless authorized by a permit. Chesapeake recycles and reuses some produced water and we also dispose of produced water in Class II UIC wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. Permits for Class II UIC wells may be issued by the EPA or by a state environmental agency if EPA has delegated its UIC Program authority.

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 EPA announced in 2013 that it would reexamine and reissue the rules over the next three years. The EPA has issued updated rules regarding storage tanks and additional rules are expected. 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 for ozone, but an expected completion date for that review is not currently known.

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 a consent decree that we recently entered into with the U.S. and the West Virginia Department of Environmental Protection in connection with alleged civil violations of the CWA related to well pads, pond sites and a compressor station that we formerly owned 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.

Health and Safety

The Occupational Safety and Health Act (OSHA) and comparable state laws regulate the protection of the health and safety of our employees. The federal Occupational Safety and Health Administration has established workplace safety standards that provide guidelines for maintaining a safe workplace in light of potential hazards, such as employee exposure to hazardous substances. OSHA also requires employee training and maintenance of records, and the OSHA hazard communication standard and EPA community right-to-know regulations under the Emergency Planning and Community Right-to-Know Act of 1986 require that we organize and/or disclose information about hazardous materials used or produced in our operations.

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 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 (BLM) on federal acreage). Furthermore, our well construction practices require the 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 required to be monitored in real time at the surface during our hydraulic fracturing operations. Pressure is required to be monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations are required to be shut down if an abrupt change occurs to the injection pressure or annular pressure. These aspects of hydraulic fracturing operations are designed to prevent 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.

Hydraulic fracturing is typically regulated by state oil and gas commissions. Some states have adopted, and other states are considering adopting, regulations that impose disclosure requirements on hydraulic fracturing operations. Since early 2011, we have 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, Pennsylvania and North Dakota, which mandate disclosure of chemical additives used in hydraulic fracturing require operators to use the FracFocus website for reporting. The Pennsylvania legislature has passed Act 13, which requires, among other things, additional information in the stimulation record including water source identification and volume as well as a list of chemicals used to stimulate the well, including chemicals used in hydraulic fracturing. Certain portions of Act 13 were invalidated by the state's Supreme Court in December 2013 and are currently subject to a request for reconsideration by the state.

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. For example, 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. Certain communities in Colorado have also enacted bans on hydraulic fracturing. The EPA has asserted federal regulatory authority over hydraulic fracturing involving “diesel fuels” under the SWDA's UIC Program and has released final guidance regarding the process for obtaining a permit for hydraulic fracturing involving diesel fuel. We believe the guidance will not materially affect our operations, as we do not use diesel fuel in connection with our hydraulic fracturing. 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 BLM published a revised draft of proposed rules that would impose new requirements on hydraulic fracturing operations conducted on federal and tribal lands, including the disclosure of chemical additives used in hydraulic fracturing operations. EPA's guidance, including its interpretation of the meaning of “diesel fuel”, EPA's pending 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 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.

Global Warming and Climate Change

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

Title to Properties

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

Operating Hazards and Insurance

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

Chesapeake maintains a $75 million control of well policy that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. This insurance may not be adequate to cover all losses or exposure to liability. Chesapeake also carries a $460 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 offices in cities or towns in the areas where we conduct our operations.

Executive Officers

Robert D. Lawler, *President, Chief Executive Officer and Director*

Robert D. (“Doug”) Lawler, 47, has served as President and Chief Executive Officer since June 2013. Before joining Chesapeake, Mr. Lawler served in multiple engineering and leadership positions at Anadarko Petroleum Corporation. His positions at Anadarko included Senior Vice President, International and Deepwater Operations and member of Anadarko’s Executive Committee from July 2012 to May 2013; Vice President, International Operations from December 2011 to July 2012; Vice President, Operations for the Southern and Appalachia Region from March 2009 to July 2012; and Vice President, Corporate Planning from August 2008 to March 2009. Mr. Lawler began his career with Kerr-McGee Corporation in 1988 and joined Anadarko following its acquisition of Kerr-McGee in 2006.

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

Domenic J. (“Nick”) Dell'Osso, Jr., 37, has served as Executive Vice President and Chief Financial Officer since November 2010. 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. Mr. Dell'Osso has also served as a director of the general partner of Access Midstream Partners, L.P. (NYSE: ACMP) since June 2011.

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

Douglas J. Jacobson, 60, has served as Executive Vice President - Acquisitions and Divestitures since 2006. He served as Senior Vice President - Acquisitions and Divestitures from 1999 to 2006.

James R. Webb, *Executive Vice President - General Counsel and Corporate Secretary*

James R. Webb, 46, has served as Executive Vice President - General Counsel and Corporate Secretary since January 2014. Previously, he served as Senior Vice President - Legal and General Counsel since October 2012 and as Corporate Secretary since August 2013. Mr. Webb first joined Chesapeake in May 2012 on a contract basis as Chief Legal Counsel. Prior to joining Chesapeake, Mr. Webb was an attorney with the law firm of McAfee & Taft from 1995 to October 2012.

M. Chris Doyle, ***Senior Vice President - Operations, Northern Division***

M. Chris Doyle, 41, has served as Senior Vice President - Operations, Northern Division since August 2013. Prior to joining Chesapeake, Mr. Doyle served for 18 years at Anadarko in various positions of increasing responsibility within operations, finance and planning including international assignments in Algeria and London. His positions at Anadarko included Vice President of Operations from May to August 2013; Director, Corporate Planning from July 2012 to May 2013; General Manager - Appalachian Basin from June 2009 to July 2012; and Manager, Reserves and Planning - Southern Region from January to June 2009.

Jennifer M. Grigsby, ***Senior Vice President - Corporate and Strategic Planning***

Jennifer M. Grigsby, 45, has served as Senior Vice President - Corporate & Strategic Planning since August 2013. Prior to that time, Ms. Grigsby served as Senior Vice President and Treasurer from 2007 to August 2013 and as Corporate Secretary from 2000 to August 2013. 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, 48, 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.

John M. Kapchinske, ***Senior Vice President - Exploration & Subsurface Technology***

John M. Kapchinske, 63, has served as Senior Vice President - Exploration & Subsurface Technology since August 2013. Prior to then, he served as Senior Vice President - Geoscience from May 2011 to August 2013. He served as Vice President - Geoscience from 2005 to May 2011 and Geoscience Manager from 2001 to 2004.

Mikell J. Pigott, ***Senior Vice President - Operations, Southern Division***

Mikell J. "Jason" Pigott, 40, has served as Senior Vice President - Operations, Southern Division since August 2013. Before joining Chesapeake, Mr. Pigott served in various positions at Anadarko and focused on all aspects of developing unconventional resources. His positions at Anadarko included General Manager Eagle Ford from June to August 2013; General Manager East Texas and North Louisiana from October 2010 to June 2013; Southern & Appalachia Planning Manager from October 2009 to October 2010; Reservoir Engineering Manager East Texas and North Louisiana from July to October 2009; and Reservoir Engineering Manager Bossier from 2007 to July 2009.

John K. Reinhart, ***Senior Vice President - Operations & Technical Services***

John K. Reinhart, 45, has served as Senior Vice President - Operations & Technical Services since August 2013 and as Vice President - Operations, Eastern Division from February 2009 to August 2013. Prior to that Mr. Reinhart held various positions with Chesapeake since 2005.

Other Senior Officers

Cathlyn L. Tompkins, ***Senior Vice President - Information Technology and Chief Information Office***r

Cathlyn L. Tompkins, 53, 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.

James C. Johnson, ***Senior Vice President - Marketing***

James C. Johnson, 56, 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.

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

Jerry L. Winchester, 55, 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. Before joining Chesapeake, Mr. Winchester served as the Vice President - Boots & Coots for Halliburton Company from November 2010 to September 2011. He was the President and Chief Executive Officer of Boots & Coots International Well Control, Inc. (NYSE: WEL) from 1998 to 2010 before the company was acquired by Halliburton. Prior to joining Boots & Coots, Mr. Winchester was employed by Halliburton from 1984 to 1998, where he served in a variety of management and operational roles.

Employees

Chesapeake had approximately 10,800 employees as of December 31, 2013.

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.

Bboe. One billion barrels of oil equivalent.

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.

Boe. Barrel of oil equivalent.

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 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.

Mboe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet.

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

Mmboe. One million barrels of oil equivalent.

Mmbtu. One million btus.

Mmcf. One million cubic feet.

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 Reserves (PUDs). 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.

Realized and Unrealized Gains and Losses on Natural Gas, Oil and NGL Derivatives. Realized gains and losses includes the following items,(i) settlements of non-designated derivatives related to current period production revenues, (ii) prior period settlements for option premiums and for early-terminated derivatives originally scheduled to settle against current period production revenues, and (iii) gains and losses related to de-designated cash flow hedges originally designated to settle against current period production revenues. Unrealized gains and losses include the change in fair value of open derivatives scheduled to settle against future period production revenues offset by amounts reclassified as realized gains and losses during the period. Although we no longer designate our derivatives as cash flow hedges for accounting purposes, we believe these definitions are useful to management and investors in determining the effectiveness of our price risk management program.

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.

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.

Volumetric Production Payment (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;
- potential U.S. exports of oil and/or liquefied natural gas;
- 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
- 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 although prices have risen from their lows, they remain volatile.

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 2013, oil and NGL production accounted for only 25% of our total production but 64% of our revenue, including the effects of realized hedging, and we anticipate that approximately 62% of our 2014 revenue will come from our oil and NGL production, based on current NYMEX strip prices and our current derivative positions. Nevertheless, natural gas prices can significantly affect our future results as approximately 73% of our estimated proved reserves at December 31, 2013 were natural gas. A substantial or extended decline in natural gas, oil or NGL prices could negatively affect future revenue and the quantities of reserves that may be economically produced. Even with natural gas and oil derivatives currently in place to mitigate price risks associated with our future production (58% of our forecasted 2014 oil production through swaps and 68% of our forecasted 2014 natural gas production through swaps and three-way collars), our revenue and results of operations will be significantly exposed to changes in future commodity prices.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2013, we had long-term indebtedness of approximately $12.886 billion and unrestricted cash of $837 million, and our net indebtedness represented 40% 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 $405 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, 2013.

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 require additional capital. In addition, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default and acceleration of such indebtedness and lead to cross defaults under our other indebtedness. In this circumstance, our ability to refinance indebtedness may be limited.

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

Our exploration, development and acquisition activities and our oilfield services business require substantial capital expenditures. We intend to fund our capital expenditures through cash flows from operations and to the extent that is not sufficient, borrowings under our corporate and oilfield services revolving bank credit facilities. 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.

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 32% of our total estimated proved reserves (by volume) as of December 31, 2013 were undeveloped.

Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates at December 31, 2013 reflected a decline in the production rate on producing properties of approximately 30% in 2014 and 20% in 2015. 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 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 and declines in the prices of natural gas and oil could result in a write-down of our asset carrying values.

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, 2013, approximately 32% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflect our plans to make significant capital expenditures to convert our PUDs into proved developed reserves, including approximately $8.54 billion during the five years ending in 2018. You should be aware that the estimated development costs may not equal our actual costs, 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 remove 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, 2013 present value is based on $3.67 per mcf of natural gas and $96.82 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.

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. 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. 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.

Further, 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 quarterly ceiling test that 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, 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.

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 undeveloped properties. 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 undeveloped properties 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 undeveloped properties acquired 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 undeveloped properties 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 evaluating undeveloped properties 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 undeveloped properties, or drilling a well, whether natural gas or oil is present or may be produced economically.

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. Although we seek to actively manage our undeveloped properties, 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 commodity price risk management activities may reduce the prices we receive for our natural gas, oil and NGL sales, require us to provide collateral for derivative 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 derivative contracts 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 price risk management 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 obligations to us under certain scenarios, if any of our counterparties were to default on its obligations to us under the derivative 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.

Most of our natural gas and oil derivative contracts are with the 16 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.

Actions taken in furtherance of our strategic priorities are expected to cause us to recognize various cash and noncash charges that could negatively impact our financial condition, future results of operations or liquidity.

Certain actions that are intended to further our strategic priorities by reducing financial leverage and complexity could negatively impact our future results of operations and/or liquidity. We expect to incur various cash and noncash charges including but not limited to impairments of fixed assets, lease termination charges, financing extinguishment costs and charges for unused transportation and gathering capacity.

The oil and gas exploration and production industry is very competitive, and some of our competitors may have greater financial and other resources than we do.

We face competition in every aspect of our business, including, but not limited to, buying and selling reserves and leases, obtaining goods and services needed to operate our business and marketing natural gas, oil or NGL. Competitors include multinational oil companies, independent production companies and individual producers and operators. Some of our competitors may have greater financial and other resources than we do. As a result, these competitors may be able to address these competitive factors more effectively than we can or weather industry downturns more easily than we can.

Our performance also depends largely on the talents and efforts of highly skilled individuals and on our ability to attract new employees and to retain and motivate our existing employees. Competition in our industry for qualified employees is intense. In 2013, the Company underwent significant transformational changes that are intended to encourage standardization, efficiency and continuous improvement. Our future success is largely dependent on our employees accomplishing these goals. If we are unsuccessful in doing so, our ability to compete effectively will be diminished.

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 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.

Our ability to produce natural gas, oil and NGL economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Development activities require the use of water. For example, the hydraulic fracturing process that we employ to produce commercial quantities of natural gas and oil from many reservoirs requires the use and disposal of significant quantities of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of natural gas and oil.

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

Several states are considering adopting regulations that could impose more stringent permitting, public disclosure, and/or well construction requirements on hydraulic fracturing operations. For example, Pennsylvania is currently considering proposed regulations applicable to surface use at oil and gas well sites, including new secondary containment requirements and an abandoned and orphaned well identification program that would require operators to remediate any such wells that are damaged during current hydraulic fracturing operations. 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. 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 also 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 applicable to hydraulic fracturing 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 on hydraulic fracturing operations, 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 EPA announced in 2013 that it would reexamine and reissue these rules over the next three years. It has issued updated rules regarding storage tanks, and additional rules are expected, 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 for ozone, which could result in more stringent air emissions standards applicable to our operations. An expected completion date for that review is not currently known.

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 affecting our industry could increase our costs, reduce revenues 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.

Taxation of Independent Producers

A federal budget is expected to be proposed in early March 2014. The Company anticipates that this budget will include similar proposals related to the oil and gas industry as have been included in the past several federal budgets. These 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. In addition, legislative changes to increase the gross production tax rate have been proposed in certain states in which we operate, including Ohio and Oklahoma. 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 derivatives 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 risk management program related to the natural gas and oil we produce for our own account in order to manage the impact of low commodity prices and to predict future cash flows with greater certainty. We have used the OTC market exclusively for our natural gas and oil derivative contracts, and we also use OTC derivatives to manage risks arising from interest rate exposure. 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 which would negatively affect our revenues and cash flow during periods of low commodity prices. New position limits rules proposed under the Dodd-Frank Act could also impact our commodity hedging program and could, if enacted as proposed, affect our ability to continue to use the full scope of OTC derivatives to hedge commodity price risk in the manner that we have in the past.

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 as a means of addressing climate change could reduce demand for natural gas and oil.

A deterioration in general economic, business or industry conditions would have a material adverse effect on our results of operations, liquidity and financial condition.

In recent years, concerns over global economic conditions, energy costs, geopolitical issues, the availability and cost of credit, and the U.S. real estate and financial markets have contributed to economic uncertainty and reduced expectations for the global economy. Meanwhile, political unrest in Ukraine and Venezuela, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the U.S. or other countries also could adversely affect the global economy. These factors, combined with volatile commodity prices, tepid business and consumer confidence levels and prolonged high unemployment rates, have hindered recovery from the global economic slowdown experienced since 2008. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the U.S. or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

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 can be challenging to attract and retain qualified oilfield workers. We have also recently announced that we are pursuing strategic alternatives for our oilfield services division, including a possible spin-off or outright sale. If we are successful in effecting the separation of oilfield services from Chesapeake, we will no longer control these services and may experience increased costs and be subject to increased competition with third parties for drilling rigs, hydraulic fracturing, equipment and other products and services we now source internally. Delays in developing our natural gas and oil assets for these and other reasons could negatively affect our revenues and cash flow.

In certain 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 needs following the sale of substantially all of our midstream business and most of our gathering assets in 2012 and 2013. 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 weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

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 2013 and 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 former 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. In other litigation, the Company is defending against claims by royalty owners alleging that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. Adverse results in pending cases would cause our obligations to royalty owners to increase and would negatively impact our future results of operations.

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 operations. 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.

An interruption in operations at our headquarters could adversely affect our business.

Our headquarters are located in Oklahoma City, Oklahoma, an area that experiences severe weather events, including tornadoes. Our information systems and administrative and management process are primarily provided to our various drilling projects throughout the United States from this location, which could be disrupted if a catastrophic event, such as a tornado, power outage or act of terror, destroyed or severely damaged our headquarters. Any such catastrophic event could harm our ability to conduct normal operations and could adversely affect our business.

ITEM 1B. *Unresolved Staff Comments*

Not applicable.

ITEM 2. *Properties*

Information regarding our properties is included in Item 1 and in the Supplementary Information 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. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for information regarding our estimation and provision for potential losses related to litigation and regulatory proceedings.

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. 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. Chesapeake and the officer and director defendants moved for summary judgment on grounds of loss causation and materiality on December 28, 2011, and the motion was granted as to all claims as a matter of law on March 29, 2013. Final judgment in favor of Chesapeake and the officer and director defendants was entered on June 21, 2013, and the plaintiff filed a notice of appeal on July 19, 2013 in the U.S. Court of Appeals for the Tenth Circuit.

A derivative action relating to the July 2008 offering filed in the U.S. District Court for the Western District of Oklahoma on September 6, 2011 is pending. Following the denial on September 28, 2012 of its motion to dismiss and pursuant to court order, nominal defendant Chesapeake filed an answer in the case on October 12, 2012. By stipulation between the parties, the case is stayed pending resolution of the Tenth Circuit appeal.

2012 Securities and Shareholder Litigation. 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 its former Chief Executive Officer (CEO), Aubrey K. McClendon. 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 asserted claims under Sections 10(b) (and Rule 10b-5 promulgated thereunder) 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. On December 6, 2012, the Company and other defendants filed a motion to dismiss the action. On April 10, 2013, the Court granted the motion, and on April 16, 2013 entered judgment against the plaintiff and dismissed the complaint with prejudice. The plaintiff filed a notice of appeal on June 14, 2013 in the U.S. Court of Appeals for the Tenth Circuit. Briefing on the appeal was complete on August 2, 2013, and on November 18, 2013, argument was heard.

A related federal consolidated derivative action and an Oklahoma state court derivative action are stayed pursuant to the parties' stipulation pending resolution of the appeal in the federal securities class action.

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. On August 21, 2012, the District Court granted the Company's motion to dismiss for lack of derivative standing, and the plaintiff appealed the ruling on December 6, 2012.

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

The Company has received, from the Antitrust Division of the U.S. Department of Justice (DOJ) and certain state governmental agencies, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state laws relating to our purchase and lease of oil and gas rights in various states. Chesapeake has engaged in discussions with the DOJ and state agencies and continues to respond to such subpoenas and demands, including a subpoena issued by the Michigan Department of Attorney General relating to its investigation of possible violations of that state's criminal solicitation law.

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, 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. Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits allege that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. The Company is defending against certain pending claims, has resolved a number of claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits.

Environmental Proceedings

On December 19, 2013, our subsidiary Chesapeake Appalachia, LLC (CALLC) entered into a consent decree with the EPA, the DOJ and the West Virginia Department of Environmental Protection (WVDEP) to resolve alleged violations of the CWA and the West Virginia Water Pollution Control Act at 27 sites in West Virginia. In a complaint filed against CALLC the same day in the U.S. District Court for the Northern District of West Virginia, the EPA and WVDEP alleged that CALLC impounded streams and discharged sand, dirt, rocks and other fill material into streams and wetlands without a federal permit in order to construct well pads, impoundments, road crossings and other facilities related to natural gas extraction. The consent decree, also lodged on December 19, 2013, is subject to court approval.

The consent decree requires CALLC to pay a civil penalty of approximately $3 million, to be divided evenly between the U.S. and the state of West Virginia. The consent decree settlement also requires that CALLC restore the affected wetlands and streams in accordance with an agreed plan, monitor the restored sites for up to 10 years to assure the success of the restoration, and implement a comprehensive compliance program to ensure future compliance with the CWA and applicable West Virginia law. To offset the impacts to sites, CALLC is required by the consent decree to perform compensatory mitigation, which will likely involve purchasing credits from a wetland mitigation bank located in a local watershed. Eleven of the sites covered by the consent decree were subject to orders for compliance issued by the EPA in 2010 and 2011. Since then, CALLC has been correcting the alleged violations and restoring those sites in compliance with EPA's orders. The settlement resolves alleged violations of both the CWA and state law.

In a related case, in December 2012, CALLC pled guilty to three misdemeanor violations of the CWA for unauthorized discharge at one of the sites subject to the consent decree of crushed stone and gravel into a local stream to create a roadway to improve access to a drilling site. CALLC paid a $600,000 penalty and has fully restored the site. We believe that CALLC is in compliance with the terms of probation. By operation of law, a CWA conviction triggers “disqualification”, by which the disqualified entity is prohibited from receiving federal contracts or benefits until the EPA certifies that the conditions giving rise to the conviction have been corrected. Disqualification of CALLC has not had, and we do not expect it to have, a material adverse impact on our business.

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

Not applicable.

PART II

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

Price Range of Common Stock and Dividends

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

	Common Stock		Dividend
	High	Low	Declared
Year Ended December 31, 2013:			
Fourth Quarter	$ 29.06	$ 25.06	$ 0.0875
Third Quarter	$ 27.46	$ 20.30	$ 0.0875
Second Quarter	$ 22.86	$ 18.21	$ 0.0875
First Quarter	$ 22.97	$ 16.32	$ 0.0875
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

As of February 11, 2014, there were approximately 2,200 holders of record of our common stock and approximately 331,500 beneficial owners.

Although 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, 2013:

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, 2013 through October 31, 2013	44,158	$	27.74	—	—
November 1, 2013 through November 30, 2013...	566,370	$	26.00	—	—
December 1, 2013 through December 31, 2013...	275,242	$	26.52	—	—
Total	885,770	$	26.25	—	—

(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, 2013, 2012, 2011, 2010 and 2009. The data are derived from our audited consolidated financial statements, revised to reflect the reclassification of certain items to conform to current period presentation. 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 thereto, appearing in Items 7 and 8, respectively, of this report.

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	($ in millions, except per share data)				
REVENUES:					
Natural gas, oil and NGL	$ 7,052	$ 6,278	$ 6,024	$ 5,647	$ 5,049
Marketing, gathering and compression	9,559	5,431	5,090	3,479	2,463
Oilfield services	895	607	521	240	190
Total Revenues	17,506	12,316	11,635	9,366	7,702
OPERATING EXPENSES:					
Natural gas, oil and NGL production	1,159	1,304	1,073	893	876
Production taxes	229	188	192	157	107
Marketing, gathering and compression	9,461	5,312	4,967	3,352	2,316
Oilfield services	736	465	402	208	182
General and administrative	457	535	548	453	349
Restructuring and other termination costs	248	7	—	—	34
Natural gas, oil and NGL depreciation, depletion and amortization	2,589	2,507	1,632	1,394	1,371
Depreciation and amortization of other assets	314	304	291	220	244
Impairment of natural gas and oil properties	—	3,315	—	—	11,000
Impairments of fixed assets and other	546	340	46	21	130
Net (gains) losses on sales of fixed assets	(302)	(267)	(437)	(137)	38
Total Operating Expenses	15,437	14,010	8,714	6,561	16,647
INCOME (LOSS) FROM OPERATIONS	2,069	(1,694)	2,921	2,805	(8,945)
OTHER INCOME (EXPENSE):					
Interest expense	(227)	(77)	(44)	(19)	(113)
Earnings (losses) on investments	(226)	(103)	156	227	(39)
Gains (losses) on sales of investments	(7)	1,092	—	(129)	(40)
Losses on purchases of debt and extinguishment of other financing	(193)	(200)	(176)	(16)	(162)
Other income	26	8	23	16	11
Total Other Income (Expense)	(627)	720	(41)	79	(343)
INCOME (LOSS) BEFORE INCOME TAXES	1,442	(974)	2,880	2,884	(9,288)
INCOME TAX EXPENSE (BENEFIT):					
Current income taxes	22	47	13	—	4
Deferred income taxes	526	(427)	1,110	1,110	(3,487)
Total Income Tax Expense (Benefit)	548	(380)	1,123	1,110	(3,483)
NET INCOME (LOSS)	894	(594)	1,757	1,774	(5,805)
Net income attributable to noncontrolling interests	(170)	(175)	(15)	—	(25)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	724	(769)	1,742	1,774	(5,830)
Preferred stock dividends	(171)	(171)	(172)	(111)	(23)
Premium on purchase of preferred shares of a subsidiary	(69)	—	—	—	—
Earnings allocated to participating securities	(10)	—	—	—	—
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 474	$ (940)	$ 1,570	$ 1,663	$ (5,853)

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	($ in millions, except per share data)				
STATEMENT OF OPERATIONS DATA (continued):					
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ 0.73	$ (1.46)	$ 2.47	$ 2.63	$ (9.57)
Diluted	$ 0.73	$ (1.46)	$ 2.32	$ 2.51	$ (9.57)
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.35	$ 0.35	$ 0.3375	$ 0.30	$ 0.30
CASH FLOW DATA:					
Cash provided by operating activities	$ 4,614	$ 2,837	$ 5,903	$ 5,117	$ 4,356
Cash used in investing activities	$ (2,967)	$ (4,984)	$ (5,812)	$ (8,503)	$ (5,462)
Cash provided by (used in) financing activities	$ (1,097)	$ 2,083	$ 158	$ 3,181	$ (336)
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 41,782	$ 41,611	$ 41,835	$ 37,179	$ 29,914
Long-term debt, net of current maturities	$ 12,886	$ 12,157	$ 10,626	$ 12,640	$ 12,295
Total equity	$ 18,140	$ 17,896	$ 17,961	$ 15,264	$ 12,341

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Financial Data

The following table sets forth certain information regarding our 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,		
	2013	2012	2011
Net Production:			
Natural gas (bcf)	1,095	1,129	1,004
Oil (mmbbl)	41	31	17
NGL (mmbbl)	21	18	15
Oil equivalent (mmboe)[(a)]	244	237	199
Natural Gas, Oil and NGL Sales ($ in millions):			
Natural gas sales	$ 2,430	$ 2,004	$ 3,133
Natural gas derivatives - realized gains (losses)	9	328	1,656
Natural gas derivatives - unrealized gains (losses)	(52)	(331)	(669)
Total natural gas sales	2,387	2,001	4,120
Oil sales	3,911	2,829	1,523
Oil derivatives - realized gains (losses)	(108)	39	(60)
Oil derivatives - unrealized gains (losses)	280	857	(128)
Total oil sales	4,083	3,725	1,335
NGL sales	582	526	603
NGL derivatives - realized gains (losses)	—	(9)	(42)
NGL derivatives - unrealized gains (losses)	—	35	8
Total NGL sales	582	552	569
Total natural gas, oil and NGL sales	$ 7,052	$ 6,278	$ 6,024
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 2.22	$ 1.77	$ 3.12
Oil ($ per bbl)	$ 95.17	$ 90.49	$ 89.80
NGL ($ per bbl)	$ 27.87	$ 29.89	$ 40.96
Oil equivalent ($ per boe)	$ 28.33	$ 22.61	$ 26.42
Average Sales Price (including realized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 2.23	$ 2.07	$ 4.77
Oil ($ per bbl)	$ 92.53	$ 91.74	$ 86.25
NGL ($ per bbl)	$ 27.87	$ 29.37	$ 38.12
Oil equivalent ($ per boe)	$ 27.92	$ 24.12	$ 34.23
Other Operating Income[(b)] ($ in millions):			
Marketing, gathering and compression net margin	$ 98	$ 119	$ 123
Oilfield services net margin	$ 159	$ 142	$ 119
Other Operating Income[(b)] ($ per boe):			
Marketing, gathering and compression net margin	$ 0.40	$ 0.50	$ 0.62
Oilfield services net margin	$ 0.65	$ 0.60	$ 0.60

	Years Ended December 31,		
	2013	2012	2011
Expenses ($ per boe):			
Natural gas, oil and NGL production	$ 4.74	$ 5.50	$ 5.39
Production taxes	$ 0.94	$ 0.79	$ 0.96
General and administrative expenses[c]	$ 1.86	$ 2.26	$ 2.75
Natural gas, oil and NGL depreciation, depletion and amortization	$ 10.59	$ 10.58	$ 8.20
Depreciation and amortization of other assets	$ 1.28	$ 1.28	$ 1.46
Interest expense[d]	$ 0.65	$ 0.35	$ 0.18
Interest Expense ($ in millions):			
Interest expense	$ 169	$ 84	$ 30
Interest rate derivatives – realized (gains) losses[e]	(9)	(1)	7
Interest rate derivatives – unrealized (gains) losses[f]	67	(6)	7
Total interest expense	$ 227	$ 77	$ 44

(a) Oil 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. In recent years, the price for a bbl of oil and NGL has been significantly higher than the price for six mcf of natural gas.

(b) Includes revenue and operating costs and excludes depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See *Depreciation and Amortization of Other Assets, Impairments of Fixed Assets and Other* and *Net (Gains) Losses on Sales of Fixed Assets* under *Results of Operations* for details of the depreciation and amortization and impairments of assets and net gains or losses on sales of fixed assets associated with our marketing, gathering and compression and oilfield services operating segments.

(c) Includes stock-based compensation and excludes restructuring and other termination costs.

(d) Includes the effects of realized (gains) losses from interest rate derivatives, but excludes the effects of unrealized (gains) losses from interest rate derivatives; amount is shown net of amounts capitalized.

(e) Realized (gains) losses include settlements related to the current period interest accrual and the effect of (gains) losses on early terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item.

(f) Unrealized (gains) losses include changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

Overview

For an overview of our business and strategy, please see *Our Business* and *Business Strategy* in Item 1 of this report.

We own interests in approximately 46,800 natural gas and oil wells that produced approximately 665 mboe per day in the 2013 fourth quarter, net to our interest. Our 2013 production of 244 mmboe consisted of 1.095 tcf of natural gas (75% on an oil equivalent basis), 41 mmbbls of oil (17% on an oil equivalent basis) and 21 mmbbls of NGL (8% on an oil equivalent basis). Liquids represented 25% of total production for 2013, up from 20% in 2012. Our daily production for 2013 averaged approximately 670 mboe, an increase of 3% from 2012. Compared to 2012, our natural gas production in 2013 decreased by 3%, or 85 mmcf per day; our oil production increased by 32%, or approximately 27,200 bbls per day; and our NGL production increased by 19%, or approximately 9,100 bbls per day.

In 2013, we operated an average of 71 rigs, a decrease of 60 rigs compared to 2012, and invested approximately $5.5 billion in drilling and completion costs compared to approximately $8.8 billion in 2012. Drilling and completion costs were lower in 2013 than in 2012 as Chesapeake drilled and completed fewer wells. In addition, our capital efficiency improvements in 2013 became more evident as we continued to drive well costs down.

Net expenditures for the acquisition of unproved properties were approximately $205 million during 2013 compared to approximately $1.7 billion in 2012. Through 2012, the Company invested heavily in unproved properties and now holds a substantial inventory of resources that provides a foundation for future growth. Other capital expenditures were approximately $1.0 billion during 2013 compared to approximately $3.4 billion during 2012. The reduction in other capital expenditures in 2013 from 2012 is primarily the result of our sale of substantially all of our midstream business and most of our gathering assets in 2012 and 2013 and a reduction in capital expenditures for our oilfield services business.

Based on planned activity levels for 2014, we project that 2014 total capital expenditures will be $5.2 - $5.6 billion, an approximate 20% decrease from $6.8 billion of total capital expenditures in 2013.

Divestitures

An essential part of our business strategy in 2013 was using the proceeds from divestitures to fund the spending gap between cash flow from operations and our capital expenditures, to reduce financial leverage and complexity and further enhance our liquidity. In 2013, we generated aggregate net proceeds of approximately $4.4 billion from the sale of natural gas and oil properties, midstream and other assets that we deemed were noncore or did not fit in our long-term plans and through our entry into a strategic joint venture.

We will continue to pursue opportunities to high-grade our portfolio to focus on assets that best fit our strategy of profitable growth from captured resources with sales that we believe will be value accretive and enable us to further reduce financial complexity and lower overall leverage, but our 2014 capital budget is not dependent on divestitures.

On February 24, 2014, we announced that we are pursuing strategic alternatives for our oilfield services business, COS, including a potential spin-off to Chesapeake shareholders or an outright sale. See *Oilfield Services* in Item I of this report for a further description of our oilfield services business. In addition, in January 2014 we received $209 million of net proceeds from the sale of our common equity ownership in Chaparral Energy, Inc. Also, in connection with certain assets sales in 2012 and 2013, we believe that we will receive proceeds in excess of $150 million in 2014 that were held back for title review and other purposes at the time of closing (see Haynesville and Eagle Ford divestitures and Mississippi Lime joint venture below). Currently, we are marketing or currently have under contract certain real estate and other non-E&P assets, excluding COS, that are expected to generate proceeds of more than $650 million during 2014. Together, the items listed above and excluding any proceeds we may receive from a COS transaction, are expected to generate proceeds of approximately $1 billion, and we believe the sale of these assets will have minimal impact on our 2014 operating cash flow guidance.

Major 2013 Natural Gas and Oil Property Sales

In November 2013, we sold a wholly owned subsidiary, MKR Holdings, L.L.C. (MKR), to Chief Oil and Gas and two of its working interest partners, Enerplus and Tug Hill. Net proceeds from the transaction were approximately $490 million. MKR held producing wells and undeveloped acreage in the Marcellus Shale in Bradford, Lycoming, Sullivan, Susquehanna and Wyoming counties, Pennsylvania.

In July 2013, we sold assets in the Haynesville Shale to EXCO Operating Company, LP (EXCO) for net proceeds of approximately $257 million. Subsequent to closing, we have received approximately $47 million of additional net proceeds for post-closing adjustments. The assets sold included our operated and non-operated interests in approximately 9,600 net acres in DeSoto and Caddo parishes, Louisiana.

Also in July 2013, we sold assets in the northern Eagle Ford Shale to EXCO for net proceeds of approximately $617 million. Subsequent to closing, we have received approximately $32 million of additional net proceeds for post-closing adjustments and may receive up to $64 million of additional net proceeds for further post-closing adjustments. The assets sold included approximately 55,000 net acres in Zavala, Dimmit, La Salle and Frio counties, Texas.

2013 Natural Gas and Oil Property Joint Venture

In June 2013, we completed a strategic joint venture with Sinopec International Petroleum Exploration and Production Corporation (Sinopec) in which Sinopec purchased a 50% undivided interest in approximately 850,000 acres (425,000 acres net to Sinopec) in the Mississippi Lime play in northern Oklahoma. Total consideration for the transaction was approximately $1.020 billion in cash, of which approximately $949 million of net proceeds was received upon closing. We also received an additional $90 million at closing related to closing adjustments for activity between the effective date and closing date of the transaction. We may receive up to an additional $71 million of net proceeds for post-closing adjustments. All future exploration and development costs in the joint venture will be shared proportionately between the parties with no drilling carries involved.

Major 2013 Midstream Asset Sales

In August 2013, our wholly owned subsidiary, Chesapeake Midstream Development, L.L.C. (CMD), sold its wholly owned midstream subsidiary, Mid-America Midstream Gas Services, L.L.C. (MAMGS), to SemGas, L.P. (SemGas), a wholly owned subsidiary of SemGroup Corporation, for net proceeds of approximately $306 million. We recorded a $141 million gain associated with the transaction. MAMGS owned certain gathering and processing assets located in the Mississippi Lime play, and the transaction with SemGas included a new long-term fixed-fee gathering and processing agreement covering acreage dedication areas in the Mississippi Lime play.

In May 2013, CMD sold its wholly owned subsidiary, Granite Wash Midstream Gas Services, L.L.C. (GWMGS), to MarkWest Oklahoma Gas Company, L.L.C., a wholly owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE), for net proceeds of approximately $252 million. We recorded a $105 million gain associated with this transaction. GWMGS owned certain midstream assets in the Anadarko Basin that service the Granite Wash and Hogshooter formations. The transaction with MWE included new long-term fixed-fee agreements for gas gathering, compression, treating and processing services.

In March 2013, CMD sold its interest in certain gathering system assets in Pennsylvania to Western Gas Partners, LP (NYSE:WES) for net proceeds of approximately $134 million. We recorded a $55 million gain associated with this transaction.

Liquidity and Capital Resources

Liquidity Overview

As of December 31, 2013, we had approximately $4.909 billion in cash availability (defined as unrestricted cash on hand plus borrowing capacity under our revolving bank credit facilities) compared to $4.338 billion as of December 31, 2012. During 2013, we decreased our debt, net of unrestricted cash, by approximately $284 million, to $12.049 billion. As of December 31, 2013, we had negative working capital of approximately $1.859 billion compared to negative working capital of approximately $2.854 billion (excluding current maturity of debt) as of December 31, 2012. Historically, working capital deficits have existed primarily because our capital spending has exceeded our cash flow from operations.

Our business is capital intensive. During the year ended December 31, 2013, our capital expenditures exceeded cash flow from operations, and we filled this spending gap with borrowings and proceeds from our joint venture with Sinopec and from sales of assets that we determined were noncore or did not fit our long-term plans. In addition, as of December 31, 2013 we had full availability under our corporate revolving bank credit facility, providing significant additional liquidity if necessary. For 2014, we are projecting that our capital expenditures will approximate our cash flow from operations.

Proceeds from any asset sales completed in 2014 and beyond may be used to reduce financial leverage and complexity and further enhance our liquidity. While furthering our strategic priorities, certain actions that would reduce financial leverage and complexity could negatively impact our future results of operations. We may incur various cash charges including but not limited to lease termination charges, financing extinguishment costs and charges for unused transportation and gathering capacity.

To add more certainty to our future estimated cash flows, we currently have downside price protection, in the form of over-the-counter derivative contracts, on approximately 68% of our 2014 estimated natural gas production at an average price of $4.15 per mcf and 58% of our 2014 estimated oil production at an average price of $93.92 per bbl. See *Quantitative and Qualitative Disclosures about Market Risk* in Item 7A of this report. Our use of derivative contracts allows us to reduce the effect of price volatility on our cash flows and EBITDA (defined as earnings before interest, taxes, depreciation, depletion and amortization), but the amount of estimated production subject to derivative contracts for any period depends on our outlook on future prices and risk assessment.

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 in future periods 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 corporate revolving bank credit facility agreement that increased the required 4.00 to 1.00 indebtedness to EBITDA ratio for the quarter ended September 30, 2012 and the four subsequent quarters. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for discussion of the terms of the amendment and the early termination of its provisions on June 28, 2013. For the quarter ended December 31, 2013 and the four previous quarters, our indebtedness to EBITDA ratio was less than 4.00 to 1.00, the ratio currently in effect and which 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, secured hedging facility, equipment master lease agreements and term loan.

Based upon our 2014 capital expenditure budget, our forecasted operating cash flow and projected levels of indebtedness, we are projecting that we will be in compliance with the financial maintenance covenants of our corporate revolving bank credit facility. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties pursuant to various agreements 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. 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 the years ended December 31, 2013, 2012 and 2011. See *Divestitures* above and Notes 8, 12, 13 and 15 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of sales of natural gas and oil assets, other assets, investments, and preferred interests and noncontrolling interests in subsidiaries.

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
Cash provided by operating activities	$ 4,614	$ 2,837	$ 5,903
Sales of natural gas and oil assets:			
Eagle Ford	636	—	—
Marcellus	490	—	—
Haynesville	304	—	—
Permian Basin	—	3,130	—
Texoma	—	572	—
Chitwood Knox	—	540	—
Fayetteville Shale	—	—	4,270
SIPC (Mississippi Lime) joint venture	1,025	—	—
TOT (Utica) joint venture	—	—	610
CNOOC (Niobrara) joint venture	—	—	553
TOT (Barnett) joint venture	—	—	425
Volumetric production payments	—	744	849
Joint venture leasehold	58	272	511
Other natural gas and oil properties	954	626	433
Total sales of natural gas, oil and other assets	3,467	5,884	7,651
Sales of other assets:			
Sale of Chesapeake Midstream Operating, L.L.C. (CMO)	—	2,160	—
Sale of Appalachia Midstream Services, L.L.C. (AMS)	—	—	879
Sale of Mid-America Midstream Gas Services, L.L.C. (MAMGS)	306	—	—
Sale of Granite Wash Midstream Gas Services, L.L.C. (GWMGS)	252	—	—
Sales of other property and equipment	364	332	433
Total proceeds from sales of other property and equipment	922	2,492	1,312
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 long-term debt, net	2,274	6,985	1,614
Proceeds from sales of other investments	115	—	—
Cash received from financing derivatives[(a)]	—	—	1,043
Other	187	84	442
Total other sources of cash and cash equivalents	2,576	10,319	4,759
Total sources of cash and cash equivalents	$11,579	$21,532	$19,625

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

Cash provided by operating activities was $4.614 billion in 2013 compared to $2.837 billion in 2012 and $5.903 billion in 2011. The increase in cash provided by operating activities from 2012 to 2013 is primarily the result of an increase in prices received for natural gas, oil and NGL sold (excluding the effect of gains or losses on derivatives) from $22.61 per boe in 2012 to $28.33 per boe in 2013, an increase in oil and NGL sales volumes and decreases in certain of our operating expenses per unit. The decline in cash provided by operating activities from 2011 to 2012 is primarily the result of a decrease in the natural gas price received for natural gas sold (excluding the effect of gains or losses on derivatives) from $3.12 per mcf in 2011 to $1.77 per mcf in 2012. 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 debt in 2013, 2012 and 2011. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

	Years Ended December 31,					
	2013		2012		2011	
	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds
	($ in millions)					
Senior notes	$ 2,300	$ 2,274	$ 1,300	$ 1,263	$ 1,650	$ 1,614
Term loans	—	—	6,000	5,722	—	—
Total	$ 2,300	$ 2,274	$ 7,300	$ 6,985	$ 1,650	$ 1,614

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 $7.669 billion and repaid $7.682 billion in 2013, borrowed $20.318 billion and repaid $21.650 billion in 2012 and borrowed $15.509 billion and repaid $17.466 billion in 2011 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 is 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. Prior to June 15, 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 2013, 2012 and 2011:

	Years Ended December 31, 2013	2012	2011
	($ in millions)		
Natural Gas and Oil Expenditures:			
Drilling and completion costs[(a)]	$ (5,490)	$ (8,707)	$ (7,257)
Acquisitions of proved properties	(22)	(342)	(48)
Acquisitions of unproved properties	(280)	(2,043)	(4,296)
Geological and geophysical costs	(33)	(170)	(192)
Interest capitalized on unproved properties	(811)	(829)	(648)
Total natural gas and oil expenditures	(6,636)	(12,091)	(12,441)
Other Uses of Cash and Cash Equivalents:			
Additions to other property and equipment[(b)]	(972)	(2,651)	(2,009)
Acquisition of drilling company	—	—	(339)
Payments on credit facility borrowings, net	(13)	(1,332)	(1,957)
Cash paid to purchase debt	(2,141)	(4,000)	(2,015)
Cash paid for prepayment of mortgage	(55)	—	—
Dividends paid	(404)	(398)	(379)
Cash paid to purchase preferred shares of subsidiary	(212)	—	—
Cash paid to extinguish other financing	(141)	—	—
Distributions to noncontrolling interest owners	(215)	(218)	(9)
Cash paid for financing derivatives[(c)]	(91)	(37)	—
Additions to investments	(44)	(395)	—
Other	(105)	(474)	(227)
Total other uses of cash and cash equivalents	(4,393)	(9,505)	(6,935)
Total uses of cash and cash equivalents	$ (11,029)	$ (21,596)	$ (19,376)

(a) Net of $884 million, $784 million and $2.570 billion in drilling and completion carries received from our joint venture partners during 2013, 2012 and 2011, respectively.

(b) Includes approximately $240 million and $36 million (excluding lease termination costs) in 2013 and 2012, respectively, to purchase rigs and compressors subject to sale leaseback agreements, lowering our future operating lease commitments. See Notes 4 and 16 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of these transactions.

(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 and development of natural gas and oil properties. Historically, a significant use was also for the acquisition of leasehold and construction and acquisition of other property and equipment. During 2012, our average operated rig count was 131 rigs as we were quickly ramping up our liquids-focused drilling while gradually ramping down drilling of natural gas wells. During 2013, our average rig count was 71 operated rigs, and as of February 20, 2014, our rig count was 63 operated rigs. Our 2013 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 enabled us to hold by production the related leasehold according to the terms of our leases.

Our unproved property leasehold acquisition costs were $280 million during 2013, a substantial decrease from prior years. Through 2012, the Company invested heavily in unproved properties and now holds a substantial inventory of resources that provides a foundation for future growth. We believe that focusing on profitable and efficient growth from captured resources will allow us to deliver attractive profit margins and financial returns in the future through all phases of the commodity price cycle.

Capital expenditures related to additions to property and equipment associated with our midstream, oilfield services and other fixed assets of $972 million, $2.651 billion and $2.009 billion during 2013, 2012 and 2011, respectively, were primarily related to the expansion of our gathering systems and the growth of our oilfield services assets, in particular our hydraulic fracturing assets. The $1.679 billion reduction of such expenditures in 2013 from 2012 is primarily the result of our sale of substantially all of our midstream business and most of our gathering assets in 2012 and 2013 and a reduction in capital expenditures for our oilfield services business.

In late 2012, we fully repaid the $4.0 billion term loan that we established in May 2012 with cash proceeds from asset sales and proceeds from the issuance of the $2.0 billion term loan that we established in November 2012. We recorded approximately $200 million of losses associated with this repayment, including the write-off of $86 million of deferred charges.

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.

We paid dividends on our common stock of $233 million, $227 million and $207 million in 2013, 2012 and 2011, respectively. We paid dividends on our preferred stock of $171 million, $171 million and $172 million in 2013, 2012 and 2011, respectively.

Bank Credit Facilities

During 2013, we had two revolving bank credit facilities as sources of liquidity.

	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, 2013	$	—	$	405
Letters of credit outstanding as of December 31, 2013	$	23	$	—

(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. (COO).

Although the applicable interest rates under our corporate credit facility fluctuate 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 credit facility agreement as of December 31, 2013. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the terms of our corporate credit facility, including the terms of an amendment that increased the required indebtedness to EBITDA ratio as of September 30, 2012 and the subsequent two quarters.

Our indebtedness to EBITDA ratio as of December 31, 2013 was approximately 2.70 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 or non-recurring expenses, and is calculated on a pro forma basis to give effect to any acquisitions, divestitures or other adjustments.

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 bear interest at a variable interest rate and are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries for this facility, which are unrestricted subsidiaries under Chesapeake's senior notes, contingent convertible senior notes, term loan, corporate revolving bank credit facility, secured hedging facility and equipment master lease agreements). 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.

Hedging Facility

We have a multi-counterparty secured hedging facility with 16 counterparties that have committed to provide approximately 1.063 bboe of hedging capacity for natural gas, oil and NGL price derivatives and 1.063 bboe 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 11 of the notes to our consolidated financial statements included in Item 8 of this report.

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. We used the proceeds from the term loan, along with proceeds from assets sales, to repay our $4.0 billion term loan credit facility established in May 2012. 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 facility bear interest at a variable rate and the facility may be voluntarily repaid at any time, subject to applicable premiums, as provided in the agreement. 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 term loan discussed above, our long-term debt consisted of the following as of December 31, 2013:

	December 31, 2013
	($ in millions)
9.5% senior notes due 2015[(a)]	$ 1,265
3.25% senior notes due 2016	500
6.25% euro-denominated senior notes due 2017[(b)]	473
6.5% senior notes due 2017	660
6.875% senior notes due 2018	97
7.25% senior notes due 2018	669
6.625% senior notes due 2019[(c)]	650
6.625% senior notes due 2020	1,300
6.875% senior notes due 2020	500
6.125% senior notes due 2021	1,000
5.375% senior notes due 2021	700
5.75% senior notes due 2023	1,100
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)]	(324)
Interest rate derivatives[(f)]	13
Total senior notes, net	$ 10,514

(a) Due February 2015.

(b) The principal amount shown is based on the exchange rate of $1.3743 to €1.00 as of December 31, 2013. See Note 11 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 was $303 million as of December 31, 2013 associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(f) See Note 11 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, interest rate and foreign currency 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. As of December 31, 2013, our natural gas, oil and interest rate derivative instruments were spread among 16 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 substantially all of our natural gas, oil and NGL derivatives.

Our accounts receivable are primarily from purchasers of natural gas, oil and NGL ($1.548 billion as of December 31, 2013) and exploration and production companies that own interests in properties we operate ($478 million as of December 31, 2013). 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 2013, 2012 and 2011, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables.

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, 2013, these arrangements and transactions included (i) operating lease agreements, (ii) VPPs (to purchase production 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, 2013.

	Payments Due By Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			($ in millions)		
Long-term debt:					
Principal	$ 13,230	$ —	$ 2,566	$ 5,414	$ 5,250
Interest	4,615	753	1,267	987	1,608
Operating lease obligations[a]	375	118	191	65	1
Purchase obligations[b]	17,261	2,069	3,755	3,710	7,727
Unrecognized tax benefits[c]	323	6	—	317	—
Standby letters of credit	23	23	—	—	—
Deferred premium on call options	268	83	185	—	—
Other	93	15	28	16	34
Total contractual cash obligations[d]	$ 36,188	$ 3,067	$ 7,992	$ 10,509	$ 14,620

(a) 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. Also, see Note 23 for a description of operating lease obligations reduced subsequent to December 31, 2013.

(b) See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for a description of gathering, processing and transportation agreements, drilling contracts and property and equipment purchase commitments.

(c) See Note 6 of the notes to our consolidated financial statements included in Item 8 of this report for a description of unrecognized tax benefits.

(d) This table does not include the estimated discounted liability for future dismantlement, abandonment and restoration costs of natural gas and oil properties or derivative liabilities. See Notes 19 and 11, respectively, of the notes to our consolidated financial statements included in Item 8 of this report for more information on our asset retirement obligations and derivatives. This table also 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 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 our full cost ceiling test for impairment purposes and in determining our standardized measure. The amount of these VPP-related production expenses and taxes, based on cost levels as of December 31, 2013 pursuant to SEC reporting requirements, was estimated to be approximately $799 million in total and $163 million for the next twelve months on an undiscounted basis and approximately $648 million and $155 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 produced that are 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 and 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of commitments and VPPs, respectively.

Derivative 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 derivative program at its quarterly board meetings. We believe we have sufficient internal controls to prevent unauthorized trading. As of December 31, 2013, our natural gas and oil derivative instruments consisted of swaps, collars, options, swaptions and basis protection swaps. Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* contains a description of each of these instruments and gains and losses on natural gas, oil and NGL derivatives during 2013, 2012 and 2011. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our commodity derivative activities allow 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 a loss. Commodity markets are volatile and Chesapeake's derivative activities are dynamic.

Mark-to-market positions under commodity derivative contracts fluctuate with commodity prices. As described under *Hedging Facility* in Note 11 of the notes to our consolidated financial statements included in Item 8 of this report, 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 and oil derivative contracts as of December 31, 2013 and 2012 are provided below. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* for additional information concerning the fair value of our natural gas and oil derivative instruments.

	December 31, 2013	December 31, 2012
	($ in millions)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ (23)	$ 24
Natural gas three-way collars	(7)	—
Natural gas call options	(210)	(240)
Natural gas basis protection swaps	3	(15)
Fixed-price oil swaps	(50)	68
Oil call options	(265)	(748)
Oil call swaptions	—	(13)
Oil basis protection swaps	1	—
Estimated fair value	$ (551)	$ (924)

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. As of December 31, 2013, 2012 and 2011, accumulated other comprehensive income included unrealized losses, net of related tax effects, totaling $159 million, $179 million and $162 million, respectively, associated with commodity derivative contracts. Based upon the market prices at December 31, 2013, we expect to transfer to earnings approximately $23 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 – Derivatives* elsewhere in this Item 7.

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.

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.

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, 2013, 2012 and 2011 are presented below in *Results of Operations - Interest Expense*, and a detailed explanation of accounting for interest rate derivatives appears under *Application of Critical Accounting Policies - Derivatives* 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 - Derivatives* elsewhere in this Item 7.

Results of Operations

General. For the year ended December 31, 2013, Chesapeake had net income of $894 million, or $0.73 per diluted common share, on total revenues of $17.506 billion. This compares to a net loss of $594 million, or $1.46 per diluted common share, on total revenues of $12.316 billion during the year ended December 31, 2012 and 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. The year ended December 31, 2013 includes charges of approximately $546 million for the impairment of buildings, land, drilling rigs, gathering systems and other assets and $248 million related to restructuring and other termination costs incurred in connection with a workforce reduction, executive officer separations and other employee terminations. The charges reflect actions taken as a result of the company-wide review of our operations, assets and organizational structure in the second half of 2013. Certain other actions we expect to take in the future to further our strategic priorities of reducing financial leverage and complexity could negatively impact our future results of operations and/or liquidity. Going forward, we expect to incur further cash and noncash charges, including but not limited to impairments of fixed assets, lease termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity. The net loss in 2012 was 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 2013, natural gas, oil and NGL sales were $7.052 billion compared to $6.278 billion in 2012 and $6.024 billion in 2011. In 2013, Chesapeake produced and sold 244 mmboe for $6.923 billion at a weighted average price of $28.33 per boe, compared to 237 mmboe produced and sold in 2012 for $5.359 billion at a weighted average price of $22.61 per boe and 199 mmboe produced and sold in 2011 for $5.259 billion at a weighted average price of $26.42 per boe. The increase in the price received per boe in 2013 compared to 2012 resulted in an increase in revenues of $1.397 billion, and increased sales volumes resulted in a $167 million increase in revenues, for a total increase in revenues of $1.564 billion.

For 2013, our average price received per mcf of natural gas of $2.22 compared to $1.77 in 2012 and $3.12 in 2011 (excluding the effect of derivatives). Oil prices received per barrel (excluding the effect of derivatives) were $95.17, $90.49 and $89.80 in 2013, 2012 and 2011, respectively. NGL prices realized per barrel (excluding the effect of derivatives) were $27.87, $29.89 and $40.96 in 2013, 2012 and 2011, respectively. In 2013, realized prices for natural gas were negatively affected by higher year-over-year natural gas gathering and transportation costs, primarily as a result of construction of midstream systems being undertaken in certain of our less mature operating areas and a fee associated with a production shortfall below the minimum volume commitment under our Barnett gathering agreement. For 2014, we expect that we will continue to see increased gathering and transportation costs and those increases are reflected in our natural gas price differential forecast for 2014.

Gains and losses from our natural gas, oil and NGL derivatives resulted in a net increase in natural gas, oil and NGL revenues of $129 million, $919 million and $765 million in 2013, 2012 and 2011, respectively. See Item 7A of this report for a complete listing of all of our derivative instruments as of December 31, 2013.

A change in natural gas, oil and NGL prices has a significant impact on our revenues and cash flows. Assuming our 2013 production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2013 revenues and cash flows of approximately $109 million and $107 million, respectively, and an increase or decrease of $1.00 per barrel of liquids sold would result in an increase or decrease in 2013 revenues and cash flows of approximately $62 million and $60 million, respectively, without considering the effect of derivatives.

Our company-wide reorganization in the 2013 second half resulted in two operating divisions replacing the four operating divisions we previously reported. 2012 and 2011 have been revised to reflect our current organization. The following tables show our production and average sales prices received by operating division for 2013, 2012 and 2011:

2013

	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	692.9	2.09	37.6	95.57	16.7	26.32	169.7	69	32.30
Northern[c]	401.7	2.44	3.5	90.82	4.2	33.95	74.7	31	19.28
Total[d]	1,094.6	2.22	41.1	95.17	20.9	27.87	244.4	100%	28.33

2012

	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	868.0	1.68	30.3	90.78	15.8	28.78	190.8	81	24.43
Northern[c]	260.8	2.10	1.0	81.60	1.8	39.73	46.2	19	15.11
Total[d]	1,128.8	1.77	31.3	90.49	17.6	29.89	237.0	100%	22.61

2011

	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	867.8	3.06	16.4	90.00	13.5	39.62	174.5	88	26.76
Northern[c]	136.3	3.48	0.6	83.60	1.2	55.34	24.5	12	24.03
Total[d]	1,004.1	3.12	17.0	89.80	14.7	40.96	199.0	100%	26.42

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

(b) Our Southern Division includes the Eagle Ford, Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime unconventional liquids plays and the Haynesville/Bossier and Barnett unconventional natural gas shale plays. The Eagle Ford Shale accounted for approximately 19% of our estimated proved reserves by volume as of December 31, 2013. Production for the Eagle Ford Shale for 2013, 2012 and 2011 was 31.7 mmboe, 17.8 mmboe and 3.5 mmboe, respectively. The Barnett Shale accounted for approximately 16% of our estimated proved reserves by volume as of December 31, 2013. Production for the Barnett Shale for 2013, 2012 and 2011 was 28.9 mmboe, 30.3 mmboe and 23.9 mmboe, respectively. Our gathering agreements for Barnett and Haynesville require us to pay the service provider a fee for any production shortfall below certain annual minimum gathering volume commitments. These fees amounted to $0.03 per mcf in 2013, and we anticipate incurring shortfall fees in 2014 based on current production estimates.

(c) Our Northern Division includes the Utica and Niobrara unconventional liquids plays and the Marcellus unconventional natural gas play. The Marcellus Shale accounted for approximately 25% of our estimated proved reserves by volume as of December 31, 2013. Production for the Marcellus Shale for 2013, 2012 and 2011 was 62.9 mmboe, 40.5 mmboe and 20.2 mmboe, respectively.

(d) 2013, 2012 and 2011 production levels reflect the impact of various asset sales and joint ventures. See Note 12 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 and joint ventures.

Our average daily production of 670 mboe for 2013 consisted of approximately 3.0 bcf of natural gas (75% on an oil equivalent basis), approximately 169,800 bbls of liquids, consisting of approximately 112,600 bbls of oil (17% on an oil equivalent basis) and approximately 57,200 bbls of NGL (8% on an oil equivalent basis). Our year-over-year growth rate of oil production was 32% and our year-over-year growth rate of NGL production was 19%. Natural gas production declined 3% year over year primarily as a result of asset sales.

Excluding the impact of derivatives, our percentage of revenues from natural gas, oil and NGL is shown in the following table.

	2013	2012	2011
Natural gas	36%	37%	60%
Oil	56%	53%	29%
NGL	8%	10%	11%
Total	100%	100%	100%

Marketing, Gathering and Compression Sales and Expenses. Marketing, gathering and compression revenues and expenses consist of third-party revenues and expenses related to our marketing, gathering and compression operations and excludes depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See *Depreciation and Amortization of Other Assets* below for the depreciation and amortization recorded on our marketing, gathering and compression assets. Chesapeake recognized $9.559 billion in marketing, gathering and compression revenues in 2013 with corresponding expenses of $9.461 billion, for a net margin before depreciation of $98 million. This compares to revenues of $5.431 billion and $5.090 billion, expenses of $5.312 billion and $4.967 billion and a net margin before depreciation of $119 million and $123 million in 2012 and 2011, respectively. Our revenues and operating expenses from our marketing business increased substantially in 2013 compared to 2012 and 2011. In 2013, we marketed significantly more oil and NGL from both Chesapeake-operated wells and for third parties while our marketing of natural gas was virtually unchanged. Due to the relative high prices of oil and NGL compared to natural gas, our revenues and expenses increased substantially. In addition, we entered into a variety of purchase and sales contracts with third parties for various commercial purposes, including credit risk mitigation and to help meet certain of our pipeline delivery commitments. These transactions also increased our marketing revenues and operating expenses. In addition, compression services increased in 2013 compared to 2012 and 2011, offset by the loss of activity from the sale of substantially all of our gathering business and most of our gathering assets in the 2012 and 2013. Our gathering business provided approximately $16 million, $51 million and $44 million of the total marketing, gathering and compression net margin, or 16%, 43% and 36%, in 2013, 2012 and 2011, respectively.

Oilfield Services Revenues and Expenses. Oilfield services consists of third-party revenues and expenses related to our oilfield services operations and excludes depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See *Depreciation and Amortization of Other Assets* below for the depreciation and amortization recorded on our oilfield services assets. Chesapeake recognized $895 million in oilfield services revenues in 2013 with corresponding expenses of $736 million, for a net margin before depreciation of $159 million. This compares to revenues of $607 million and $521 million, expenses of $465 million and $402 million and a net margin before depreciation of $142 million and $119 million in 2012 and 2011, respectively. Oilfield services revenues and expenses increased from 2011 to 2013, primarily as a result of the increase in third-party utilization of our oilfield services.

Natural Gas, Oil and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $1.159 billion in 2013, compared to $1.304 billion in 2012 and $1.073 billion in 2011. On a unit-of-production basis, production expenses were $4.74 per boe in 2013 compared to $5.50 and $5.39 per boe in 2012 and 2011, respectively. The per unit expense decrease in 2013 was primarily the result of a general improvement in operating efficiencies across most of our operating areas as well as lower saltwater disposal costs and the divestiture in 2012 of our Permian Basin assets, which had comparatively high operating costs per unit of production. Production expenses in 2013, 2012 and 2011 included approximately $170 million, $220 million and $234 million, or $0.70, $0.93 and $1.18 per boe, respectively, associated with VPP production volumes. We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease in addition to the general improvement in operating efficiencies noted above.

The following table shows our production expenses by operating division and our ad valorem tax expenses for 2013, 2012 and 2011:

	2013		2012		2011	
	Production Expenses	$/boe	Production Expenses	$/boe	Production Expenses	$/boe
	($ in millions, except per unit)					
Southern	$ 925	5.46	$ 1,087	5.70	$ 875	5.01
Northern	164	2.19	143	3.10	136	5.57
	1,089	4.46	1,230	5.19	1,011	5.08
Ad valorem tax	70	0.28	74	0.31	62	0.31
Total	$ 1,159	4.74	$ 1,304	5.50	$ 1,073	5.39

Production Taxes. Production taxes were $229 million in 2013 compared to $188 million in 2012 and $192 million in 2011. On a unit-of-production basis, production taxes were $0.94 per boe in 2013 compared to $0.79 per boe in 2012 and $0.96 per boe in 2011. 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 $41 million increase in production taxes in 2013 was primarily due to the increase in the unhedged price of our production from $22.61 per boe to $28.33 per boe. Production taxes in 2013, 2012 and 2011 included approximately $21 million, $20 million and $34 million, respectively, or $0.08, $0.08 and $0.17 per boe, respectively, associated with VPP production volumes.

General and Administrative Expenses. General and administrative expenses were $457 million in 2013, $535 million in 2012 and $548 million in 2011, or $1.86, $2.26 and $2.75 per boe, respectively. The absolute and per unit expense decrease in 2013 was primarily due to our efforts to reduce our cost structure and increased emphasis on operational efficiencies, partially offset by an increase in legal expenses relating to various corporate matters. In addition, we anticipate the workforce reduction described below will result in future cost savings and help the Company demonstrate more profitable and efficient growth. Included in general and administrative expenses is stock-based compensation of $60 million in 2013, $71 million in 2012 and $92 million in 2011. See Note 9 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our stock-based compensation.

Chesapeake follows the full cost method of accounting under which all costs associated with natural gas and oil property acquisition, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with acquisition of leasehold and drilling and completion activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $317 million, $434 million and $432 million of internal costs in 2013, 2012 and 2011, respectively, directly related to our natural gas and oil property acquisition and drilling and completion efforts. The decrease was primarily due to our cost structure initiatives and increased emphasis on operational efficiencies in addition to a substantial decrease in our acquisition of unproved properties and lower drilling and completion expenditures.

Restructuring and Other Termination Costs. We recorded $248 million and $7 million of restructuring and other termination costs in 2013 and 2012, respectively. The 2013 amount primarily related to workforce reductions, senior management separations and our voluntary separation plan. The 2012 amount related to other termination benefits. The Company committed to a workforce reduction plan in September 2013 that resulted in a reduction of approximately 900 employees. In connection with the workforce reduction plan, we incurred a total charge of $66 million. The acceleration of vesting of stock-based compensation accounted for approximately $45 million of this expense. We also incurred charges of approximately $182 million in 2013 related to the separation from the Company of certain other employees, including approximately $107 million related to our former CEO and other executive officers that were outside the workforce reduction plan. See Note 17 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Natural Gas, Oil and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas, oil and NGL properties was $2.589 billion, $2.507 billion and $1.632 billion in 2013, 2012 and 2011, respectively. The $82 million and $875 million increases in 2013 and 2012 are primarily the result of 3% and 19% increases in production in 2013 and 2012, respectively, the 2012 decrease in the 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 boe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $10.59, $10.58 and $8.20 in 2013, 2012 and 2011, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $314 million in 2013, compared to $304 million in 2012 and $291 million in 2011. Depreciation and amortization of other assets was $1.28, $1.28 and $1.46 per boe in 2013, 2012 and 2011, respectively. The increase in 2013 is primarily due to increases in depreciation resulting from additions to our hydraulic fracturing equipment during 2013 compared to 2012 and 2011, partially offset by significant decreases in depreciation for natural gas gathering assets, most of which were sold in 2012 and 2013. See Note 15 of the notes to our consolidated financial statements included in Item 8 of this report for information regarding these sales.

Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. To the extent company-owned oilfield services equipment is used to drill and complete our wells, a substantial portion of the depreciation (i.e., the portion related to our utilization of the equipment) is capitalized in natural gas and oil properties as drilling and completion costs. The following table shows depreciation expense by asset class for 2013, 2012 and 2011 and the estimated useful lives of these assets.

	Years Ended December 31,			Estimated Useful Life
	2013	2012	2011	
	($ in millions)			(in years)
Oilfield services equipment[a]	$ 122	$ 61	$ 52	3 - 15
Natural gas gathering systems and treating plants[b]	13	46	58	20
Buildings and improvements	47	42	34	10 - 39
Natural gas compressors[b]	35	26	18	3 - 20
Computers and office equipment	44	45	40	3 - 7
Vehicles	38	52	46	0 - 7
Other	15	32	43	2 - 20
Total depreciation and amortization of other assets	$ 314	$ 304	$ 291	

(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 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 natural gas and oil derivative instruments designated as cash flow hedges. See Note 16 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.

Impairments of Fixed Assets and Other. In 2013, 2012 and 2011, we recognized $546 million, $340 million and $46 million, respectively, of impairment losses and other charges primarily related to buildings, land, gathering systems and drilling rigs. See Note 16 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our impairments of fixed assets and other.

Net Gains on Sales of Fixed Assets. In 2013, net gains on sales of fixed assets were $302 million compared to net gains of $267 million and $437 million in 2012 and 2011, respectively, primarily related to gathering systems sold. See Note 15 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our net gains on sales of fixed assets.

Interest Expense. Interest expense was $227 million in 2013 compared to $77 million in 2012 and $44 million in 2011 as follows:

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
Interest expense on senior notes	$ 740	$ 732	$ 653
Interest expense on credit facilities	38	70	70
Interest expense on term loans	116	173	—
Realized (gains) losses on interest rate derivatives[a]	(9)	(1)	7
Unrealized (gains) losses on interest rate derivatives[b]	67	(6)	7
Amortization of loan discount, issuance costs and other	91	89	39
Capitalized interest	(816)	(980)	(732)
Total interest expense	$ 227	$ 77	$ 44
Average senior notes borrowings	10,991	10,487	9,373
Average term loan borrowings	2,000	2,096	—
Average credit facilities borrowings	678	2,517	2,830

(a) Includes settlements related to the current period interest accrual and the effect of gains/losses on early terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item.

(b) Includes changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized gains/ losses during the period.

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.65 per boe in 2013 compared to $0.35 per boe in 2012 and $0.18 per boe in 2011. The increase in 2013 interest expense is primarily due to a decrease in the amount of interest capitalized as a result of a lower average balance of unevaluated natural gas and oil properties, the primary asset on which interest is capitalized.

Earnings (Losses) on Investments. Losses on investments were $226 million in 2013, compared to losses of $103 million in 2012 and earnings of $156 million in 2011. The 2013 and 2012 losses primarily related to our equity in the net loss of FTS International, Inc. (FTS). The 2011 earnings primarily related to our equity in the net income of ACMP. See Note 13 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our investments.

Gains (Losses) on Sales of Investments. We recorded losses on sales of investments of $7 million in 2013 and gains on sales of investments of $1.092 billion in 2012. In 2013, we sold all of our shares of Clean Energy Fuels Corp. (Clean Energy) for cash proceeds of $13 million. We also sold our $100 million investment in Clean Energy convertible notes for cash proceeds of $85 million. We recorded a $15 million loss related to the sale of the Clean Energy convertible notes and a $3 million gain related to the sale of the Clean Energy common stock. In addition, in 2013 we sold a $1 million equity investment for cash proceeds of $6 million and recorded a $5 million gain. In 2012, we sold all of our common and subordinated units representing limited partner interests in ACMP and all of our limited liability company interests in the sole member of its general partner for cash proceeds of $2.0 billion. We recorded a $1.032 billion pre-tax 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 of Debt and Extinguishment of Other Financing. We recorded losses on purchases of debt and extinguishment of other financing of $193 million in 2013, $200 million in 2012 and $176 million in 2011. In 2013, we terminated the financing master lease agreement on our real estate surface properties in the Fort Worth, Texas area for $258 million and recorded a loss of approximately $123 million associated with the extinguishment. Also, in

2013, we completed tender offers to purchase $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million. We recorded a loss of approximately $37 million associated with the tender offers, including $32 million in premiums and $5 million of unamortized deferred charges. In addition, we redeemed $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 at par pursuant to a notice of special early redemption. We recorded a loss of approximately $33 million associated with the redemption, including $19 million of unamortized deferred charges and $14 million of discount.

In 2012, we used proceeds from asset sales and our November 2012 term loan to fully repay our May 2012 term loans. We recorded $200 million of losses associated with the repayment, including $86 million of deferred charges and $114 million of debt discount.

In 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.

Other Income. Other income was $26 million, $8 million and $23 million in 2013, 2012 and 2011, respectively. The 2013 other income consisted of $5 million of interest income and $21 million of miscellaneous income. 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.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $548 million in 2013 compared to an income tax benefit of $380 million in 2012 and income tax expense of $1.123 billion in 2011. Our effective income tax rate was 38% in 2013 and 39% in both 2012 and 2011. 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. Chesapeake recorded net income attributable to noncontrolling interests of $170 million, $175 million and $15 million in 2013, 2012 and 2011, respectively. Net income attributable to noncontrolling interests is primarily driven by the dividends paid on our CHK Utica and CHK C-T preferred stock in addition to income or loss related to the Chesapeake Granite Wash Trust. See Note 8 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of these entities.

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 three policies we consider to be the most significant are discussed below. The Company's management has discussed each critical accounting policy with the Audit Committee of the Company's Board of Directors.

The selection and application of accounting policies are an important process that changes as our business changes and as accounting rules are developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment in 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 capitalize 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 differ from those of companies that apply the successful efforts method since we generally reflect a higher level of capitalized costs as well as a higher natural gas and oil depreciation, depletion and amortization rate, and we do 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.

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 applicable 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. 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 derivative 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 *Derivative Activities* above and Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* for additional information regarding our derivative 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 counterparty valuations 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, we net the value of our 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, 2013, 2012 and 2011, the fair value of our derivatives were liabilities of $649 million, $979 million and $1.719 billion, respectively.

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 net operating loss carryforwards prior to their expiration, we may be required to provide a valuation allowance against our deferred tax assets. As of December 31, 2013 and 2012, we had deferred tax assets of $1.621 billion and $1.726 billion, respectively, upon which we had a valuation allowance of $148 million and $160 million, respectively, for certain state net operating losses that we have concluded are not more likely than not to be utilized prior to expiration.

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

Disclosures About Effects of Transactions with Related Parties

Former Chief Executive Officer

On April 1, 2013, Aubrey K. McClendon, the co-founder of the Company, ceased serving as President and CEO and as a director of the Company pursuant to his agreement with the Board of Directors announced on January 29, 2013. Since Chesapeake was founded in 1989, Mr. McClendon and his affiliates have acquired working interests in virtually all of our natural gas and oil properties by participating in our drilling activities under the terms of Mr. McClendon’s employment agreements and, since 2005, the Founder Well Participation Program (FWPP). The Company is reimbursed for costs associated with leasehold acquired under the FWPP, and well costs are charged to FWPP interests based on percentage ownership. On April 30, 2012, the Company's Board of Directors and Mr. McClendon agreed to terminate the FWPP 18 months before the end of the 10-year term approved by our shareholders in June 2005. Mr. McClendon has elected to participate in the FWPP through the expiration of the FWPP on June 30, 2014 at the maximum 2.5% working interest permitted, the same participation percentage that Mr. McClendon has elected every year since 2004. The Compensation Committee of the Board of Directors, which administers and interprets the FWPP, is reviewing with the assistance of independent counsel the prior administration of the plan. As of December 31, 2013 and 2012, we had accrued accounts receivable from Mr. McClendon of $62 million and $23 million, respectively, representing FWPP joint interest billings. 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 percentages. These interests were acquired through the FWPP.

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 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. The incentive award was subject to a clawback provision 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 recognized 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 incentive award clawback did not apply to Mr. McClendon’s termination in 2013. See Note 17 of the notes to our consolidated financial statements included in Item 8 of this report for additional information on the terms of Mr. McClendon’s separation from the Company.

On July 26, 2013, the Company and Mr. McClendon rescinded the December 2008 sale of an antique map collection pursuant to the terms of a settlement agreement terminating pending shareholder litigation that was approved by the District Court of Oklahoma County, Oklahoma on January 30, 2012 and affirmed on appeal. The Company returned the subject maps to Mr. McClendon, and Mr. McClendon paid the Company $12 million plus interest.

Equity Method Investees

Other than Mr. McClendon, only our equity method investees were considered related parties. During 2013, 2012 and 2011, we had the following related party transactions with our equity method investees.

	Years Ended December 31,		
	2013	2012	2011
		($ in millions)	
Purchases[(a)]	$ —	$ 73	$ —
Sales[(b)]	$ 666	$ 392	$ 171
Services[(c)]	$ 397	$ 480	$ 369

(a) Purchase of equipment from FTS.

(b) In 2013, 2012 and 2011, Chesapeake sold produced gas to our 30%-owned investee, Twin Eagle Resource Management LLC.

(c) Hydraulic fracturing and other services provided to us by FTS in the ordinary course of business. As well operators, we are reimbursed by other working interest owners through the joint interest billing process for their proportionate share of these costs.

The table below shows the total related party amounts due from and due to our equity method investees.

	December 31,		
	2013	2012	2011
		($ in millions)	
Amounts due from equity method investment related parties	$ 47	$ 67	$ 29
Amounts due to equity method investment related parties	$ 1	$ 42	$ 115

Recently Issued Accounting Standards

Recently Adopted Accounting Standards

In February 2012, the Financial Accounting Standards Board (FASB) issued guidance changing the presentation requirements of significant reclassifications out of accumulated other comprehensive income in their entirety and their corresponding effect on net income. We adopted this standard in the first quarter of 2013 and it did not have a material impact on our financial statements.

In December 2011 and January 2013, the FASB issued guidance amending and expanding disclosure requirements about offsetting and related arrangements associated with derivatives. We adopted this standard in the first quarter of 2013 and it did not have a material impact on our financial statements.

Recently Issued Accounting Standards

To reduce diversity in practice related to the presentation of unrecognized tax benefits, in July 2013 the FASB issued guidance requiring the presentation of an unrecognized tax benefit in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward. This net presentation is required unless a net operating loss carryforward, a similar tax loss or a tax credit carryforward is not available at the reporting date or the tax law of the jurisdiction does not require, and the entity does not intend to use, the deferred tax asset to settle any additional income tax that would result from the disallowance of the unrecognized tax benefit. The guidance will be effective on January 1, 2014; retrospective application and early adoption are permitted, but not required. Because we have historically presented unrecognized tax benefits net of net operating loss carryforwards, similar tax losses or tax credit carryforwards, this standard will not impact our consolidated financial statements.

In February 2013, the FASB issued guidance on the recognition, measurement and disclosure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. We will adopt this standard effective January 1, 2014. We do not expect the adoption to have a material impact on our consolidated financial statements.

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 (the "Exchange Act"). Forward-looking statements give our current expectations or forecasts of future events. They include 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, estimates of future drilling and completion and other 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, operating and capital efficiencies, business strategy and other plans and objectives for future operations. Our ability to generate sufficient operating cash flow to fund future capital expenditures 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. Further, asset dispositions we are evaluating as we focus on our strategic priorities are subject to market conditions and other factors beyond our control. Our plans to reduce financial leverage and complexity may take longer to implement if such dispositions are delayed or do not occur as expected. 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;
- the availability of capital on an economic basis to fund reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- declines in the prices of natural gas and oil potentially resulting in a write-down of our asset carrying values;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- leasehold terms expiring before production can be established;
- commodity derivative activities resulting in lower prices realized on natural gas, oil and NGL sales;
- the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations;
- charges incurred in connection with actions to reduce financial leverage and complexity;
- competition in the oil and gas exploration and production industry;
- drilling and operating risks, including potential environmental liabilities;
- our need to acquire adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing, air emissions and endangered species;
- a deterioration in general economic, business or industry conditions;
- oilfield services shortages, gathering system and transportation capacity constraints and various transportation interruptions that could adversely affect our revenues and cash flow;
- adverse developments or losses from pending or future litigation and regulatory investigations;
- cyber attacks adversely impacting our operations; and
- an interruption in operations at our headquarters due to a catastrophic event.

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 except as required by applicable law. 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 our exposure to adverse price 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 share of 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, collars, 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 price risk we hedge. Swaps are used when the price level is acceptable. We have also sold calls, taking advantage of market price volatility. We do this when we would be satisfied with 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 and 2013, 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. In some cases, we deferred the payment of the premium on these trades to the related month of production. 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 statements of cash flows.

We determine the volume potentially subject to derivative contracts by reviewing our overall 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 enter into derivative contracts for more volumes than our forecasted production, 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 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 negotiating a cash settlement with our counterparty, restructuring the position or 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 recognized 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 counterparty valuations 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 multi-counterparty 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 18 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, 2013, 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.
- *Collars:* These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option.
- *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 in exchange for a premium that allows a counterparty, on a specific date, to enter into a 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, 2013, we had the following open natural gas and oil derivative instruments:

		Weighted Average Price				Fair Value
	Volume	**Fixed**	**Call**	**Put**	**Differential**	**Asset (Liability)**
	(tbtu)	**($ per mmbtu)**				**($ in millions)**
Natural Gas:						
Swaps:						
Short-term	448	4.15	—	—	—	$ (23)
3-Way Collars:						
Short-term	196	—	4.38	3.58 / 4.13	—	(9)
Long-term	92	—	4.45	3.38 / 4.24	—	2
Call Options (sold):						
Short-term	330	—	6.43	—	—	(4)
Long-term	619	—	7.34	—	—	(28)
Call Options (bought)[a]:						
Long-term	(330)	—	6.43	—	—	(36)
Short-term	(426)	—	6.17	—	—	(142)
Swaptions:						
Short-term	12	4.80	—	—	—	—
Basis Protection Swaps:						
Short-term	28	—	—	—	(0.32)	1
Long-term	40	—	—	—	(0.48)	2
Total Natural Gas						$ (237)

		Weighted Average Price				Fair Value
	Volume	Fixed	Call	Put	Differential	Asset (Liability)
	(mmbbl)		($ per bbl)			($ in millions)
Oil:						
Swaps:						
Short-term	24.6	93.92	—	—	—	$ (50)
Long-term	0.7	89.47	—	—	—	—
Call Options (sold):						
Short-term	13.4	—	96.11	—	—	(66)
Long-term	48.9	—	100.26	—	—	(180)
Call Options (bought)[(b)]:						
Short-term	(10.9)	—	98.97	—	—	(14)
Long-term	(8.9)	—	113.54	—	—	(5)
Basis Protection Swaps:						
Short-term	0.4	—	—	—	6.00	1
Total Oil						$ (314)
Total Natural Gas and Oil						$ (551)

(a) Included in the fair value are deferred premiums of $40 million, $82 million and $85 million which will be included in natural gas, oil and NGL sales as realized gains (losses) in 2014, 2015 and 2016, respectively.

(b) Included in the fair value are deferred premiums of $46 million and $13 million which will be included in natural gas, oil and NGL sales as realized gains (losses) in 2014 and 2015, respectively.

In addition to the open derivative positions disclosed above, as of December 31, 2013, we had $58 million of net derivative gains related to settled contracts for future production periods that will be recorded within natural gas, oil and NGL sales as realized gains (losses) on derivatives as they are transferred from either accumulated other comprehensive income or unrealized gains (losses) on derivatives in the month of related production based on the terms specified in the original contract as noted below.

	December 31, 2013
	($ in millions)
2014	$ (174)
2015	216
2016 – 2022	16
Total	$ 58

The table below reconciles the changes in fair value of our natural gas and oil derivatives during each of the years ended December 31, 2013, 2012 and 2011. Of the $551 million fair value liability as of December 31, 2013, $200 million related to contracts maturing in the next 12 months and $351 million related to contracts maturing after 12 months. All open derivative instruments as of December 31, 2013 are expected to mature by December 31, 2022.

	December 31, 2013
	($ in millions)
Fair value of contracts outstanding, as of January 1	$ (924)
Change in fair value of contracts	218
Fair value of new contracts when entered into	(48)
Contracts realized or otherwise settled	203
Fair value of contracts when closed	—
Fair value of contracts outstanding, as of December 31	$ (551)

The change in natural gas and oil prices during the year ended December 31, 2013 decreased the liability related to our derivative instruments by $218 million. This unrealized gain is recorded in natural gas, oil and NGL sales. We entered into new contracts which were in a liability position of $48 million and we settled contracts in 2013 that were in a liability position for $203 million. The realized losses will be recorded in natural gas, oil and NGL sales in the month of related production.

Interest Rate Derivatives

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

	Years of Maturity						
	2014	2015	2016	2017	2018	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[(a)]	$ —	$ 1,661	$ 500	$ 2,302	$ 1,112	$ 5,250	$ 10,825
Average interest rate	—%	7.89%	3.25%	4.42%	5.66%	6.20%	5.89%
Debt – variable rate[(b)]	$ —	$ —	$ 405	$ 2,000	$ —	$ —	$ 2,405
Average interest rate	—%	—%	2.92%	5.75%	—%	—%	5.27%

(a) This amount does not include the discount included in debt of $324 million and interest rate derivatives of $13 million.

(b) This amount does not include the discount included in debt of $33 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.

We enter into interest rate derivatives, including 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 and 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 facility borrowings. As of December 31, 2013, the following interest rate derivatives were outstanding:

	Notional Amount	Weighted Average Rate: Fixed	Weighted Average Rate: Floating[(a)]	Fair Value Hedge	Fair Value Asset (Liability)
	($ in millions)				($ in millions)
Fixed to Floating:					
Swaps					
Mature 2020 – 2023	$ 1,200	6.01%	1 – 3 mL 430 bp	No	$ (79)
Floating to Fixed:					
Swaps					
Mature 2014 – 2015	$ 1,050	2.13%	1 – 6 mL	No	(19)
					$ (98)

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

In addition to the open derivative positions disclosed above, as of December 31, 2013, we had $65 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 our senior note liability or within interest expense as unrealized gains (losses) over the remaining seven-year term of our related senior notes.

Realized and unrealized gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations.

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. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €11 million and we pay the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €344 million and we 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 our 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 an asset of $2 million as of December 31, 2013. The euro-denominated debt in long-term debt has been adjusted to $473 million as of December 31, 2013 using an exchange rate of $1.3743 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* (1992) 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, 2013.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

/s/ ROBERT D. LAWLER

Robert D. Lawler
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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, 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 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
February 26, 2014

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2013	2012
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$ 837	$ 287
Restricted cash	75	111
Accounts receivable, net	2,222	2,245
Short-term derivative assets	—	58
Deferred income tax asset	223	90
Other current assets	299	153
Current assets held for sale	—	4
Total Current Assets	3,656	2,948
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full cost accounting:		
Proved natural gas and oil properties ($488 and $488 attributable to our VIE)	56,157	50,172
Unproved properties	12,013	14,755
Oilfield services equipment	2,192	2,130
Other property and equipment	3,203	3,778
Total Property and Equipment, at Cost	73,565	70,835
Less: accumulated depreciation, depletion and amortization (($168) and ($58) attributable to our VIE)	(37,161)	(34,302)
Property and equipment held for sale, net	730	634
Total Property and Equipment, Net	37,134	37,167
LONG-TERM ASSETS:		
Investments	477	728
Long-term derivative assets	4	2
Other long-term assets	511	766
TOTAL ASSETS	$ 41,782	$ 41,611

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS – (Continued)

	December 31, 2013	December 31, 2012
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 1,596	$ 1,710
Short-term derivative liabilities ($5 and $4 attributable to our VIE)	208	105
Accrued interest	200	226
Current maturities of long-term debt, net	—	463
Other current liabilities ($22 and $21 attributable to our VIE)	3,511	3,741
Current liabilities held for sale	—	21
Total Current Liabilities	5,515	6,266
LONG-TERM LIABILITIES:		
Long-term debt, net	12,886	12,157
Deferred income tax liabilities	3,407	2,807
Long-term derivative liabilities ($0 and $3 attributable to our VIE)	445	934
Asset retirement obligations	405	375
Other long-term liabilities	984	1,176
Total Long-Term Liabilities	18,127	17,449
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: 666,192,371 and 666,467,664 shares issued	7	7
Paid-in capital	12,446	12,293
Retained earnings	688	437
Accumulated other comprehensive loss	(162)	(182)
Less: treasury stock, at cost; 2,002,029 and 2,147,724 common shares	(46)	(48)
Total Chesapeake Stockholders' Equity	15,995	15,569
Noncontrolling interests	2,145	2,327
Total Equity	18,140	17,896
TOTAL LIABILITIES AND EQUITY	$ 41,782	$ 41,611

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,		
	2013	2012	2011
	($ in millions except per share data)		
REVENUES:			
Natural gas, oil and NGL	$ 7,052	$ 6,278	$ 6,024
Marketing, gathering and compression	9,559	5,431	5,090
Oilfield services	895	607	521
Total Revenues	17,506	12,316	11,635
OPERATING EXPENSES:			
Natural gas, oil and NGL production	1,159	1,304	1,073
Production taxes	229	188	192
Marketing, gathering and compression	9,461	5,312	4,967
Oilfield services	736	465	402
General and administrative	457	535	548
Restructuring and other termination costs	248	7	—
Natural gas, oil and NGL depreciation, depletion and amortization	2,589	2,507	1,632
Depreciation and amortization of other assets	314	304	291
Impairment of natural gas and oil properties	—	3,315	—
Impairments of fixed assets and other	546	340	46
Net gains on sales of fixed assets	(302)	(267)	(437)
Total Operating Expenses	15,437	14,010	8,714
INCOME (LOSS) FROM OPERATIONS	2,069	(1,694)	2,921
OTHER INCOME (EXPENSE):			
Interest expense	(227)	(77)	(44)
Earnings (losses) on investments	(226)	(103)	156
Gains (losses) on sales of investments	(7)	1,092	—
Losses on purchases of debt and extinguishment of other financing	(193)	(200)	(176)
Other income	26	8	23
Total Other Income (Expense)	(627)	720	(41)
INCOME (LOSS) BEFORE INCOME TAXES	1,442	(974)	2,880
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	22	47	13
Deferred income taxes	526	(427)	1,110
Total Income Tax Expense (Benefit)	548	(380)	1,123
NET INCOME (LOSS)	894	(594)	1,757
Net income attributable to noncontrolling interests	(170)	(175)	(15)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	724	(769)	1,742
Preferred stock dividends	(171)	(171)	(172)
Premium on purchase of preferred shares of a subsidiary	(69)	—	—
Earnings allocated to participating securities	(10)	—	—
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 474	$ (940)	$ 1,570
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ 0.73	$ (1.46)	$ 2.47
Diluted	$ 0.73	$ (1.46)	$ 2.32
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.35	$ 0.35	$ 0.3375
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	653	643	637
Diluted	653	643	752

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31, 2013	2012	2011
		($ in millions)	
NET INCOME (LOSS)	$ 894	$ (594)	$ 1,757
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Unrealized gain on derivative instruments, net of income tax expense of $1 million, $4 million and $137 million	2	6	224
Reclassification of (gain) loss on settled derivative instruments, net of income tax expense (benefit) of $12 million, ($10) million and ($139) million	20	(17)	(225)
Ineffective portion of derivatives designated as cash flow hedges, net of income tax expense of $0, $0 and $3 million	—	—	4
Unrealized loss on investments, net of income tax benefit of ($4) million, ($4) million and ($1) million	(6)	(5)	(1)
Reclassification of (gain) loss on investment, net of income tax expense (benefit) of $3 million, $0 and $0	4	—	—
Other Comprehensive Income (Loss)	20	(16)	2
COMPREHENSIVE INCOME (LOSS)	914	(610)	1,759
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(170)	(175)	(15)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 744	$ (785)	$ 1,744

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,		
	2013	2012	2011
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ 894	$ (594)	$ 1,757
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	2,903	2,811	1,923
Deferred income tax expense (benefit)	526	(427)	1,110
Derivative gains, net	(71)	(926)	(751)
Cash (payments) receipts on derivative settlements, net	(106)	226	725
Stock-based compensation	98	120	153
Net gains on sales of fixed assets	(302)	(267)	(437)
Impairment of natural gas and oil properties	—	3,315	—
Impairments of fixed assets and other	483	316	46
(Gains) losses on investments	229	164	(41)
(Gains) losses on sales of investments	7	(1,092)	—
Losses on purchases of debt and extinguishment of other financing	40	200	5
Restructuring and other termination costs	175	2	—
Other	80	72	(3)
(Increase) decrease in accounts receivable and other assets	5	(68)	(530)
Increase (decrease) in accounts payable, accrued liabilities and other	(347)	(1,015)	1,946
Net Cash Provided By Operating Activities	4,614	2,837	5,903
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and completion costs	(5,604)	(8,930)	(7,467)
Acquisitions of proved and unproved properties	(1,032)	(3,161)	(4,974)
Proceeds from divestitures of proved and unproved properties	3,467	5,884	7,651
Additions to other property and equipment	(972)	(2,651)	(2,009)
Proceeds from sales of other assets	922	2,492	1,312
Proceeds from (additions to) investments	(44)	(395)	101
Proceeds from sales of investments	115	2,000	—
Acquisition of drilling company	—	—	(339)
(Increase) decrease in restricted cash	177	(222)	(44)
Other	4	(1)	(43)
Net Cash Used In Investing Activities	(2,967)	(4,984)	(5,812)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from credit facilities borrowings	7,669	20,318	15,509
Payments on credit facilities borrowings	(7,682)	(21,650)	(17,466)
Proceeds from issuance of senior notes, net of discount and offering costs	2,274	1,263	1,614
Proceeds from issuance of term loans, net of discount and offering costs	—	5,722	—
Cash paid to purchase debt	(2,141)	(4,000)	(2,015)
Cash paid for common stock dividends	(233)	(227)	(207)
Cash paid for preferred stock dividends	(171)	(171)	(172)
Cash paid on financing derivatives	(91)	(37)	1,043
Cash paid to extinguish other financing	(141)	—	—
Cash paid for prepayment of mortgage	(55)	—	—
Proceeds from sales of noncontrolling interests	6	1,077	1,348
Proceeds from other financings	—	257	300
Cash paid to purchase preferred shares of a subsidiary	(212)	—	—
Distributions to noncontrolling interest owners	(215)	(218)	(9)
Other	(105)	(251)	213
Net Cash Provided By (Used In) Financing Activities	(1,097)	2,083	158
Net increase (decrease) in cash and cash equivalents	550	(64)	249
Cash and cash equivalents, beginning of period	287	351	102
Cash and cash equivalents, end of period	$ 837	$ 287	$ 351

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

Supplemental disclosures to the consolidated statements of cash flows are presented below:

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
SUPPLEMENTAL CASH FLOW INFORMATION:			
Interest, net of capitalized interest	$ (43)	$ —	$ —
Income taxes, net of refunds received	$ 26	$ 44	$ (25)
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Change in accrued drilling and completion costs	$ (63)	$ (75)	$ 176
Change in accrued acquisitions of proved and unproved properties	$ (1)	$ 242	$ 81
Change in accrued additions to other property and equipment	$ (81)	$ (25)	$ 64

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 3,062	$ 3,062	$ 3,065
Conversion of 0,0 and 3,000 shares of preferred stock for common stock	—	—	(3)
Balance, end of period	3,062	3,062	3,062
COMMON STOCK:			
Balance, beginning and end of period	7	7	7
PAID-IN CAPITAL:			
Balance, beginning of period	12,293	12,146	12,194
Stock-based compensation	162	174	171
Conversion of preferred stock for 0, 0 and 111,111 shares of common stock	—	—	3
Purchase of contingent convertible notes	—	—	(123)
Offering/transaction expenses	—	—	(12)
Reduction in tax benefit from stock-based compensation	(13)	(30)	(26)
Dividends on common stock	—	—	(48)
Dividends on preferred stock	—	—	(15)
Exercise of stock options	4	3	2
Balance, end of period	12,446	12,293	12,146
RETAINED EARNINGS:			
Balance, beginning of period	437	1,608	190
Net income (loss) attributable to Chesapeake	724	(769)	1,742
Dividends on common stock	(233)	(231)	(168)
Dividends on preferred stock	(171)	(171)	(156)
Premium on purchase of preferred shares of a subsidiary	(69)	—	—
Balance, end of period	688	437	1,608
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(182)	(166)	(168)
Hedging activity	22	(11)	3
Investment activity	(2)	(5)	(1)
Balance, end of period	(162)	(182)	(166)

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

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
TREASURY STOCK – COMMON:			
Balance, beginning of period	(48)	(33)	(24)
Purchase of 251,403, 652,443 and 425,140 shares for company benefit plans	(6)	(16)	(11)
Release of 397,098, 57,252 and 93,906 shares from company benefit plans	8	1	2
Balance, end of period	(46)	(48)	(33)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	15,995	15,569	16,624
NONCONTROLLING INTERESTS:			
Balance, beginning of period	2,327	1,337	—
Sales of noncontrolling interests	6	1,077	1,340
Net income attributable to noncontrolling interests	170	175	15
Distributions to noncontrolling interest owners	(215)	(218)	(18)
Deconsolidation of investments, net	—	(44)	—
Purchase of preferred shares of a subsidiary	(143)	—	—
Balance, end of period	2,145	2,327	1,337
TOTAL EQUITY	$ 18,140	$ 17,896	$ 17,961

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 acquisition, exploration and development of properties for the production of natural gas, oil and natural gas liquids (NGL) from underground reservoirs. We also own substantial marketing, compression and other oilfield services businesses. Our operations are located onshore in the U.S.

Basis of Presentation

The accompanying consolidated financial statements of Chesapeake are prepared in accordance with accounting principles generally accepted in the United States (U.S. GAAP) and include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake has a controlling financial interest. Intercompany accounts and balances have been eliminated.

Accounting Estimates

The preparation of financial statements in conformity with U.S. GAAP 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 could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. Changes in natural gas, oil or NGL prices could result in actual results differing significantly from our estimates.

Consolidation

Chesapeake consolidates entities in which we have a controlling financial interest. We consolidate subsidiaries in which we hold, 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 has the ability to exercise significant influence through its investment in common stock. 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 13 for further discussion of our investments. Undivided interests in natural gas and oil exploration and production joint ventures are consolidated on a proportionate basis.

Noncontrolling Interests

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

Variable Interest Entities

VIEs are entities that, by design, either (i) lack sufficient equity to permit the entity to finance its activities independently, or (ii) have equity holders that do not have the power to direct the activities of the entity that most significantly impact its economic performance, the obligation to absorb the entity’s losses, or the right to receive the entity’s residual returns. We consolidate a VIE when we are the primary beneficiary, which is the party that has both (i) the power to direct the activities that most significantly impact the VIE’s economic performance and (ii) through its interests in the VIE, the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

Along with a VIE that we consolidate, we also hold a variable interest in another VIE that is not consolidated because we are not the primary beneficiary. We continually monitor both the consolidated and unconsolidated VIEs to determine if any events have occurred that could cause the primary beneficiary to change. See Note 14 for further discussion of VIEs.

Risks and Uncertainties

We have recently conducted a company-wide review of our operations, assets and organizational structure to best position the Company to maximize shareholder value going forward as we focus on our strategic priorities of financial discipline and profitable and efficient growth from captured resources. We intend to apply financial discipline through all aspects of our business, and we believe that the successful execution of this strategy will allow us to better balance capital expenditures with cash flow from operations as well as reduce financial leverage and complexity. While furthering our strategic priorities, certain actions that would reduce financial leverage and complexity could negatively impact our future results of operations and/or liquidity. We expect to incur various cash and noncash charges, including but not limited to impairments of fixed assets, lease termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity.

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). See Note 8 for further discussion of these entities.

Accounts Receivable

Our accounts receivable are primarily from purchasers of natural gas, oil and NGL and from exploration and production companies that own interests in properties we operate. This industry concentration could affect our overall exposure to credit risk, either positively or negatively, because our purchasers 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 2013, 2012 and 2011, we recognized $2 million, a nominal amount and $1 million of bad debt expense related to potentially uncollectible receivables, and we reduced our allowance by $3 million in 2013 as we wrote off specific receivables against our allowance. Accounts receivable as of December 31, 2013 and 2012 are detailed below.

	December 31,	
	2013	2012
	($ in millions)	
Natural gas, oil and NGL sales	$ 1,548	$ 1,457
Joint interest	417	592
Oilfield services	63	24
Related parties[(a)]	62	23
Other	150	168
Allowance for doubtful accounts	(18)	(19)
Total accounts receivable, net	$ 2,222	$ 2,245

(a) See Note 7 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 these activities and do not capitalize any costs related to production, general corporate overhead or similar activities (see *Supplementary Information - Supplemental Disclosures About Natural Gas, Oil and NGL Producing Activities*). 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, 2013 were prepared by independent engineering firms and Chesapeake's internal staff. Approximately 81% of these proved reserves estimates (by volume) as of December 31, 2013 were prepared by independent engineering firms. In addition, our internal engineers review and update our reserves on a quarterly basis.

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 unproved 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. Unproved properties are grouped by major prospect area where individual property costs are not significant. In addition, we analyze our unproved leasehold and transfer to proved 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.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2013 and the year in which the associated costs were incurred.

	Year of Acquisition				
	2013	2012	2011	Prior	Total
	($ in millions)				
Leasehold acquisition cost	$ 229	$ 1,648	$ 2,113	$ 5,066	$ 9,056
Exploration cost	623	341	93	8	1,065
Capitalized interest	667	516	270	439	1,892
Total	$ 1,519	$ 2,505	$ 2,476	$ 5,513	$ 12,013

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 derivatives designated as cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. The ceiling test calculation uses costs as of the end of the applicable quarterly period and the unweighted arithmetic average of natural gas, oil and NGL 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. As of December 31, 2013, none of our open derivative instruments were designated as cash flow hedges. Our natural gas and oil hedging activities are discussed in Note 11.

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 is written off as an expense.

We account for seismic costs as part of our 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 to determine whether impairment has occurred. To the extent that seismic costs cannot be directly associated with specific unproved 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 and hydraulic fracturing equipment, natural gas compressors, buildings and improvements, land, vehicles, office equipment, natural gas and oil gathering systems and treating plants. Substantially all of our natural gas gathering systems and treating plants were sold in 2013 and 2012 as discussed in Note 15. 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 15 for further discussion of our gains and losses on the sales of other property and equipment and a summary of our other property and equipment held for sale as of December 31, 2013. Other property and equipment costs, excluding land, are depreciated on a straight-line basis.

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. During 2013, 2012 and 2011, we determined that certain of our property and equipment was being carried at values that were not recoverable and in excess of fair value. See Note 16 for further discussion of these impairments.

Capitalized Interest

Interest from external borrowings is capitalized on significant projects until the asset is ready for service using the weighted average cost of outstanding borrowings. Capitalized interest is determined by multiplying our weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Capitalized interest is depreciated over the useful lives of the assets in the same manner as the depreciation of the underlying asset.

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.

Our goodwill of $43 million as of December 31, 2013 and 2012 consisted of the excess consideration over the fair value of assets acquired of $28 million in our Bronco Drilling Company acquisition and $15 million in our 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 2013 and 2012. Based on these assessments, no impairment of goodwill was required. Goodwill is included in our oilfield services segment.

Accounts Payable

Included in accounts payable as of December 31, 2013 and 2012 are liabilities of approximately $397 million and $432 million, respectively, representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts.

Debt Issuance and Hedging Facility Costs

Included in other long-term assets are costs associated with the issuance of our senior notes, term loan, revolving bank credit facilities and hedging facility. The remaining unamortized issuance costs as of December 31, 2013 and 2012 totaled $145 million and $182 million, respectively, and are being amortized over the life of the applicable debt or facility using the effective interest method.

Environmental Remediation Costs

Chesapeake records environmental reserves for estimated remediation costs related to existing conditions from past operations when the responsibility to remediate is probable and the costs can be reasonably estimated. Expenditures that create future benefits or contribute to future revenue generation are capitalized.

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 19 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, 2013 and 2012 was $11 million and $9 million, respectively.

Marketing, Gathering and Compression Sales. Chesapeake takes title to the natural gas, oil and NGL it purchases from other interest owners in operated wells at defined delivery points and delivers the product to third parties, at which time revenues are recorded. Chesapeake's results of operations related to its natural gas, oil and NGL 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.* Revenues are generated by drilling oil and natural gas wells for our customers under daywork contracts and recognized for the days completed based on the dayrate specified in each contract. Revenue generated and costs incurred for mobilization services are recognized over the days of actual mobilization.
- *Hydraulic Fracturing.* Revenue is recognized upon the completion of each fracturing stage. Typically one or more fracturing stages per day per active crew is completed 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 fracturing services.
- *Oilfield Rentals*. Oilfield equipment rentals include drill pipe, drill collars, tubing, blowout preventers, and frac and mud tanks, and services include air drilling services and services associated with the transfer of fresh water to the wellsite. Rentals and services are priced by the day or hour based on the type of equipment being rented and the service job performed. Revenue is recognized ratably over the term of the rental.
- *Oilfield Trucking*. Oilfield trucking provides rig relocation and logistics services as well as fluid handling services. Trucks move drilling rigs, crude oil, other fluids and construction materials to and from the wellsites and also transport produced water from the wellsites. These services are priced on a per barrel basis based on mileage and revenue is recognized as services are performed.
- *Other Operations.* A manufacturing subsidiary designs, engineers and fabricates natural gas compressor packages that are purchased primarily by Chesapeake. Compression units are priced based on certain specifications such as horsepower, stages and additional options. Revenue is recognized upon completion and transfer of ownership of the natural gas compression unit.

Fair Value Measurements

Certain financial instruments are reported at fair value on our 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 asset or liability and have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

Derivatives

Derivative instruments are recorded on the consolidated balance sheets as derivative assets or derivative liabilities at fair value, and changes in a derivative’s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying commodity derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. Changes in the fair value of interest rate derivative instruments designated as fair value hedges 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 hedge effectiveness and are recognized currently in earnings.

We have elected not to designate any of our qualifying commodity and interest rate derivatives as cash flow or fair value hedges. Therefore, changes in fair value of these derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are recognized in the consolidated statements of operations within natural gas, oil and NGL sales and interest expense, respectively. 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. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivatives are 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. All of our derivative instruments are subject to master netting arrangements by contract type (i.e., commodity, interest rate and cross currency contracts) which provide for offsetting of asset and liability positions within each contract type, as well as related cash collateral if applicable, by counterparty. Therefore, we net the value of our derivative instruments by contract type with the same counterparty in the accompanying consolidated balance sheets.

We have established the fair value of our derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. 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. 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. See Note 11 for further discussion of our derivative instruments.

Share-Based Compensation

Chesapeake's share-based compensation program consists of restricted stock, stock options and performance share units granted to employees and restricted stock granted to non-employee directors under our Long Term Incentive Plan. We recognize in our financial statements the cost of employee services received in exchange for restricted stock and stock options based on the fair value of the equity instruments as of the grant date. For employees, this value is amortized over the vesting period, which is generally three or four years from the grant date. For directors, although restricted stock grants vest over three years, this value is recognized immediately as there is a non-substantive service condition for vesting. Because performance share units can only be settled in cash, they are classified as a liability in our consolidated financial statements and are measured at fair value as of the grant date and re-measured at fair value at the end of each reporting period. These fair value adjustments are recognized as compensation expense in the consolidated statements of operations.

To the extent compensation cost relates to employees directly involved in the acquisition of natural gas and oil leasehold and 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, based on the employees involved in those activities.

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 tax benefits are classified as operating cash outflows in our consolidated statements of cash flows. See Note 9 for further discussion of share-based compensation.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2012 and 2011 to conform to the presentation used for the 2013 consolidated financial statements.

2. Earnings Per Share

Basic earnings per share (EPS) is calculated using the weighted average number of common shares outstanding during the period and includes the effect of any participating securities as appropriate. Participating securities consist of unvested restricted stock issued to our employees and non-employee directors that provide dividend rights.

Diluted EPS is calculated assuming issuance of common shares for all potentially dilutive securities, provided the effect is not antidilutive. For the years ended December 31, 2013, 2012 and 2011, our contingent convertible senior notes did not have a dilutive effect and therefore were excluded from the calculation of diluted EPS. See Note 3 for further discussion of our contingent convertible senior notes.

For the years ended December 31, 2013 and 2012, our cumulative convertible preferred stock and participating securities and associated adjustments to net income, consisting of dividends on such shares, were excluded from the calculation of diluted EPS, as the effect was antidilutive. The impact of our stock options was immaterial in the calculation of diluted EPS for these two years. The following table sets forth the net income adjustments and shares of common stock related to our outstanding cumulative convertible preferred stock and participating securities in 2013 and 2012:

	Net Income Adjustments ($ in millions)	Shares (in millions)
Year Ended December 31, 2013:		
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	40
5.00% cumulative convertible preferred stock (series 2005B)	$ 10	5
4.50% cumulative convertible preferred stock	$ 12	6
Participating securities	$ 10	5
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
Participating securities	$ —	5

For the year ended December 31, 2011, all outstanding equity securities that were convertible into common stock were included in the calculation of diluted EPS. A reconciliation of basic EPS and diluted EPS for the year ended December 31, 2011 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	
Participating securities	—	9	
Outstanding stock options	—	1	
Diluted EPS	$ 1,742	752	$ 2.32

3. Debt

Our long-term debt consisted of the following as of December 31, 2013 and 2012:

	December 31, 2013	December 31, 2012
	($ in millions)	
Term loan due 2017	$ 2,000	$ 2,000
7.625% senior notes due 2013	—	464
9.5% senior notes due 2015	1,265	1,265
3.25% senior notes due 2016	500	—
6.25% euro-denominated senior notes due 2017[(a)]	473	454
6.5% senior notes due 2017	660	660
6.875% senior notes due 2018	97	474
7.25% senior notes due 2018	669	669
6.625% senior notes due 2019[(b)]	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
5.375% senior notes due 2021	700	—
5.75% senior notes due 2023	1,100	—
2.75% contingent convertible senior notes due 2035[(c)]	396	396
2.5% contingent convertible senior notes due 2037[(c)]	1,168	1,168
2.25% contingent convertible senior notes due 2038[(c)]	347	347
Corporate revolving bank credit facility	—	—
Oilfield services revolving bank credit facility	405	418
Discount on senior notes and term loan[(d)]	(357)	(465)
Interest rate derivatives[(e)]	13	20
Total debt, net	12,886	12,620
Less current maturities of long-term debt, net[(f)]	—	(463)
Total long-term debt, net	$ 12,886	$ 12,157

(a) The principal amount shown is based on the exchange rate of $1.3743 to €1.00 and $1.3193 to €1.00 as of December 31, 2013 and 2012, respectively. See Note 11 for information on our related foreign currency derivatives.

(b) 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.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarterly. In the fourth quarter of 2013, 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 2014 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. The notes were not convertible under this provision in 2013, 2012 or 2011. 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	$ 48.09	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 63.62	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 106.75	June 14, 2019

(d) Discount as of December 31, 2013 and 2012 included $303 million and $376 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method. Discount also included $33 million and $40 million as of December 31, 2013 and 2012, respectively, associated with our term loan discussed further below.

(e) See Note 11 for further discussion related to these instruments.

(f) As of December 31, 2012, there was $1 million of discount associated with the 7.625% Senior Notes due 2013.

Total principal amount of debt maturities, using the earliest conversion date for contingent convertible senior notes, for the five years ended after December 31, 2013 are as follows:

	Principal Amount of Debt Securities
	($ in millions)
2014	$ —
2015	1,661
2016	905
2017	4,301
2018	1,113
2019 and thereafter	5,250
Total	$ 13,230

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. 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 facility bear interest at our option, at either (i) the Eurodollar rate, which is based on the London Interbank Offered Rate (LIBOR), plus a margin of 4.50% or (ii) a base rate equal to the greater of (a) the Bank of America, N.A. prime rate, (b) the federal funds effective rate plus 0.50% per annum and (c) 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.

The term loan matures on December 2, 2017 and may be voluntarily repaid before November 9, 2015 at par plus a specified premium and 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 as of December 31, 2013. 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.

In 2012, we used the proceeds from the term loan, along with proceeds from asset sales, to repay our $4.0 billion term loan credit facility established in May 2012. We recorded $200 million of losses associated with the repayment, including $86 million of unamortized deferred charges and $114 million of unamortized 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 direct and indirect 100% owned subsidiaries. See Note 21 for 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 senior notes and 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 at least $50 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. The applicable 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 2013, we issued $2.3 billion in aggregate principal amount of senior notes at par in a registered public offering. The offering included three series of notes: $500 million in aggregate principal amount of 3.25% Senior Notes due 2016; $700 million in aggregate principal amount of 5.375% Senior Notes due 2021; and $1.1 billion in aggregate principal amount of 5.75% Senior Notes due 2023. We used a portion of the net proceeds of $2.274 billion to repay outstanding indebtedness under our corporate revolving bank credit facility and to purchase $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million pursuant to tender offers. We recorded a loss of approximately $37 million associated with the tender offers, including $32 million in premiums and $5 million of unamortized deferred charges. During the third quarter of 2013, we retired at maturity the remaining $247 million aggregate principal amount outstanding of our 7.625% Senior Notes due 2013.

During 2012, we issued $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 (the "2019 Notes") in a registered public offering. We used the net proceeds of $1.263 billion from the offering to repay outstanding indebtedness under our corporate revolving bank credit facility. On May 13, 2013, we redeemed the 2019 Notes at par pursuant to notice of special early redemption. We recorded a loss of approximately $33 million associated with the redemption, including $19 million of unamortized deferred charges and $14 million of discount. As described in the following paragraph, the special early redemption was the subject of litigation.

In March 2013, the Company brought suit in the U.S. District Court for the Southern District of New York (the "Court") against The Bank of New York Mellon Trust Company, N.A. ("BNY Mellon"), the indenture trustee for the 2019 Notes. The Company sought a declaration that the notice it issued on March 15, 2013 to redeem all of the 2019 Notes at par (plus accrued interest through the redemption date) was timely and effective pursuant to the special early redemption provision of the supplemental indenture governing the 2019 Notes. BNY Mellon asserted that the March 15, 2013 notice was not effective to redeem the 2019 Notes at par because it was not timely for that purpose and because of the specific phrasing in the notice that provided it would not be effective unless the Court concluded it was timely. The Court conducted a trial on the matter in late April and on May 8, 2013 ruled in the Company's favor. On May 11, 2013, BNY Mellon filed notice of an appeal of the decision with the United States Court of Appeals for the Second Circuit and the appeal is currently pending.

No scheduled principal payments are required on our senior notes until February 2015.

COO Senior Notes

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 by COO 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 enabling holders of the COO senior notes to exchange the privately placed COO senior notes for publicly registered notes with substantially the same terms. The exchange offer was completed in July 2013.

Bank Credit Facilities

During 2013, we had the following two revolving bank credit facilities as sources of liquidity:

	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, 2013	$ —	$ 405
Letters of credit outstanding as of December 31, 2013	$ 23	$ —

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

(b) Borrower is COO.

Although the applicable interest rates under our corporate credit facility fluctuate 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. 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.

Our corporate credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in compliance with all covenants under our corporate credit facility agreement as of December 31, 2013.

In September 2012, we entered into an amendment to the credit facility agreement, effective September 30, 2012. The amendment, among other things, adjusted our required indebtedness to EBITDA ratio through the earlier of (i) December 31, 2013 and (ii) the date on which we elected to reinstate the indebtedness to EBITDA ratio in effect prior to the amendment (in either case, the “Amendment Effective Period”). The credit facility amendment also increased the applicable margin by 0.25% for borrowings during the Amendment Effective Period when credit extensions exceeded 50% of the borrowing capacity. The amendment did 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. During the Amendment Effective Period, the amendment increased the maximum indebtedness to EBITDA ratio to 6.00 to 1.00 as of September 30, 2012, 5.00 to 1.00 as of December 31, 2012 and 4.75 to 1.00 as of March 31, 2013. On June 28, 2013, we elected to reinstate the indebtedness to EBITDA ratio to 4.00 to 1.00, which was the ratio in effect prior to the amendment.

Our corporate credit 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 credit facility 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 such indebtedness. The credit facility agreement also has cross default provisions that apply to our secured hedging 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, which 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 enter into asset sales, 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 as of December 31, 2013. 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.

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. 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. Chesapeake and the officer and director defendants moved for summary judgment on grounds of loss causation and materiality on December 28, 2011, and the motion was granted as to all claims as a matter of law on March 29, 2013. Final judgment in favor of Chesapeake and the officer and director defendants was entered on June 21, 2013, and the plaintiff filed a notice of appeal on July 19, 2013 in the U.S. Court of Appeals for the Tenth Circuit. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.

A derivative action relating to the July 2008 offering filed in the U.S. District Court for the Western District of Oklahoma on September 6, 2011 is pending. Following the denial on September 28, 2012 of its motion to dismiss and pursuant to court order, nominal defendant Chesapeake filed an answer in the case on October 12, 2012. By stipulation between the parties, the case is stayed pending resolution of the Tenth Circuit appeal.

2012 Securities and Shareholder Litigation. 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 its former Chief Executive Officer (CEO), Aubrey K. McClendon. 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 asserted claims under Sections 10(b) (and Rule 10b-5 promulgated thereunder) 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. On December 6, 2012, the Company and other defendants filed a motion to dismiss the action. On April 10, 2013, the Court granted the motion, and on April 16, 2013 entered judgment against the plaintiff and dismissed the complaint with prejudice. The plaintiff filed a notice of appeal on June 14, 2013 in the U.S. Court of Appeals for the Tenth Circuit. Briefing on the appeal was complete on August 2, 2013, and on November 18, 2013 argument was heard. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.

A related federal consolidated derivative action and an Oklahoma state court derivative action are stayed pursuant to the parties' stipulation pending resolution of the appeal in the federal securities class action.

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. On August 21, 2012, the District Court granted the Company's motion to dismiss for lack of derivative standing, and the plaintiff appealed the ruling on December 6, 2012.

Regulatory Proceedings. 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 2012 securities and shareholder lawsuits. On December 21, 2012, the SEC's Fort Worth Regional Office advised Chesapeake that its inquiry is continuing as an investigation. The Company is providing information and testimony to the SEC pursuant to subpoenas and otherwise in connection with this matter and is also responding to related inquiries from other governmental and regulatory agencies and self-regulatory organizations.

The Company has received, from the Antitrust Division of the U.S. Department of Justice (DOJ) and certain state governmental agencies, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state laws relating to our purchase and lease of oil and gas rights in various states. Chesapeake has engaged in discussions with the DOJ and state agencies and continues to respond to such subpoenas and demands, including a subpoena issued by the Michigan Department of Attorney General relating to its investigation of possible violations of that state's criminal solicitation law.

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, 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. Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits allege that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. The Company is defending against certain pending claims, has resolved a number of claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits.

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 Proceedings

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 environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions 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.

On December 19, 2013, our subsidiary Chesapeake Appalachia, LLC (CALLC) entered into a consent decree with the U.S. Environmental Protection Agency (EPA), the U.S. Department of Justice (DOJ) and the West Virginia Department of Environmental Protection (WVDEP) to resolve alleged violations of the Clean Water Act (CWA) and the West Virginia Water Pollution Control Act at 27 sites in West Virginia. In a complaint filed against CALLC the same day in the U.S. District Court for the Northern District of West Virginia, the EPA and WVDEP alleged that CALLC impounded streams and discharged sand, dirt, rocks and other fill material into streams and wetlands without a federal permit in order to construct well pads, impoundments, road crossings and other facilities related to natural gas extraction. The consent decree, also lodged on December 19, 2013, is subject to court approval.

The consent decree requires CALLC to pay a civil penalty of approximately $3 million, to be divided evenly between the U.S. and the state of West Virginia. The consent decree settlement also requires that CALLC restore the affected wetlands and streams in accordance with an agreed plan, monitor the restored sites for up to 10 years to assure the success of the restoration, and implement a comprehensive compliance program to ensure future compliance with the CWA and applicable West Virginia law. To offset the impacts to sites, CALLC is required by the consent decree to perform compensatory mitigation, which will likely involve purchasing credits from a wetland mitigation bank located in a local watershed. Eleven of the sites covered by the consent decree were subject to orders for compliance issued by the EPA in 2010 and 2011. Since then, CALLC has been correcting the alleged violations and restoring those sites in compliance with EPA’s orders. The settlement resolves alleged violations of both the CWA and state law.

In a related case, in December 2012, CALLC pled guilty to three misdemeanor violations of the CWA for unauthorized discharge at one of the sites subject to the consent decree of crushed stone and gravel into a local stream to create a roadway to improve access to a drilling site. CALLC paid a $600,000 penalty and has fully restored the site. We believe that CALLC is in compliance with the terms of probation. By operation of law, a CWA conviction triggers “disqualification”, by which the disqualified entity is prohibited from receiving federal contracts or benefits until the EPA certifies that the conditions giving rise to the conviction have been corrected. Disqualification of CALLC has not had, and we do not expect it to have, a material adverse impact on our business.

Commitments

Rig, Compressor and Other Operating Leases

As of December 31, 2013, we leased 45 rigs under master lease agreements with an aggregate undiscounted future lease commitment of $76 million. The lease commitments are guaranteed by Chesapeake and certain of its subsidiaries. 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 2013, we purchased 23 leased rigs from various lessors for an aggregate purchase price of approximately $141 million and paid approximately $22 million in lease termination costs. Through these transactions, we lowered our minimum aggregate undiscounted future rig lease payments by approximately $142 million. See Note 23 for further discussion related to additional leased rigs purchased subsequent to December 31, 2013.

As of December 31, 2013, we leased 1,781 compressors under master lease agreements with an aggregate undiscounted future lease commitment of $260 million. The lease commitments are guaranteed by Chesapeake and certain of its subsidiaries. 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 2013, we purchased 541 leased compressor units from various lessors for an aggregate purchase price of approximately $97 million, lowering our minimum aggregate undiscounted future compressor lease payments by approximately $73 million. See Note 23 for further discussion related to additional leased compressors purchased subsequent to December 31, 2013.

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, 2013			
	Rigs	Compressors	Other	Total
	($ in millions)			
2014	$ 51	$ 53	$ 13	$ 117
2015	11	50	11	72
2016	6	104	9	119
2017	7	23	3	33
2018	1	29	2	32
After 2018	—	1	1	2
Total	$ 76	$ 260	$ 39	$ 375

Rent expense for rigs, compressors and other equipment, including short-term rentals, for the years ended December 31, 2013, 2012 and 2011 was $158 million, $185 million and $184 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, where appropriate, 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 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, 2013
	($ in millions)
2014	$ 2,002
2015	1,829
2016	1,921
2017	1,948
2018	1,762
2019 - 2099	7,728
Total	$ 17,190

Drilling Contracts

Chesapeake has contracts with various drilling contractors to utilize approximately eight rigs with terms ranging from six months to three years. These commitments are not recorded in the accompanying consolidated balance sheets. As of December 31, 2013, the aggregate undiscounted minimum future payments under these drilling rig commitments are presented below:

	December 31, 2013
	($ in millions)
2014	$ 36
2015	5
Total	$ 41

In December 2013, we terminated a drilling contract prior to the end of its term and recognized a $15 million charge that is included in impairments of fixed assets and other in our consolidated statement of operations.

Drilling Commitments

In December 2011, as part of our Utica joint venture development agreement with Total S.A. (Total) (see Note 12), 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 July 31, 2015. Through December 31, 2013, we had spud 423 cumulative Utica wells and had met our 2012 and 2013 commitments. If we fail to meet the drilling commitment at July 31, 2015 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 the number of wells drilled in the subsequent 12-month period represented by the shortfall versus our 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.

Property and Equipment Purchase Commitments

Much of the oilfield services and other equipment we purchase requires long production lead times. As a result, we have outstanding orders and commitments for such equipment. As of December 31, 2013, we had $30 million of purchase commitments related to future inventory and capital expenditures for oilfield services and other equipment.

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 12 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

Under the terms of our joint venture agreements with Statoil, Total and Sinopec (see Note 12), 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. To date, we have satisfied our replacement commitments under the Statoil and Sinopec agreements. We had an estimated shortfall of approximately 13,000 net acres pursuant to our net acreage maintenance commitment with Total under the terms of our Barnett Shale joint venture agreement as of the December 31, 2012 measurement date and recorded a $26 million charge in impairments of fixed assets and other in our consolidated statement of operations. We revised our estimate of the net acreage shortfall to be approximately 14,000 net acres as of December 31, 2013 and recorded an additional $2 million charge in 2013. Total has disputed our estimate of the shortfall, however, and the cash payment we ultimately make to Total could exceed amounts we have accrued.

Affiliate Commitments

Under the terms of our corporate revolving bank credit facility, certain of our subsidiaries, including our oilfield services companies, are not guarantors of the credit facility debt. Transactions between us and our non-guarantor subsidiaries may affect our EBITDA or indebtedness for purposes of our credit facility covenant calculations, but they would have no effect on the consolidated financial statements because the transactions would be eliminated through consolidation. See Note 3 for discussion of our covenant calculations.

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 rigs or utilize a specific number of its hydraulic fracturing fleets. As of December 31, 2013, we had recognized a nominal amount for non-utilization pursuant to the agreement and eliminated its impact 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 been required to enter into any backstop contracts.

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 12 for further discussion of our VPP transactions.

5. Other Liabilities

Other current liabilities as of December 31, 2013 and 2012 are detailed below.

	December 31,	
	2013	2012
	($ in millions)	
Revenues and royalties due others	$ 1,409	$ 1,337
Accrued natural gas, oil and NGL drilling and production costs	457	525
Joint interest prepayments received	464	749
Accrued compensation and benefits	320	225
Other accrued taxes	161	130
Accrued dividends	101	101
Other	599	674
Total other current liabilities	$ 3,511	$ 3,741

Other long-term liabilities as of December 31, 2013 and 2012 are detailed below.

	December 31, 2013	December 31, 2012
	($ in millions)	
CHK Utica ORRI conveyance obligation[(a)]	$ 250	$ 275
CHK C-T ORRI conveyance obligation[(b)]	149	164
Financing obligations[(c)]	31	175
Mortgages payable[(d)]	—	56
Other	554	506
Total other long-term liabilities	$ 984	$ 1,176

(a) $13 million and $18 million of the total $263 million and $293 million obligations are recorded in other current liabilities as of December 31, 2013 and December 31, 2012, respectively. See Note 8 for further discussion of the transaction.

(b) $12 million and $14 million of the total $161 million and $178 million obligations are recorded in other current liabilities as of December 31, 2013 and December 31, 2012, respectively. See Note 8 for further discussion of the transaction.

(c) As of December 31, 2012, this amount consisted primarily of an obligation related to 111 real estate surface properties in the Fort Worth, Texas area that we financed in 2009 for approximately $145 million and for which we entered into a 40-year master lease agreement whereby 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. On November 1, 2013, we terminated the financing master lease agreement on the surface properties for $258 million and recorded a loss of approximately $123 million associated with the extinguishment.

(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 term loan which had a floating interest rate of prime plus 275 basis points. In 2013, we prepaid the term loan in full without penalty. As of December 31, 2013, the building was classified as property and equipment held for sale on our consolidated balance sheet.

6. Income Taxes

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

	Years Ended December 31, 2013	2012	2011
	($ in millions)		
Current			
Federal	$ —	$ —	$ —
State	22	47	13
	22	47	13
Deferred			
Federal	502	(358)	1,044
State	24	(69)	66
	526	(427)	1,110
Total	$ 548	$ (380)	$ 1,123

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, 2013	2012	2011
	($ in millions)		
Income tax expense (benefit) at the federal statutory rate (35%)	$ 505	$ (341)	$ 1,008
State income taxes (net of federal income tax benefit)	38	(38)	74
Other	5	(1)	41
Total	$ 548	$ (380)	$ 1,123

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, 2013	2012
	($ in millions)	
Deferred tax liabilities:		
Natural gas and oil properties	$ (2,631)	$ (1,999)
Other property and equipment	(371)	(436)
Volumetric production payments	(1,216)	(1,432)
Contingent convertible debt	(439)	(416)
Deferred tax liabilities	(4,657)	(4,283)
Deferred tax assets:		
Net operating loss carryforwards	535	711
Derivative instruments	108	172
Asset retirement obligations	153	142
Investments	130	106
Deferred stock compensation	66	47
Accrued liabilities	120	90
Noncontrolling interest liabilities	152	178
Alternative minimum tax credits	317	225
Other	40	55
Deferred tax assets	1,621	1,726
Valuation allowance	(148)	(160)
Net deferred tax assets	1,473	1,566
Net deferred tax assets (liabilities)	$ (3,184)	$ (2,717)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 223	$ 90
Non-current deferred income tax liability	(3,407)	(2,807)
Total	$ (3,184)	$ (2,717)

As of December 31, 2013 and 2012, we classified $223 million and $90 million, respectively, 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, 2013 and 2012, non-current deferred tax liabilities on the consolidated balance sheets that were primarily attributable to temporary differences associated with oil and gas properties and volumetric production payments were $3.407 billion and $2.807 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 U.S. 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, 2013 totaled $24 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, 2013, Chesapeake had federal income tax NOL carryforwards of approximately $592 million and state NOL carryforwards of approximately $7.0 billion (deferred tax assets related to these state NOL carryforwards were $328 million), which excludes the NOL carryforwards related to unrecognized tax benefits and stock compensation windfalls that have not been recognized under U.S. GAAP. Additionally, we had $51 million of alternative minimum tax (AMT) NOL carryforwards, net of unrecognized tax benefits, available as a deduction against future AMT income and $599 million of AMT NOL carrybacks to be used against prior year AMT income. The NOL carryforwards expire from 2025 through 2033. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income. As of December 31, 2013 and 2012, we had deferred tax assets of $1.621 billion and $1.726 billion, respectively, upon which we had a valuation allowance of $148 million and $160 million, respectively, for certain state NOL carryforwards that we have concluded are not more likely than not to be utilized prior to expiration. The net decrease in the valuation allowance of $12 million is reflected as a reduction to the 2013 income tax provision and is due to changes in judgment regarding the future realizability of our state NOL carryforwards.

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 federal and AMT NOLs as of December 31, 2013 and any related limitations:

	Total	Total Limitation	Annual Limitation
		($ in millions)	
Federal net operating loss	$ 592	$ 49	$ 15
AMT net operating loss	$ 650	$ 35	$ 15

As of December 31, 2013, 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, 2013 and 2012, the amount of unrecognized tax benefits related to NOL carryforwards and state tax liabilities associated with uncertain tax positions was $644 million and $599 million, respectively. Of these amounts, $4 million and $1 million, respectively, are related to state tax liabilities while the remainder is related to NOL carryforwards. 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. No material changes to the current uncertain tax positions are expected within the next 12 months. As of December 31, 2013 and 2012, we had accrued liabilities of $13 million and $6 million, respectively, 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:

	2013	2012	2011
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 599	$ 369	$ 34
Additions based on tax positions related to the current year	15	134	135
Additions to tax positions of prior years	30	96	200
Settlements	—	—	—
Unrecognized tax benefits at end of period	$ 644	$ 599	$ 369

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. The federal tax returns for 1999 through 2006 remain subject to examination for the purpose of determining the amount of remaining tax NOL and other carryforwards. The 2007 through 2013 years remain open for all purposes of examination by the IRS and other taxing authorities in material jurisdictions.

7. Related Party Transactions

Former Chief Executive Officer

On April 1, 2013, Aubrey K. McClendon, the co-founder of the Company, ceased serving as President and CEO and as a director of the Company pursuant to his agreement with the Board of Directors announced on January 29, 2013. Since Chesapeake was founded in 1989, Mr. McClendon and his affiliates have acquired working interests in virtually all of our natural gas and oil properties by participating in our drilling activities under the terms of Mr. McClendon's employment agreements and, since 2005, the Founder Well Participation Program (FWPP). The Company is reimbursed for costs associated with leasehold acquired under the FWPP, and well costs are charged to FWPP interests based on percentage ownership. On April 30, 2012, the Company's Board of Directors and Mr. McClendon agreed to terminate the FWPP 18 months before the end of the 10-year term approved by our shareholders in June 2005. Mr. McClendon has elected to participate in the FWPP through the expiration of the FWPP on June 30, 2014 at the maximum 2.5% working interest permitted, the same participation percentage that Mr. McClendon has elected every year since 2004. The Compensation Committee of the Board of Directors, which administers and interprets the FWPP, is reviewing with the assistance of independent counsel the prior administration of the plan. As of December 31, 2013 and 2012, we had accrued accounts receivable from Mr. McClendon of $62 million and $23 million, respectively, representing FWPP joint interest billings. 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 percentages. These interests were acquired through the FWPP.

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 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. The incentive award was subject to a clawback provision 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 recognized 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 incentive award clawback did not apply to Mr. McClendon's termination in 2013. See Note 17 for additional information on the terms of his separation from the Company.

On July 26, 2013, the Company and Mr. McClendon rescinded the December 2008 sale of an antique map collection pursuant to the terms of a settlement agreement terminating pending shareholder litigation that was approved by the District Court of Oklahoma County, Oklahoma on January 30, 2012 and affirmed on appeal. The Company returned the subject maps to Mr. McClendon, and Mr. McClendon paid the Company $12 million plus interest.

Equity Method Investees

Other than Mr. McClendon, only our equity method investees were considered related parties. During 2013, 2012 and 2011, we had the following related party transactions with our equity method investees.

	Years Ended December 31, 2013	2012	2011
	($ in millions)		
Purchases[a]	$ —	$ 73	$ —
Sales[b]	$ 666	$ 392	$ 171
Services[c]	$ 397	$ 480	$ 369

(a) Purchase of equipment from FTS.

(b) In 2013, 2012 and 2011, Chesapeake sold produced gas to our 30%-owned investee, Twin Eagle Resource Management LLC.

(c) Hydraulic fracturing and other services provided to us by FTS in the ordinary course of business. As well operators, we are reimbursed by other working interest owners through the joint interest billing process for their proportionate share of these costs.

The table below shows the total related party amounts due from and due to our equity method investees.

	December 31, 2013	2012	2011
	($ in millions)		
Amounts due from equity method investment related parties	$ 47	$ 67	$ 29
Amounts due to equity method investment related parties	$ 1	$ 42	$ 115

8. Equity

Common Stock

The following is a summary of the changes in our common shares issued for 2013, 2012 and 2011:

	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Shares issued as of January 1	666,468	660,888	655,251
Restricted stock issuances (net of forfeitures)[a]	(599)	5,038	4,961
Stock option exercises	323	542	565
Preferred stock conversion	—	—	111
Shares issued as of December 31	666,192	666,468	660,888

(a) In 2013, we began granting restricted stock units (RSUs) in lieu of restricted stock awards (RSAs) to non-employee directors and employees. Shares of common stock underlying RSUs are issued when the units vest, whereas restricted shares of common stock are issued on the grant date of RSAs. We refer to RSAs and RSUs collectively as restricted stock.

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2013:

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	37.1850	$ 26.8926	May 17, 2015	$ 34.9604
5.75% (series A) cumulative convertible non-voting	May 2010	$ 1,000	Any time	35.9339	$ 27.8289	May 17, 2015	$ 36.1776
4.50% cumulative convertible	September 2005	$ 100	Any time	2.2969	$ 43.5375	September 15, 2010	$ 56.5988
5.00% cumulative convertible (series 2005B)	November 2005	$ 100	Any time	2.5990	$ 38.4757	November 15, 2010	$ 50.0184

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

The following reflects the shares outstanding of our preferred stock for 2013, 2012 and 2011:

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	(in thousands)			
Shares outstanding as of January 1, 2013 and December 31, 2013	1,497	1,100	2,559	2,096
Shares outstanding as of January 1, 2012 and December 31, 2012	1,497	1,100	2,559	2,096
Shares outstanding as of 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

In 2011, 3,000 shares of our 5.75% Cumulative Convertible Preferred Stock were converted into 111,111 shares of our common stock. There was no gain or loss associated with this conversion.

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.

Accumulated Other Comprehensive Income (Loss)

For the year ended December 31, 2013, changes in accumulated other comprehensive income (loss) by component, net of tax, are detailed below.

	Net Gains (Losses) on Cash Flow Hedges	Net Gains (Losses) on Investments	Total
		($ in millions)	
Balance, December 31, 2012	$ (189)	$ 7	$ (182)
Other comprehensive income before reclassifications	2	(6)	(4)
Amounts reclassified from accumulated other comprehensive income	20	4	24
Net current period other comprehensive income	22	(2)	20
Balance, December 31, 2013	$ (167)	$ 5	$ (162)

For the year ended December 31, 2013, amounts reclassified from accumulated other comprehensive income (loss), net of tax, into the consolidated statement of operations are detailed below.

Details About Accumulated Other Comprehensive Income (Loss) Components	Affected Line Item in the Statement Where Net Income is Presented	Year Ended December 31, 2013
		($ in millions)
Net losses on cash flow hedges:		
Commodity contracts	Natural gas, oil and NGL revenues	$ 20
Investments:		
Impairment of investment	Impairment of investment	6
Sale of investment	Gain on sale of investment	(2)
Total reclassifications for the period, net of tax		$ 24

Noncontrolling Interests

Cleveland Tonkawa Financial Transaction. We formed 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 indebtedness 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 plays between the top of the Tonkawa and the top of the Big Lime formations 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 future net wells to be drilled on the contributed 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 remaining 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 C-T LLC Agreement, CHK C-T is required to retain an amount of cash equal to the next two quarters of preferred dividend payments and, until December 31, 2013, it was also required to retain an amount of cash equal to its projected operating funding shortfall for the next six months. The amounts retained, approximately $38 million and $57 million as of December 31, 2013 and 2012, respectively, were reflected as restricted cash on our consolidated balance sheets.

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 may 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 can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of December 31, 2013 and 2012, the redemption price and the liquidation preference were each approximately $1,245 and $1,305, respectively, per preferred share.

We have committed to drill and complete, 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. Under the development agreement, approximately 75 and 85 qualified net wells were added in 2013 and 2012, respectively. Through December 31, 2013, we had met the drilling commitments associated with the CHK C-T transaction.

The CHK C-T investors' right to receive, proportionately, a 3.75% ORRI in the contributed wells and up to 1,000 future net wells on our contributed leasehold is subject to an increase to 5% on net wells earned in any year following a year in which we do not meet our net well commitment under 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 future net wells. If at any time CHK C-T holds 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 ORRIs. 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 ORRIs 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. Under the ORRI obligation, we delivered an ORRI in approximately 84 net wells in 2013 and 77 net wells in 2012. While operations began on April 1, 2012, all wells completed since January 1, 2012 are credited to the ORRI obligation of 1,000 future net wells. Through December 31, 2013, we were on target to meet the ORRI conveyance commitments associated with the CHK C-T transaction.

As of December 31, 2013 and 2012, $1.015 billion of noncontrolling interests on our consolidated balance sheets was attributable to CHK C-T. For 2013 and 2012, income of $75 million and $57 million, respectively, was attributable to the noncontrolling interests of CHK C-T.

Utica Financial Transaction. We formed 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 indebtedness 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 remaining 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 amounts reserved for paying such dividends, approximately $37 million and $44 million as of December 31, 2013 and 2012, respectively, were reflected as restricted cash on our consolidated balance sheets. In addition, pursuant to the CHK Utica LLC Agreement, with respect to any divestiture proceeds as defined by the agreement, CHK Utica is required to separately account for, and dedicate all of such divestiture 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 of December 31, 2012, $155 million of proceeds received from such divestitures was recorded as restricted cash in other long-term assets on our consolidated balance sheet. In 2013, we used all of the proceeds for CHK Utica capital expenditures.

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. 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. 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 may 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 provide the investors the greater of a 17.5% internal rate of return or a return on investment of 2.0x. The preferred shares can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of December 31, 2013 and 2012, the redemption price and the liquidation preference were each approximately $1,252 and $1,322, respectively, per preferred share.

We have committed to drill and complete, 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. 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. 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 12 for further discussion of the joint venture. Under the development agreement, approximately 111 and 61 qualified net wells were added in 2013 and 2012, respectively. Through December 31, 2013, we had met the drilling commitments associated with the CHK Utica transaction.

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 earned in any year following a year in which we do not meet our net well commitment under 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 ORRIs. 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 ORRIs 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. Under the ORRI obligation, we delivered an ORRI in approximately 149 new net wells in 2013 and 28 net wells in 2012. Because we did not meet our ORRI commitment in 2012, the ORRI increased to 4% for wells earned in 2013, and the ultimate number of wells in which we must assign an interest will be reduced accordingly. Through December 31, 2013, we were on target to meet the ORRI conveyance commitments associated with the CHK Utica transaction.

As of December 31, 2013 and 2012, $807 million and $950 million of noncontrolling interests on our consolidated balance sheets, respectively, were attributable to CHK Utica. For 2013 and 2012, income of approximately $79 million and $88 million, respectively, was attributable to the noncontrolling interests of CHK Utica. In 2013, we purchased approximately 190,000 preferred shares of CHK Utica from existing investors for approximately $212 million, or approximately $1,115 per share plus accrued dividends, reducing the amount of outstanding preferred shares held by third-party investors by approximately 15%. The difference between the cash paid for the preferred shares and the carrying value of the noncontrolling interest acquired of $69 million is reflected in retained earnings and as a reduction to net income available to common stockholders for purposes of our EPS computations.

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, 2013 and 2012, we had drilled or caused to be drilled approximately 82 and 55 development wells, respectively, as calculated under the development agreement, and the maximum amount recoverable under the drilling support lien was approximately $79 million and $140 million, respectively.

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. As detailed in the table below, the distribution made with respect to the subordinated units to Chesapeake were either reduced or eliminated for each of the most recent six quarters of distributions paid. 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.

For the years ended December 31, 2013 and 2012, the Trust declared and paid the following distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
June 2013 - August 2013	November 29, 2013	$ 0.6671	$ —
March 2013 - May 2013	August 29, 2013	$ 0.6900	$ 0.1432
December 2012 - February 2013	May 31, 2013	$ 0.6900	$ 0.3010
September 2012 - November 2012	March 1, 2013	$ 0.6700	$ 0.3772
June 2012 - August 2012	November 29, 2012	$ 0.6300	$ 0.2208
March 2012 - May 2012	August 30, 2012	$ 0.6100	$ 0.4819
December 2011 - February 2012	May 31, 2012	$ 0.6588	$ 0.6588
September 2011 - November 2011	March 1, 2012	$ 0.7277	$ 0.7277

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, 2013 and 2012, $314 million and $356 million, respectively, of noncontrolling interests on our consolidated balance sheets, respectively, were attributable to the Trust. For 2013 and 2012, income of approximately $20 million and $35 million, respectively, was attributable to the Trust's noncontrolling interests in our consolidated statements of operations. See Note 14 for further discussion of VIEs.

Wireless Seismic, Inc. We have a controlling 51% equity interest in Wireless Seismic, Inc. (Wireless), a privately owned company engaged in research, development and 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 of December 31, 2013 and 2012, $9 million and $5 million, respectively, of noncontrolling interests on our consolidated balance sheets, respectively, were attributable to Wireless. In each of 2013 and 2012, losses of $4 million were attributable to noncontrolling interests of Wireless in our consolidated statements of operations.

9. Share-Based Compensation

Chesapeake's share-based compensation program consists of restricted stock, stock options and performance share units (PSUs) granted to employees and restricted stock granted to non-employee directors under our Long Term Incentive Plan. The restricted stock and stock options are equity-classified awards and the PSUs are liability-classified awards.

Share-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 59,300,000 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 147,108, 170,151 and 68,824 shares of restricted stock issued to our non-employee directors under the plan in 2013, 2012 and 2011, respectively. Additionally, there were 2.5 million, 5.0 million and 4.5 million restricted stock issued, net of forfeitures, to employees and consultants during 2013, 2012 and 2011, respectively, under the plan. As of December 31, 2013, there were 12.7 million shares remaining available for issuance under the plan.

Chesapeake's 2003 Stock Incentive Plan terminated in April 2013. Restricted stock was awarded to employees and consultants of Chesapeake under the plan prior to its termination. Subject to any adjustments as provided by the plan, the aggregate number of shares available for awards under the plan was limited to 10,000,000 shares. Restricted stock became vested at dates determined by a committee of the Board of Directors. The plan was approved by our shareholders. There were nominal amounts of restricted stock, net of forfeitures, issued under the plan during 2013 and 2012 and 0.4 million restricted stock, net of forfeitures, issued under the plan during 2011.

Under Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, a maximum of 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 250,000 shares. This plan has been approved by our shareholders. In 2013, 2012 and 2011, 20,000, 30,000 and 10,000 shares, respectively, of common stock were awarded to new directors under the plan. As of December 31, 2013, there were 130,000 shares remaining available for issuance under the plan.

Equity-Classified Awards

Restricted Stock. We grant restricted stock to employees and non-employee directors. Restricted stock vests over a minimum of three years and the holder receives dividends or dividend equivalents on unvested shares. A summary of the changes in unvested shares of restricted stock during 2013, 2012 and 2011 is presented below.

	Number of Unvested Restricted Shares	**Weighted Average Grant Date Fair Value**
	(in thousands)	
Unvested shares as of January 1, 2013	18,899	$ 23.72
Granted	9,189	$ 19.68
Vested	(12,897)	$ 21.32
Forfeited	(1,791)	$ 22.86
Unvested shares as of December 31, 2013	13,400	$ 23.38
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

The aggregate intrinsic value of restricted stock that vested during 2013 was approximately $342 million based on the stock price at the time of vesting.

As of December 31, 2013, there was $195 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 3.6 years.

The vesting of certain restricted stock grants may 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 2013, 2012 and 2011, we recognized reductions in tax benefits related to restricted stock of $14 million, $32 million and $23 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

Stock Options. In 2013, we granted members of our senior management team stock options that will vest ratably over a three-year period. We also granted retention awards to certain officers of stock options that will vest one-third on each of the third, fourth and fifth anniversaries of the grant date. Each stock option award has an exercise price equal to the closing price of the Company's common stock on the grant date. Prior to 2006, we had granted stock options under several stock compensation plans which vested over a four-year period. Outstanding options expire ten years from the date of grant.

We utilized the Black-Scholes option pricing model to measure the fair value of the stock options that were granted in 2013. The expected life of an option is determined using the "simplified method", as there is not adequate historical exercise behavior available. Volatility assumptions are estimated based on an average of historical volatility over the expected life of an option. The risk-free interest rate is based on the U.S. Treasury rate in effect at the time of the grant over the expected life of the option. The dividend yield is based on an annual dividend yield, taking into account the Company's current dividend policy over the expected life of the option. The Company used the following weighted-average assumptions to estimate the fair value of the stock options granted in 2013:

Expected option life - years	6.49
Volatility	48.47%
Risk-free interest rate	1.30%
Dividend yield	1.82%

The following table provides information related to stock option activity for 2013, 2012 and 2011:

	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, 2013	481	$ 12.69	0.96	$ 2
Granted	5,264	$ 19.32		
Exercised	(346)	$ 10.82		$ 11
Expired	(131)	$ 19.31		
Outstanding at December 31, 2013	5,268	$ 19.28	6.66	$ 41
Exercisable at December 31, 2013	1,552	$ 18.82	1.97	$ 13
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

(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, 2013, there was $16 million of total unrecognized compensation cost related to stock options. The cost is expected to be recognized over a weighted average period of approximately 2.5 years.

The vesting of certain stock option grants may 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, 2013 and 2012, we recognized excess tax benefits related to stock options of $1 million and $2 million, respectively. 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.

We recorded the following compensation related to restricted stock and stock options during the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
Natural gas and oil properties	$ 52	$ 71	$ 112
General and administrative expenses	60	71	92
Natural gas, oil and NGL production expenses	21	24	33
Marketing, gathering and compression expenses	7	15	17
Oilfield services expenses	10	10	11
Total	$ 150	$ 191	$ 265

Liability-Classified Awards

Performance Share Units. In 2012 and 2013, we granted PSUs to senior management under our Long Term Incentive Plan which settle in cash at the end of their respective performance periods and which vest ratably over their respective terms. The 2012 awards were granted in one, two and three-year tranches and are settled in cash on the first, second and third anniversary dates of the awards, and the 2013 awards are settled in cash on the third anniversary of the awards. The ultimate number of units earned is based on the achievement of relative and absolute total shareholder return (TSR) and production and proved reserve growth performance goals. The market condition is a function of TSR, and generally requires a Monte Carlo simulation to determine the fair value.

For PSUs granted in 2012, each of the TSR and operational payout components can range from 0% to 125% resulting in a maximum total payout of 250%. For PSUs granted in 2013, the TSR component can range from 0% to 125% and each of the two operational components can range from 0% to 62.5%; however, the maximum total payout is capped at 200% in all cases and at 100% in situations where the Company's absolute TSR is less than zero. The following table presents a summary of our PSU awards as of December 31, 2013:

	Units	Fair Value as of Grant Date	Fair Value	Liability for Vested Amount
			($ in millions)	
2012 Awards [(a)]				
Payable 2014	278,083	$ 8	$ 11	$ 11
Payable 2015	834,248	23	31	30
Total 2012 Awards	1,112,331	$ 31	$ 42	$ 41
2013 Awards				
Payable 2016	1,600,438	$ 35	$ 58	$ 49

(a) In 2013, we paid $2 million related to 2012 PSU awards.

We recorded the following compensation related to PSUs during the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
Natural gas and oil properties	$ 9	$ 4	$ —
General and administrative expenses	34	8	—
Natural gas, oil and NGL production expenses	2	1	—
Marketing, gathering and compression expenses	2	1	—
Oilfield services expenses	1	—	—
Total	$ 48	$ 14	$ —

10. 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 $81 million, $91 million and $72 million to the 401(k) Plan in 2013, 2012 and 2011, 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 $14 million, $16 million and $12 million to the DC Plan during 2013, 2012 and 2011, 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, 2013, the Company had accrued approximately $3 million in accumulated post-employment benefit liability.

11. Derivative and Hedging Activities

Chesapeake uses commodity derivative instruments to secure attractive pricing and margins on production, to reduce its exposure to fluctuations in future commodity prices and to protect its expected operating cash flow against significant market movements or volatility. Chesapeake also uses derivative instruments to mitigate a portion of our exposure to interest rate and foreign currency exchange rate fluctuations. 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.

Natural Gas and Oil Derivatives

As of December 31, 2013 and 2012, our natural gas and oil 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.
- *Collars:* These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option strike price.
- *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 in exchange for a premium that allows a counterparty, on a specific date, to enter into a 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.

The estimated fair values of our natural gas and oil derivative instrument assets (liabilities) as of December 31, 2013 and 2012 are provided below.

	December 31, 2013		December 31, 2012	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Natural gas (tbtu):				
Fixed-price swaps	448	$ (23)	49	$ 24
Three-way collars	288	(7)	—	—
Call options	193	(210)	193	(240)
Call swaptions	12	—	—	—
Basis protection swaps	68	3	111	(15)
Total natural gas	1,009	(237)	353	(231)
Oil (mmbbl):				
Fixed-price swaps	25.3	(50)	28.1	68
Call options	42.5	(265)	73.8	(748)
Call swaptions	—	—	5.3	(13)
Basis protection swaps	0.4	1	5.5	—
Total oil	68.2	(314)	112.7	(693)
Total estimated fair value		$ (551)		$ (924)

The components of natural gas, oil and NGL sales for the years ended December 31, 2013, 2012 and 2011 are presented below.

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
Natural gas, oil and NGL sales	$ 6,923	$ 5,359	$ 5,259
Gains on natural gas, oil and NGL derivatives	129	919	772
Losses on ineffectiveness of cash flow hedges	—	—	(7)
Total natural gas, oil and NGL sales	$ 7,052	$ 6,278	$ 6,024

We have terminated certain commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. See further discussion below under *Cash Flow Hedges*.

Interest Rate Derivatives

As of December 31, 2013 and 2012, our interest rate derivative instruments consisted of 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.

The notional amount and the estimated fair value of our interest rate derivative liabilities as of December 31, 2013 and 2012 are provided below.

	December 31, 2013		December 31, 2012	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate swaps	$ 2,250	$ (98)	$ 1,050	$ (35)

The components of interest expense for the years ended 2013, 2012 and 2011 are presented below.

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
Interest expense on senior notes	$ 740	$ 732	$ 653
Interest expense on credit facilities	38	70	70
Interest expense on term loans	116	173	—
(Gains) losses on interest rate derivatives	58	(7)	14
Amortization of loan discount, issuance costs and other	91	89	39
Capitalized interest	(816)	(980)	(732)
Total interest expense	$ 227	$ 77	$ 44

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 seven years, we will recognize $14 million in net gains in earnings 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. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €11 million and we pay the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €344 million and we 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 our 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 an asset of $2 million as of December 31, 2013. The euro-denominated debt in long-term debt has been adjusted to $473 million as of December 31, 2013 using an exchange rate of $1.3743 to €1.00.

Additional Disclosures Regarding Derivative Instruments and Hedging Activities

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, 2013 and 2012 on a gross basis without regard to same-counterparty netting:

		Fair Value December 31,	
	Balance Sheet Location	**2013**	**2012**
		($ in millions)	
Asset Derivatives:			
Designated as hedging instruments:			
Foreign currency contracts	Long-term derivative instruments	$ 2	$ —
Total		2	—
Not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	29	110
Commodity contracts	Long-term derivative instruments	11	5
Total		40	115
Liability Derivatives:			
Designated as hedging instruments:			
Foreign currency contracts	Long-term derivative instruments	—	(20)
Total		—	(20)
Not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(231)	(157)
Commodity contracts	Long-term derivative instruments	(362)	(882)
Interest rate contracts	Short-term derivative instruments	(6)	—
Interest rate contracts	Long-term derivative instruments	(92)	(35)
Total		(691)	(1,074)
Total derivative instruments		$ (649)	$ (979)

As of December 31, 2013 and 2012, we did not have any cash collateral balances for these derivatives.

The following tables present the netting offsets of derivative assets and liabilities in the consolidated balance sheets as of December 31, 2013 and December 31, 2012:

	December 31, 2013			
	Derivative Assets		Derivative Liabilities	
	Short-Term	Long-Term	Short-Term	Long-Term
	($ in millions)			
Commodity Contracts:				
Gross amounts of recognized assets (liabilities)	$ 29	$ 11	$ (231)	$ (362)
Gross amounts offset in the consolidated balance sheet	(29)	(9)	29	9
Net amounts of assets (liabilities) presented in the consolidated balance sheet	—	2	(202)	(353)
Interest Rate Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	(6)	(92)
Gross amounts offset in the consolidated balance sheet	—	—	—	—
Net amounts of assets (liabilities) presented in the consolidated balance sheet	—	—	(6)	(92)
Foreign Currency Contracts:				
Gross amounts of recognized assets (liabilities)	—	2	—	—
Gross amounts offset in the consolidated balance sheet	—	—	—	—
Net amounts of assets (liabilities) presented in the consolidated balance sheet	—	2	—	—
Total derivatives as reported	$ —	$ 4	$ (208)	$ (445)

	December 31, 2012			
	Derivative Assets		Derivative Liabilities	
	Short-Term	Long-Term	Short-Term	Long-Term
	($ in millions)			
Commodity Contracts:				
Gross amounts of recognized assets (liabilities)	$ 110	$ 5	$ (157)	$ (882)
Gross amounts offset in the consolidated balance sheet	(52)	(3)	52	3
Net amounts of assets (liabilities) presented in the consolidated balance sheet	58	2	(105)	(879)
Interest Rate Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	—	(35)
Gross amounts offset in the consolidated balance sheet	—	—	—	—
Net amounts of assets (liabilities) presented in the consolidated balance sheet	—	—	—	(35)
Foreign Currency Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	—	(20)
Gross amounts offset in the consolidated balance sheet	—	—	—	—
Net amounts of assets (liabilities) presented in the consolidated balance sheet	—	—	—	(20)
Total derivatives as reported	$ 58	$ 2	$ (105)	$ (934)

A consolidated summary of the effect of derivative instruments on our consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011 is provided below, separating fair value, cash flow and undesignated derivatives.

Fair Value Hedges. The following table presents the gain (loss) recognized in our consolidated statements of operations for terminated instruments that were designated as fair value derivatives:

Fair Value Derivatives	Location of Gain (Loss)	Years Ended December 31, 2013	2012	2011
		($ in millions)		
Interest rate contracts	Interest expense	$ 5	$ 8	$ 16

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

	Years Ended December 31, 2013		2012		2011	
	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)					
Balance, beginning of period	$ (304)	$ (189)	$ (287)	$ (178)	$ (291)	$ (181)
Net change in fair value	3	2	10	6	368	228
(Gains) losses reclassified to income	32	20	(27)	(17)	(364)	(225)
Balance, end of period	$ (269)	$ (167)	$ (304)	$ (189)	$ (287)	$ (178)

Approximately $159 million of the $167 million of accumulated other comprehensive loss as of December 31, 2013 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. These amounts will be recognized in earnings in the month in which the originally forecasted hedged production occurs. As of December 31, 2013, we expect to transfer approximately $23 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. The remaining amounts will be transferred by December 31, 2022. As of December 31, 2013, none of our open commodity derivative instruments were designated as cash flow hedges.

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, 2013	2012	2011
		($ in millions)		
Gain (Loss) Recognized in AOCI (Effective Portion):				
Commodity contracts	AOCI	$ —	$ —	$ 392
Foreign currency contracts	AOCI	3	10	(24)
		$ 3	$ 10	$ 368
Gain (Loss) Reclassified from AOCI (Effective Portion):				
Commodity contracts	Natural gas, oil and NGL sales	$ (32)	$ 27	$ 402
Foreign currency contracts	Interest expense	—	—	(18)
Foreign currency contacts	Loss on purchase of debt	—	—	(20)
		$ (32)	$ 27	$ 364
Gain (Loss) Recognized in Income:				
Ineffective portion	Natural gas, oil and NGL sales	$ —	$ —	$ (7)
Amount initially excluded from effectiveness testing	Natural gas, oil and NGL sales	—	—	22
		$ —	$ —	$ 15

Undesignated Derivatives. The following table presents the gain (loss) recognized in our 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, 2013	2012	2011
		($ in millions)		
Commodity contracts	Natural gas, oil and NGL	$ 159	$ 892	$ 348
Interest rate contracts	Interest expense	(63)	(1)	(12)
Total		$ 96	$ 891	$ 336

Credit Risk

Over-the-counter traded derivative instruments expose us to our counterparties' credit risk. 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. As of December 31, 2013, our natural gas, oil and interest rate derivative instruments were spread among 16 counterparties.

Hedging Facility

We have a multi-counterparty secured hedging facility with 16 counterparties that have committed to provide approximately 1.063 bboe of hedging capacity for natural gas, oil and NGL price derivatives and 1.063 bboe for basis derivatives with an aggregate mark-to-market capacity of $17.0 billion under the terms of the facility. As of December 31, 2013, we had hedged under the facility 221 mmboe of our future production with price derivatives and 12 mmboe 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 redetermination dates and 1.30 times in between those dates, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility, indentures, term loan and equipment master lease agreements. 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.

12. Natural Gas and Oil Property Divestitures

Under full cost accounting rules, we have 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 have not involved a significant change in proved reserves or significantly altered the relationship between costs and proved reserves. Below is a discussion of our major oil and gas property divestitures for the years ended December 31, 2013, 2012 and 2011.

In 2013, we sold a wholly owned subsidiary, MKR Holdings, L.L.C. (MKR), to Chief Oil and Gas and two of its working interest partners, Enerplus and Tug Hill. Net proceeds from the transaction were approximately $490 million. MKR held producing wells and undeveloped acreage in the Marcellus Shale in Bradford, Lycoming, Sullivan, Susquehanna and Wyoming counties, Pennsylvania.

In 2013, we sold assets in the Haynesville Shale to EXCO Operating Company, LP (EXCO) for net proceeds of approximately $257 million. Subsequent to closing, we received approximately $47 million of additional net proceeds for post-closing adjustments. The assets sold included our operated and non-operated interests in approximately 9,600 net acres in DeSoto and Caddo parishes, Louisiana.

In 2013, we sold assets in the northern Eagle Ford Shale to EXCO for net proceeds of approximately $617 million. Subsequent to closing, in 2013 we received approximately $32 million of net proceeds for post-closing adjustments and may receive up to $64 million of additional net proceeds for further post-closing adjustments. The assets sold included approximately 55,000 net acres in Zavala, Dimmit, La Salle and Frio counties, Texas.

In 2012, we sold the vast majority of our Permian Basin assets, representing approximately 6% of our total proved reserves as of June 30, 2012, 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 $355 million of such consideration, including $320 million received subsequent to December 31, 2012, and we expect to receive the majority of the remaining contingent amount in 2014. 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 2012, we sold approximately 40,000 net acres of noncore leasehold in the Chitwood Knox play in Oklahoma for approximately $540 million in cash.

In 2012, we sold producing assets in the Midland Basin portion of the Permian Basin to affiliates of EnerVest, Ltd. for approximately $376 million in cash.

In 2012, we sold approximately 72,000 net acres of noncore leasehold in the Utica Shale play in Ohio to affiliates of EnerVest, Ltd. for approximately $358 million in cash.

In 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 net proceeds of approximately $572 million.

In 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.

Joint Ventures

In 2013, we completed a strategic joint venture with Sinopec International Petroleum Exploration and Production Corporation (Sinopec) in which Sinopec purchased a 50% undivided interest in approximately 850,000 acres (425,000 acres net to Sinopec) in the Mississippi Lime play in northern Oklahoma. Total consideration for the transaction was approximately $1.020 billion in cash, of which approximately $949 million of net proceeds was received upon closing. We also received an additional $90 million at closing related to closing adjustments for activity between the effective date and closing date of the transaction. We may receive up to an additional $71 million of net proceeds pursuant to post-closing adjustments. All exploration and development costs in the joint venture are shared proportionately between the parties with no drilling carries involved.

As of December 31, 2013, we had entered into eight 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 eight different resource plays and received cash of $8.0 billion and commitments by our counterparties to pay our share of future drilling and completion costs of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all drilling, completion and operations, the majority of leasing and, in certain transactions, marketing activities for the project. The carries paid by a joint venture partner are for a specified percentage of our drilling and completion costs. 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 carries 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	Initial Proceeds[b]	Total Drilling Carries	Total Initial Proceeds and Drilling Carries	Drilling Carries Remaining[c]
					($ in millions)		
Mississippi Lime	Sinopec	June 2013	50.0%	$ 949 [d]	$ —	$ 949	$ —
Utica	TOT	December 2011	25.0%	610	1,422 [e]	2,032	596
Niobrara	CNOOC	February 2011	33.3%	570	697 [f]	1,267	135
Eagle Ford	CNOOC	November 2010	33.3%	1,120	1,080	2,200	—
Barnett	TOT	January 2010	25.0%	800	1,403	2,203	—
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	FCX	July 2008	20.0%	1,650	1,508	3,158	—
				$ 8,049	$ 9,035	$ 17,084	$ 731

(a) Joint venture partners include Sinopec International Petroleum Exploration and Production (Sinopec), Total S.A. (TOT), CNOOC Limited (CNOOC), Statoil (STO), BP America (BP) and Freeport-McMoRan Copper & Gold (FCX), formerly known as Plains Exploration & Production Company.

(b) Excludes closing and post-closing adjustments.

(c) As of December 31, 2013.

(d) Excludes $71 million of net proceeds (or 7% of the total transaction) expected to be received pursuant to certain post-closing adjustments and approximately $90 million received at closing for closing adjustments.

(e) 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.

(f) 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.

During 2013, 2012 and 2011, our drilling and completion costs included the benefit of approximately $884 million, $784 million and $2.570 billion, respectively, in drilling and completion carries paid by our joint venture partners.

During 2013, 2012 and 2011, we sold interests in additional leasehold we acquired in the Marcellus, Barnett, Utica, Haynesville, Eagle Ford, Mid-Continent and Niobrara Shale plays to our joint venture partners for approximately $58 million, $272 million and $511 million, respectively.

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 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 wellbores.

As the operator of the properties from which the VPP volumes have been sold, we 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 our full cost ceiling test 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.

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. We have also 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	Location	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 during 2013, 2012 and 2011 were as follows:

	Year Ended December 31, 2013			
VPP #	Natural Gas	Oil	NGL	Total
	(bcf)	(mbbl)	(mbbl)	(bcfe)
10	13.5	547.0	1,509.0	25.8
9	17.0	213.2	455.7	21.0
8	68.1	—	—	68.1
6	4.8	24.0	—	4.9
5	7.5	25.4	—	7.7
4	10.2	54.7	—	10.5
3	8.1	—	—	8.1
2	10.3	—	—	10.3
1	14.5	—	—	14.5
	154.0	864.3	1,964.7	170.9

	Year Ended December 31, 2012			
VPP #	Natural Gas	Oil	NGL	Total
	(bcf)	(mbbl)	(mbbl)	(bcfe)
10	18.1	727.0	1,729.1	32.8
9	18.4	249.3	643.6	23.7
8	79.7	—	—	79.7
7	0.4	490.3	—	3.4
6	5.3	24.0	—	5.5
5	8.8	27.4	—	9.0
4	11.7	62.8	—	12.2
3	9.3	—	—	9.3
2	11.4	—	—	11.3
1	15.3	—	—	15.3
	178.4	1,580.8	2,372.7	202.2

	Year Ended December 31, 2011			
VPP #	Natural Gas	Oil	NGL	Total
	(bcf)	(mbbl)	(mbbl)	(bcfe)
10	—	—	—	—
9	17.3	250.5	615.4	22.5
8	101.2	—	—	101.2
7	0.4	773.0	—	5.0
6	6.0	27.0	—	6.2
5	11.0	35.9	—	11.2
4	13.8	75.1	—	14.3
3	10.7	—	—	10.7
2	12.5	—	—	12.5
1	16.3	—	—	16.3
	189.2	1,161.5	615.4	199.9

The volumes remaining to be delivered on behalf of our VPP buyers as of December 31, 2013 were as follows:

		Volume Remaining as of December 31, 2013			
VPP #	Term Remaining	Natural Gas	Oil	NGL	Total
	(in months)	(bcf)	(mmbbl)	(mmbbl)	(bcfe)
10	98	48.6	1.7	6.0	94.8
9	86	88.7	1.0	2.3	108.9
8	20	96.5	—	—	96.5
6	73	21.4	0.2	—	22.3
5	37	16.9	0.1	—	17.2
4	36	24.3	0.1	—	25.1
3	67	31.1	—	—	31.1
2	64	20.0	—	—	20.0
1	108	105.4	—	—	105.4
		452.9	3.1	8.3	521.3

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.

13. Investments

A summary of our investments, including our approximate ownership percentage as of December 31, 2013 and 2012, is presented below.

	Accounting Method	Approximate Ownership % December 31, 2013	Approximate Ownership % December 31, 2012	Carrying Value December 31, 2013	Carrying Value December 31, 2012
				($ in millions)	
FTS International, Inc.	Equity	30%	30%	$ 138	$ 298
Chaparral Energy, Inc.	Equity	20%	20%	143	141
Sundrop Fuels, Inc.	Equity	56%	50%	135	111
Clean Energy Fuels Corp. (common stock)	Fair Value	—%	1%	—	12
Clean Energy Fuels Corp. (convertible notes)	Cost	—%	—%	—	100
Gastar Exploration Ltd.	Fair Value	—%	10%	—	8
Other	—	—%	—%	61	58
Total investments				$ 477	$ 728

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 2013, we recorded negative equity method and other adjustments, prior to intercompany profit eliminations, of $177 million for our share of FTS's net loss and recorded an accretion adjustment of $14 million related to the excess of our underlying equity in net assets of FTS over our carrying value. The loss in 2013 primarily represents our proportionate share, net of tax, of an impairment recorded by FTS related to its non-depreciable assets. Additionally, in 2013, we purchased FTS common stock offered to existing stockholders for $3 million.

The carrying value of our investment in FTS was less than our underlying equity in net assets by approximately $54 million as of December 31, 2013, of which $14 million was attributed to non-depreciable assets. During 2013, the value attributed to non-depreciable assets decreased by $282 million, which primarily represents our proportionate share, net of tax, of an impairment recorded by FTS related to its non-depreciable assets noted above. The value not attributed to non-depreciable assets is being accreted over the estimated useful lives of the underlying assets.

Chaparral Energy, Inc. Chaparral Energy, Inc. (Chaparral), 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 2013, we recorded positive equity method adjustments of $10 million related to our share of Chaparral's net income, a $5 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 $48 million as of December 31, 2013. This excess was attributed to the natural gas and oil reserves held by Chaparral and was being amortized over the estimated life of these reserves based on a unit of production rate. Subsequent to December 31, 2013, we sold our investment in Chaparral for cash proceeds of $215 million.

Sundrop Fuels, Inc. Sundrop Fuels, Inc. (Sundrop), is a privately held cellulosic biofuels company based in Longmont, Colorado that is constructing a nonfood biomass-based "green gasoline" plant. In 2013, we recorded a $16 million charge related to our share of Sundrop's net loss. Additionally, in 2013, we funded our final investment of $40 million upon Sundrop's achievement of certain operational milestones. The carrying value of our investment in Sundrop was in excess of our underlying equity in net assets by approximately $62 million as of December 31, 2013. This excess will be amortized over the life of the plant, once it is placed into service.

Sold Investments

Clean Energy Fuels Corp. In 2013, we sold all of our shares of Clean Energy Fuels Corp. (NASDAQ:CLNE) (Clean Energy) common stock for cash proceeds of approximately $13 million. We recorded a $3 million gain related to the sale. In 2013, we sold our $100 million investment in Clean Energy convertible notes for cash proceeds of $85 million. The buyer also assumed our commitment to purchase the third and final $50 million tranche of Clean Energy convertible notes. We recorded a $15 million loss related to this sale.

Gastar Exploration Ltd. In 2013, we sold our investment in Gastar Exploration Ltd. (NYSE MKT:GST) for cash proceeds of $10 million.

Chesapeake Midstream Partners, L.P. 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, 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.

Glass Mountain Pipeline, LLC. In 2012, our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.L.C. (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.

Other. In 2013, we sold an equity investment for cash proceeds of $6 million and recorded a $5 million gain associated with the transaction.

The table below presents summarized financial information for our significant equity method investments, including FTS and Sundrop. The investee financial information reflects the most current financial information available to investors and includes lags in financial reporting of up to one quarter.

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
Current assets	$ 521	$ 892	$ 732
Noncurrent assets	$ 1,859	$ 4,225	$ 5,175
Current liabilities	$ 192	$ 207	$ 277
Noncurrent liabilities	$ 1,468	$ 1,726	$ 1,916
Gross revenue	$ 1,807	$ 2,190	$ 2,209
Operating expense	$ 3,926	$ 3,089	$ 1,630
Net income (loss)	$ (2,459)	$ (968)	$ 494

14. Variable Interest Entities

We consolidate the activities of VIEs for which we are the primary beneficiary. 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 because (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, 2013, approximately $320 million of net natural gas and oil properties, $22 million of other current liabilities, $1 million of cash and cash equivalents and $5 million of short-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.

15. Other Property and Equipment

Other Property and Equipment

A summary of other property and equipment held for use and the useful lives thereof is as follows:

	December 31, 2013	December 31, 2012	Useful Life
	($ in millions)		(in years)
Oilfield services equipment	$ 2,192	$ 2,130	3 - 15
Buildings and improvements	1,433	1,580	10 - 39
Natural gas compressors	368	505	3 - 20
Land	212	515	—
Other	1,190	1,178	2 - 20
Total other property and equipment, at cost	5,395	5,908	
Less: accumulated depreciation	(1,584)	(1,293)	
Total other property and equipment, net	$ 3,811	$ 4,615	

Net Gains on Sales of Fixed Assets

A summary by asset class of (gains) or losses on sales of fixed assets for the years ended December 31, 2013, 2012 and 2011 is as follows:

	Years Ended December 31, 2013	2012	2011
	($ in millions)		
Gathering systems and treating plants	$ (326)	$ (286)	$ (440)
Drilling rigs and equipment	2	10	1
Buildings and land	27	7	2
Other	(5)	2	—
Total net gains on sales of fixed assets	$ (302)	$ (267)	$ (437)

Gathering Systems and Treating Plants. In 2013, CMD sold its wholly owned midstream subsidiary, Mid-America Midstream Gas Services, L.L.C. (MAMGS), to SemGas, L.P. (SemGas), a wholly owned subsidiary of SemGroup Corporation, for net proceeds of approximately $306 million, subject to post-closing adjustments. We recorded a $141 million gain associated with this transaction. MAMGS owns certain gathering and processing assets located in the Mississippi Lime play, and the transaction with SemGas included a new long-term fixed-fee gathering and processing agreement covering acreage dedication areas in the Mississippi Lime play.

In 2013, CMD sold its wholly owned subsidiary, Granite Wash Midstream Gas Services, L.L.C. (GWMGS), to MarkWest Oklahoma Gas Company, L.L.C., a wholly owned subsidiary of MarkWest Energy Partners, L.P. (NYSE:MWE), for net proceeds of approximately $252 million, subject to post-closing adjustments. We recorded a $105 million gain associated with this transaction. GWMGS owns certain midstream assets in the Anadarko Basin that service the Granite Wash and Hogshooter formations. The transaction with MWE included new long-term fixed-fee agreements for gas gathering, compression, treating and processing services.

In 2013, we sold our interest in certain gathering system assets in Pennsylvania to Western Gas Partners, LP (NYSE:WES) for proceeds of approximately $134 million. We recorded a $55 million gain associated with this transaction.

In 2012, 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. 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 gain associated with this transaction.

In 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 $3 million gain associated with this transaction. In connection with the sale, we entered into new gathering and transportation agreements covering acreage dedication areas.

In 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. We, and other producers in the area, have 15-year cost of service gathering and compression agreements with AMS that include acreage dedications and an annual fee redetermination.

Buildings and Land. In 2013, we recorded net losses of $27 million on sales of buildings and land located primarily in our Barnett Shale operating area.

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.

Assets and Liabilities Held for Sale

In 2013, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. In addition, as of December 31, 2013 we were continuing to pursue the sale of various land and buildings located in the Fort Worth, Texas area. The land and buildings in both the Oklahoma City and Fort Worth areas are reported under our other segment. We are also pursuing the sale of various other property and equipment, including certain drilling rigs, compressors and gathering systems. The drilling rigs are reported under our oilfield services operating segment, and the compressors and gathering systems are reported under our marketing, gathering and compression operating segment. These assets are being actively marketed, and we believe it is probable they will be sold over the next 12 months. As a result, these assets qualified as held for sale as of December 31, 2013. 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 sheets as of December 31, 2013 and 2012 is detailed below.

	December 31,	
	2013	2012
	($ in millions)	
Accounts receivable	$ —	$ 4
Current assets held for sale	$ —	$ 4
Natural gas gathering systems and treating plants, net of accumulated depreciation	$ 11	$ 352
Oilfield services equipment, net of accumulated depreciation	29	27
Compressors, net of accumulated depreciation	285	—
Buildings and land, net of accumulated depreciation	405	255
Property and equipment held for sale, net	$ 730	$ 634
Accounts payable	$ —	$ 4
Accrued liabilities	—	17
Current liabilities held for sale	$ —	$ 21

16. Impairments

Impairment of Natural Gas and Oil Properties

We 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, referred to as a ceiling test, is described in Note 1 under *Natural Gas and Oil Properties*. In 2012, capitalized costs of natural gas and oil properties exceeded the ceiling, resulting in an impairment in the carrying value of natural gas and oil properties of $3.315 billion. Cash flow hedges as of September 30, 2012, which related to future periods, increased the ceiling test impairment by $279 million. We were not required to record impairments of natural gas and oil properties for any other quarter in 2012 or for any quarters in 2011 or 2013.

Impairments of Fixed Assets and Other

A summary of our impairments of fixed assets by asset class and other charges for the years ended December 31, 2013, 2012 and 2011 is as follows:

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
Buildings and land	$ 366	$ 248	$ 3
Drilling rigs and equipment	71	60	—
Gathering systems	22	6	43
Other	87	26	—
Total impairments of fixed assets and other	$ 546	$ 340	$ 46

Buildings and Land. In 2013, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. Some of these assets have been actively marketed and we believe it is probable they will be sold over the next 12 months. As a result, these assets qualified as held for sale as of December 31, 2013. We recognized an impairment loss of $186 million during 2013 on these assets for the difference between the carrying amount and fair value of the assets, less the anticipated costs to sell. See *Assets and Liabilities Held for Sale* in Note 15. We measured the fair value of these assets based on prices from orderly sales transactions for comparable properties between market participants, discounted cash flows or purchase offers we received from third parties.

Given the impairment losses associated with these assets, in 2013 we tested other noncore buildings and land that we own in the Oklahoma City area for recoverability. Our estimate of the future undiscounted cash flows for these assets was less than their carrying amounts, and we recognized an additional impairment loss of $69 million on these assets for the difference between the carrying amount and fair value of the assets. We measured the fair value of these assets based on prices from orderly sales transactions for comparable properties between market participants and, in certain cases, discounted cash flows.

Due to a decrease in the estimated market prices of certain surface land classified as held for sale in the Fort Worth, Texas area, we recognized an additional impairment loss of $86 million in 2013. We measured the fair value of these assets based on recent prices from orderly sales transactions for comparable properties between market participants. In addition, we tested other noncore surface land that we own in the Fort Worth area for recoverability in 2013 and recognized an additional impairment loss of $10 million on these assets for the difference between the carrying amount and fair value of the assets. In 2012, we recognized $248 million of impairment losses associated with an office building and surface land located in our Barnett Shale operating area. The change in business climate in the Barnett Shale in 2012, evidenced by our significant reduction in Barnett Shale operations and depressed natural gas prices, required us to test these long-lived assets for recoverability. We received 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.

Finally, we recorded an impairment loss of approximately $15 million on certain of our buildings and land outside of the Oklahoma City and Fort Worth areas in 2013. All the buildings and land for which impairment losses were recognized in 2013, 2012 and 2011 are included in our other segment.

Drilling Rigs and Equipment. In 2013, we negotiated the purchase of 23 leased rigs (two of which were classified as held for sale assets as of December 31, 2013) from various lessors for an aggregate purchase price of $141 million and paid approximately $22 million in early lease termination costs, which is included in impairments of fixed assets and other in the consolidated statement of operations. In addition, we impaired approximately $22 million of leasehold improvements and other costs associated with these transactions. See Note 4 for a description of the master lease agreements. In addition, in 2013, we recognized $27 million of impairment losses on certain of our drilling rigs that qualified as held for sale during 2013 for the difference between the carrying amount and fair value, less the anticipated costs to sell. We estimated the fair value using prices expected to be received. In 2012, we negotiated the purchase of 25 leased rigs from various lessors for an aggregate purchase price of $36 million and paid approximately $25 million in early lease termination costs, which is included in impairments of fixed assets and other in the consolidated statement of operations. In addition, in 2012, we recognized $26 million of impairment losses on certain of our drilling rigs that we expected would have insufficient cash flow to recover carrying values because of a change in business climate resulting from depressed natural gas prices. We estimated the fair value of the drilling rigs using prices expected to be received from the sale of 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 oilfield services equipment. The drilling rigs and equipment are included in our oilfield services operating segment.

Gathering Systems. In 2013, 2012 and 2011, we recognized approximately $22 million, $6 million and $43 million, respectively, of impairment losses on certain of our gathering systems classified as held for sale as of December 31, 2013 and 2012 based on decreases in the estimated fair value of these assets. We estimated the fair value of the gathering systems using prices expected to be received from the sale of each gathering system in an orderly transaction between market participants. These gathering systems are included in our marketing, gathering and compression operating segment.

Other. In 2013, we recorded approximately $87 million of other charges, including $26 million for the termination of a gas gathering agreement, $28 million for the impairment of certain assets used to promote natural gas demand, $15 million for the termination of a contract drilling agreement with a third party, $2 million related to the estimated 2012 shortfall of our net acreage maintenance commitment with Total in the Barnett Shale and $16 million related to various other assets. In 2012, we recorded a $26 million charge related to the estimated 2012 shortfall of our net acreage maintenance commitment with Total in the Barnett Shale. See *Commitments - Net Acreage Maintenance Commitment*s in Note 4 for further discussion.

17. Restructuring and Other Termination Costs

On September 9, 2013, we committed to a workforce reduction plan as part of a company-wide reorganization effort intended to reduce costs. The reduction was communicated to affected employees on various dates within the months of September and October, and all such notifications were completed by October 11, 2013. The plan resulted in a reduction of approximately 900 employees. In connection with the reduction, we incurred a total cost of approximately $66 million.

On April 1, 2013, Aubrey K. McClendon, the co-founder of the Company, ceased serving as President and CEO and as a director of the Company pursuant to his agreement with the Board of Directors announced on January 29, 2013. Mr. McClendon's departure from the Company was treated as a termination without cause under his employment agreement. On April 18, 2013, the Company and Mr. McClendon entered into a Founder Separation and Services Agreement, effective January 29, 2013, regarding his separation from employment and to facilitate the relationship between the Company and Mr. McClendon as joint working interest owners of oil and gas wells, leases and acreage. See Note 7 regarding Mr. McClendon's historical participation in our drilling activities. In 2013, we incurred charges of approximately $69 million related to Mr. McClendon's departure.

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, and 211 accepted prior to the expiration of the offer in February 2013. We recognized the expense related to their termination benefits over their remaining service period which resulted in $63 million of expense for 2013.

During 2013, we also incurred charges of approximately $50 million related to other workforce reductions, including separations of executive officers other than the CEO.

Substantially all of the restructuring and other termination costs in 2013 are in the exploration and production operating segment. Below is a summary of our restructuring and other termination costs for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
		($ in millions)	
Restructuring charges under workforce reduction plan:			
Salary expense	$ 20	$ —	$ —
Acceleration of stock-based compensation	45	—	—
Other termination benefits	1	—	—
Total restructuring charges under workforce reduction plan	66	—	—
Termination benefits provided to Mr. McClendon:			
Salary and bonus expense	11	—	—
Acceleration of 2008 performance bonus clawback	11	—	—
Acceleration of stock-based compensation	22	—	—
Acceleration of performance share unit awards	18	—	—
Estimated aircraft usage benefits	7	—	—
Total termination benefits provided to Mr. McClendon	69	—	—
Termination benefits provided to VSP participants:			
Salary and bonus expense	33	1	—
Acceleration of stock-based compensation	29	1	—
Other termination benefits	1	—	—
Total termination benefits provided to VSP participants	63	2	—
Other termination benefits	50	5	—
Total restructuring and other termination costs	$ 248	$ 7	$ —

18. Fair Value Measurements

Recurring Fair Value Measurement

Other Current Assets. Assets related to forfeited Company matches of employee contributions to Chesapeake's employee benefit plans are included in other current assets. The fair value of these assets is determined using quoted market prices as they consist of exchange-traded securities.

Investments. The fair value of Chesapeake's investments in Clean Energy and Gastar common stock was based on quoted market prices.

Other Current Liabilities. Liabilities related to Chesapeake's deferred compensation plan are included in other current liabilities. The fair values of these liabilities are determined using quoted market prices, as the plan consists of exchange-traded mutual funds.

Derivatives. The fair value of most 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 compared to the values given by our counterparties for reasonableness. Since natural gas, oil, 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.

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2013 and 2012:

As of December 31, 2013	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	$ 80	$ —	$ —	$ 80
Other current liabilities	(82)	—	—	(82)
Derivatives:				
Commodity assets	—	25	15	40
Commodity liabilities	—	(100)	(493)	(593)
Interest rate liabilities	—	(98)	—	(98)
Foreign currency liabilities	—	2	—	2
Total derivatives	—	(171)	(478)	(649)
Total	$ (2)	$ (171)	$ (478)	$ (651)

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)

A summary of the changes in Chesapeake's financial assets (liabilities) classified as Level 3 measurements during 2013 and 2012 is presented below.

	Derivatives	
	Commodity	Interest Rate
	($ in millions)	
Beginning Balance as of January 1, 2013	$ (1,016)	$ —
Total gains (losses) (realized/unrealized):		
Included in earnings[a]	410	(1)
Total purchases, issuances, sales and settlements:		
Sales	—	1
Settlements	128	—
Ending Balance as of December 31, 2013	$ (478)	$ —
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)	$ —

(a)

	Natural Gas, Oil and NGL Sales		Interest Expense	
	2013	2012	2013	2012
	($ in millions)			
Total gains (losses) included in earnings for the period	$ 410	$ 567	$ (1)	$ 6
Change in unrealized gains (losses) related to assets still held at reporting date	$ 382	$ 374	$ —	$ —

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 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 decreases (increases) the fair value of natural gas and oil derivatives and adverse changes to our counterparties' creditworthiness decreases 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, 2013
				($ in millions)
Oil trades[(a)]	Oil price volatility curves	0% - 23.65%	13.62%	$ (265)
Oil basis swaps[(b)]	Physical pricing point forward curves	$3.51 - $4.41	$ 3.74	$ 1
Natural gas trades[(a)]	Natural gas price volatility curves	17.75% - 60.88%	22.49%	$ (217)
Natural gas basis swaps[(b)]	Physical pricing point forward curves	($1.03) - ($0.11)	$ (0.46)	$ 3

(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

In 2013, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. Fair value measurements were applied with respect to these non-financial assets, measured on a nonrecurring basis, to determine impairments. We used the income approach, specifically discounted cash flows, for income-producing assets and the market approach for the remaining assets. As the fair values estimated using the market approach were based on recent prices from orderly sales transactions for comparable properties between market participants, the values of these properties are classified as Level 2. The discounted cash flow method includes the development of both current operating metrics as well as assumptions pertaining to the subsequent change of such metrics, including rent growth, operating expense growth and absorption. These assumptions are applied to a specified period to develop future cash flow projections that are then discounted to estimate fair value. Due to these assumptions, the values of these properties are classified as Level 3.

Due to a decrease in the estimated market prices of certain surface land classified as held for sale in the Fort Worth, Texas area, we recognized an additional impairment loss in 2013. Fair value measurements were applied with respect to these non-financial assets, measured on a nonrecurring basis, to determine impairments. We measured the fair value of these assets by obtaining the current list price, if marketed for sale, or comparable list prices from similar properties in the area. The list prices were based on and adjusted for review of market data for comparable properties, where available, review of aerial or survey information, and assessment of other property and market-related factors. These list prices are estimates and are subject to changing market conditions. Should market conditions change adversely in the future, this could result in additional impairment or result in proceeds received upon sale to materially differ from the current estimate. See Note 16 for further discussion of the impairments recorded.

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 loan, 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, 2013		December 31, 2012	
	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)	$ 10,501	$ 11,557	$ 9,759	$ 10,457
Long-term debt (Level 2)	$ 2,372	$ 2,369	$ 2,378	$ 2,284

19. Asset Retirement Obligations

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

	Years Ended December 31,	
	2013	2012
	($ in millions)	
Asset retirement obligations, beginning of period	$ 375	$ 323
Additions	20	29
Revisions[(a)]	8	42
Settlements and disposals	(20)	(41)
Accretion expense	22	22
Asset retirement obligations, end of period	$ 405	$ 375

(a) Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives, and the expected timing of settlement.

20. Major Customers and Segment Information

There were no sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) for the years ended December 31, 2013 and 2011. Sales to Plains Marketing, L.P. constituted 11% of our total revenues (before the effects of hedging) for the year ended December 31, 2012.

We have three reportable operating segments, each of which is managed separately because of the nature of its 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. The oilfield services operating segment is responsible for drilling, oilfield trucking, oilfield rentals, hydraulic fracturing and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties.

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 revenues within our exploration and production operating segment. Such amounts totaled $7.570 billion, $5.464 billion and $5.246 billion for the years ended December 31, 2013, 2012 and 2011, respectively. Revenues generated by the oilfield services operating segment for work performed for Chesapeake's exploration and production operating segment are reclassified to the full cost pool based on Chesapeake's ownership interest. Revenues reclassified totaled $1.309 billion, $1.315 billion and $737 million for the years ended December 31, 2013, 2012 and 2011, respectively. No income is recognized in our consolidated statements of operations related to oilfield services performed for Chesapeake-operated wells. The following table presents selected financial information for Chesapeake's operating segments:

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
			($ in millions)			
Year Ended December 31, 2013:						
Revenues	$ 7,052	$ 17,129	$ 2,188	$ 29	$ (8,892)	$ 17,506
Intersegment revenues	—	(7,570)	(1,309)	(13)	8,892	—
Total revenues	$ 7,052	$ 9,559	$ 879	$ 16	$ —	$ 17,506
Unrealized gains on commodity derivatives	(228)	—	—	—	—	(228)
Natural gas, oil, NGL and other depreciation, depletion and amortization	2,674	46	289	49	(155)	2,903
(Gains) losses on sales of fixed assets	2	(329)	(1)	26	—	(302)
Impairments of fixed assets and other	27	50	75	394	—	546
Interest expense	(918)	(24)	(82)	(74)	871	(227)
Earnings (losses) on investments	3	—	(1)	(229)	1	(226)
Losses on sales of investments	—	—	—	(7)	—	(7)
Losses on purchases of debt and extinguishment of other financing	(193)	—	—	—	—	(193)
Income (Loss) Before Income Taxes	$ 2,997	$ 511	$ (51)	$ (727)	$ (1,288)	1,442
Total Assets	$ 35,341	$ 2,430	$ 2,018	$ 5,750	$ (3,757)	$ 41,782
Capital Expenditures	$ 6,198	$ 299	$ 272	$ 421	$ —	$ 7,190

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)					
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 gains on commodity derivatives	(561)	—	—	—	—	(561)
Natural gas, oil, NGL and other depreciation, depletion and amortization	2,624	54	232	46	(145)	2,811
Impairment of natural gas and oil properties	3,315	—	—	—	—	3,315
Impairments of fixed assets and other	28	6	60	246	—	340
(Gains) losses on sales of fixed assets	14	(298)	10	7	—	(267)
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 of debt and extinguishment of other financing	(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	Intercompany Eliminations	Consolidated Total
			($ in millions)			
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 losses on commodity derivatives	789	—	—	—	—	789
Natural gas, oil, NGL and other depreciation, depletion and amortization	1,759	55	172	37	(100)	1,923
Impairments of fixed assets and other	—	43	3	—	—	46
(Gains) losses on sales of fixed assets	3	(441)	1	—	—	(437)
Interest expense	(42)	(15)	(48)	(195)	256	(44)
Earnings on investments	—	95	—	61	—	156
Losses on purchases of debt and extinguishment of other financing	(176)	—	—	—	—	(176)
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

21. 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 100% owned subsidiaries on a senior unsecured basis. Our oilfield services subsidiary, COS, and its subsidiaries are separately capitalized and are not guarantors of our senior notes or our other debt obligations, 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. In addition, subsidiaries with noncontrolling interests, consolidated variable interest entities and certain de minimis subsidiaries are 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, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011. Such financial information may not necessarily be indicative of our results of operations, cash flows or financial position had these subsidiaries operated as independent entities. Certain prior year information has been restated for subsidiaries that have changed between guarantor and non-guarantor during 2013.

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 799	$ —	$ 39	$ (1)	$ 837
Restricted cash	—	—	82	(7)	75
Other	103	2,395	613	(367)	2,744
Current assets held for sale	—	—	—	—	—
Intercompany receivable, net	25,385	—	—	(25,385)	—
Total Current Assets	26,287	2,395	734	(25,760)	3,656
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net	—	29,295	3,113	185	32,593
Other property and equipment, net	—	2,317	1,495	(1)	3,811
Property and equipment held for sale, net	—	701	29	—	730
Total Property and Equipment, Net	—	32,313	4,637	184	37,134
LONG-TERM ASSETS:					
Other assets	111	1,146	111	(376)	992
Investments in subsidiaries and intercompany advances	2,333	(235)	—	(2,098)	—
TOTAL ASSETS	$ 28,731	$ 35,619	$ 5,482	$ (28,050)	$ 41,782
CURRENT LIABILITIES:					
Current liabilities	$ 300	$ 5,196	$ 378	$ (359)	$ 5,515
Intercompany payable, net	—	24,814	474	(25,288)	—
Total Current Liabilities	300	30,010	852	(25,647)	5,515
LONG-TERM LIABILITIES:					
Long-term debt, net	11,831	—	1,055	—	12,886
Deferred income tax liabilities	209	2,254	857	87	3,407
Other long-term liabilities	396	1,022	877	(461)	1,834
Total Long-Term Liabilities	12,436	3,276	2,789	(374)	18,127
EQUITY:					
Chesapeake stockholders' equity	15,995	2,333	1,841	(4,174)	15,995
Noncontrolling interests	—	—	—	2,145	2,145
Total Equity	15,995	2,333	1,841	(2,029)	18,140
TOTAL LIABILITIES AND EQUITY	$ 28,731	$ 35,619	$ 5,482	$ (28,050)	$ 41,782

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2012
($ in millions)

	Parent[(a)]	Guarantor Subsidiaries[(a)]	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 228	$ —	$ 59	$ —	$ 287
Restricted cash	—	—	111	—	111
Other	1	2,382	511	(348)	2,546
Current assets held for sale	—	—	4	—	4
Intercompany receivable, net	25,159	—	—	(25,159)	—
Total Current Assets	25,388	2,382	685	(25,507)	2,948
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net	—	28,742	3,387	(211)	31,918
Other property and equipment, net	—	3,065	1,551	(1)	4,615
Property and equipment held for sale, net	—	256	378	—	634
Total Property and Equipment, Net	—	32,063	5,316	(212)	37,167
LONG-TERM ASSETS:					
Other assets	217	1,396	261	(378)	1,496
Investments in subsidiaries and intercompany advances	2,438	(134)	—	(2,304)	—
TOTAL ASSETS	$ 28,043	$ 35,707	$ 6,262	$ (28,401)	$ 41,611
CURRENT LIABILITIES:					
Current liabilities	$ 789	$ 5,377	$ 428	$ (349)	$ 6,245
Current liabilities held for sale	—	—	21	—	21
Intercompany payable, net	—	23,684	1,586	(25,270)	—
Total Current Liabilities	789	29,061	2,035	(25,619)	6,266
LONG-TERM LIABILITIES:					
Long-term debt, net	11,089	—	1,068	—	12,157
Deferred income tax liabilities	361	2,425	127	(106)	2,807
Other liabilities	235	1,783	839	(372)	2,485
Total Long-Term Liabilities	11,685	4,208	2,034	(478)	17,449
EQUITY:					
Chesapeake stockholders' equity	15,569	2,438	2,193	(4,631)	15,569
Noncontrolling interests	—	—	—	2,327	2,327
Total Equity	15,569	2,438	2,193	(2,304)	17,896
TOTAL LIABILITIES AND EQUITY	$ 28,043	$ 35,707	$ 6,262	$ (28,401)	$ 41,611

(a) We have revised the amounts presented as cash and cash equivalents in the Guarantor Subsidiaries and Parent columns to properly reflect the cash of the Parent of $228 million, which was incorrectly presented in the Guarantor Subsidiaries column. The impact of this error was not material to any previously issued financial statements.

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AS OF DECEMBER 31, 2013 ($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$ —	$ 6,289	$ 754	$ 9	$ 7,052
Marketing, gathering and compression	—	9,549	10	—	9,559
Oilfield services	—	—	2,218	(1,323)	895
Total Revenues	—	15,838	2,982	(1,314)	17,506
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	1,099	60	—	1,159
Production taxes	—	221	8	—	229
Marketing, gathering and compression	—	9,456	5	—	9,461
Oilfield services	—	95	1,761	(1,120)	736
General and administrative	—	361	97	(1)	457
Restructuring and other termination costs	—	244	4	—	248
Natural gas, oil and NGL depreciation, depletion and amortization	—	2,303	286	—	2,589
Depreciation and amortization of other assets	—	177	292	(155)	314
Impairment of natural gas and oil properties	—	—	311	(311)	—
Impairments of fixed assets and other	—	443	103	—	546
Net gains on sales of fixed assets	—	(301)	(1)	—	(302)
Total Operating Expenses	—	14,098	2,926	(1,587)	15,437
INCOME (LOSS) FROM OPERATIONS	—	1,740	56	273	2,069
OTHER INCOME (EXPENSE):					
Interest expense	(921)	(4)	(85)	783	(227)
Losses on investments	—	(225)	(1)	—	(226)
Losses on sales of investments	—	(7)	—	—	(7)
Losses on purchases of debt and extinguishment of other financing	(70)	(123)	—	—	(193)
Other income (loss)	3,979	(594)	13	(3,372)	26
Equity in net earnings of subsidiary	(1,129)	(264)	—	1,393	—
Total Other Income (Expense)	1,859	(1,217)	(73)	(1,196)	(627)
INCOME (LOSS) BEFORE INCOME TAXES	1,859	523	(17)	(923)	1,442
INCOME TAX EXPENSE (BENEFIT)	1,135	299	(6)	(880)	548
NET INCOME (LOSS)	724	224	(11)	(43)	894
Net income attributable to noncontrolling interests	—	—	—	(170)	(170)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	724	224	(11)	(213)	724
Other comprehensive income (loss)	3	19	(2)	—	20
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 727	$ 243	$ (13)	$ (213)	$ 744

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	$ —	$ 5,819	$ 387	$ 72	$ 6,278
Marketing, gathering and compression	—	5,370	212	(151)	5,431
Oilfield services	—	—	1,941	(1,334)	607
Total Revenues	—	11,189	2,540	(1,413)	12,316
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	1,275	29	—	1,304
Production taxes	—	182	6	—	188
Marketing, gathering and compression	—	5,284	115	(87)	5,312
Oilfield services	—	168	1,433	(1,136)	465
General and administrative	—	415	121	(1)	535
Restructuring and other termination costs	—	5	2	—	7
Natural gas, oil and NGL depreciation, depletion and amortization	—	2,346	161	—	2,507
Depreciation and amortization of other assets	—	181	273	(150)	304
Impairment of natural gas and oil properties	—	3,174	141	—	3,315
Impairments of fixed assets and other	—	275	65	—	340
Net gains on sales of fixed assets	—	(269)	2	—	(267)
Total Operating Expenses	—	13,036	2,348	(1,374)	14,010
INCOME (LOSS) FROM OPERATIONS	—	(1,847)	192	(39)	(1,694)
OTHER INCOME (EXPENSE):					
Interest expense	(879)	45	(84)	841	(77)
Losses on investments	—	(167)	55	9	(103)
Gains on sales of investments	—	1,030	62	—	1,092
Losses on purchases of debt and extinguishment of other financing	(200)	—	—	—	(200)
Other income	819	202	15	(1,028)	8
Equity in net earnings (losses) of subsidiary	(610)	(163)	—	773	—
Total Other Income (Expense)	(870)	947	48	595	720
INCOME (LOSS) BEFORE INCOME TAXES	(870)	(900)	240	556	(974)
INCOME TAX EXPENSE (BENEFIT)	(101)	(287)	93	(85)	(380)
NET INCOME (LOSS)	(769)	(613)	147	641	(594)
Net income attributable to noncontrolling interests	—	—	—	(175)	(175)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(769)	(613)	147	466	(769)
Other comprehensive income (loss)	6	(22)	—	—	(16)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ (763)	$ (635)	$ 147	$ 466	$ (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	—	5,022	199	(131)	5,090
Oilfield services	—	18	1,260	(757)	521
Total Revenues	—	10,926	1,543	(834)	11,635
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	1,073	—	—	1,073
Production taxes	—	190	2	—	192
Marketing, gathering and compression	—	4,944	116	(93)	4,967
Oilfield services	—	1	958	(557)	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
Impairments of fixed assets and other	—	—	46	—	46
Net gains on sales of fixed assets	—	(2)	(435)	—	(437)
Total Operating Expenses	—	8,477	982	(745)	8,714
INCOME (LOSS) FROM OPERATIONS	—	2,449	561	(89)	2,921
OTHER INCOME (EXPENSE):					
Interest expense	(640)	(12)	(50)	658	(44)
Earnings (losses) on investments	—	61	95	—	156
Losses on purchases of debt and extinguishment of other financing	(176)	—	—	—	(176)
Other income	646	43	19	(685)	23
Equity in net earnings of subsidiary	1,846	309	—	(2,155)	—
Total Other Income (Expense)	1,676	401	64	(2,182)	(41)
INCOME (LOSS) BEFORE INCOME TAXES	1,676	2,850	625	(2,271)	2,880
INCOME TAX EXPENSE (BENEFIT)	(66)	991	243	(45)	1,123
NET INCOME (LOSS)	1,742	1,859	382	(2,226)	1,757
Net income attributable to noncontrolling interests	—	—	—	(15)	(15)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,742	1,859	382	(2,241)	1,742
Other comprehensive income	9	(9)	2	—	2
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 1,751	$ 1,850	$ 384	$ (2,241)	$ 1,744

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 4,115	$ 542	$ (43)	$ 4,614
CASH FLOWS FROM INVESTING ACTIVITIES:					
Acquisitions of proved and unproved properties	—	(6,226)	(410)	—	(6,636)
Proceeds from divestitures of proved and unproved properties	—	3,414	53	—	3,467
Additions to other property and equipment	—	(581)	(391)	—	(972)
Other investing activities	—	117	765	292	1,174
Net Cash Used In Investing Activities	—	(3,276)	17	292	(2,967)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	6,452	1,217	—	7,669
Payments on credit facilities borrowings	—	(6,452)	(1,230)	—	(7,682)
Proceeds from issuance of senior notes, net of discount and offering costs	2,274	—	—	—	2,274
Cash paid to purchase debt	(2,141)	—	—	—	(2,141)
Proceeds from sales of noncontrolling interests	—	—	6	—	6
Other financing activities	1,819	(2,809)	17	(250)	(1,223)
Intercompany advances, net	(1,381)	1,970	(589)	—	—
Net Cash Provided By (Used In) Financing Activities	571	(839)	(579)	(250)	(1,097)
Net increase (decrease) in cash and cash equivalents	571	—	(20)	(1)	550
Cash and cash equivalents, beginning of period	228	—	59	—	287
Cash and cash equivalents, end of period	$ 799	$ —	$ 39	$ (1)	$ 837

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2012
($ in millions)

	Parent[(a)]	Guarantor Subsidiaries[(a)]	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 3,662	$ 431	$ (1,256)	$ 2,837
CASH FLOWS FROM INVESTING ACTIVITIES:					
Acquisitions of proved and unproved properties	—	(11,099)	(992)	—	(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	—	4,705	2,133	(2,964)	3,874
Net Cash Used In Investing Activities	—	(1,666)	(354)	(2,964)	(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 senior notes, net of discount and offering costs	1,263	—	—	—	1,263
Proceeds from issuance of term loans, net of discount and offering costs	5,722	—	—	—	5,722
Cash paid to purchase debt	(4,000)	—	—	—	(4,000)
Proceeds from sales of noncontrolling interests	—	—	1,077	—	1,077
Other financing activities	(477)	(153)	(4,237)	4,220	(647)
Intercompany advances, net	(2,282)	(123)	2,405	—	—
Net Cash Provided By (Used In) Financing Activities	226	(1,996)	(367)	4,220	2,083
Net increase 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

(a) We have revised the amounts presented as cash and cash equivalents in the Guarantor Subsidiaries and Parent columns to properly reflect the cash of the Parent of $228 million, which was incorrectly presented in the Guarantor Subsidiaries column. The impact of this error was not material to any previously issued financial statements.

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

	Parent[(a)]	Guarantor Subsidiaries[(a)]	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 5,868	$ 438	$ (403)	$ 5,903
CASH FLOWS FROM INVESTING ACTIVITIES:					
Acquisitions of 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
Net 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	1,533	(1,751)	218	—	—
Net Cash Provided By (Used In) Financing Activities	1	(2,231)	2,601	(213)	158
Net increase 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

(a) We have revised the amounts presented as cash and cash equivalents in the Guarantor Subsidiaries and Parent columns to properly reflect the cash of the Parent of $2 million which was incorrectly presented in the Guarantor Subsidiaries column. The impact of this error was not material to any previously issued financial statements.

22. Recently Issued Accounting Standards

Recently Adopted Accounting Standards

In February 2012, the Financial Accounting Standards Board (FASB) issued guidance changing the presentation requirements of significant reclassifications out of accumulated other comprehensive income in their entirety and their corresponding effect on net income. We adopted this standard in the first quarter of 2013 and it did not have a material impact on our financial statements.

In December 2011 and January 2013, the FASB issued guidance amending and expanding disclosure requirements about offsetting and related arrangements associated with derivatives. We adopted this standard in the first quarter of 2013 and it did not have a material impact on our financial statements.

Recently Issued Accounting Standards

To reduce diversity in practice related to the presentation of unrecognized tax benefits, in July 2013 the FASB issued guidance requiring the presentation of an unrecognized tax benefit in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward. This net presentation is required unless a net operating loss carryforward, a similar tax loss or a tax credit carryforward is not available at the reporting date or the tax law of the jurisdiction does not require, and the entity does not intend to use, the deferred tax asset to settle any additional income tax that would result from the disallowance of the unrecognized tax benefit. The guidance will be effective on January 1, 2014; retrospective application and early adoption are permitted, but not required. Because we have historically presented unrecognized tax benefits net of net operating loss carryforwards, similar tax losses or tax credit carryforwards, this standard will not impact our consolidated financial statements.

In February 2013, the FASB issued guidance on the recognition, measurement and disclosure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. We will adopt this standard effective January 1, 2014. We do not expect the adoption to have a material impact on our consolidated financial statements.

23. Subsequent Events

On January 13, 2014, we sold our investment in Chaparral Energy, Inc. for cash proceeds of $215 million.

Subsequent to December 31, 2013, we acquired ten rigs subject to the master lease agreements described in Note 4. In conjunction with the purchases, we also terminated approximately $9 million of remaining lease commitments associated with these rigs. Total consideration paid was approximately $31 million and we anticipate recording a charge in the 2014 first quarter for lease termination cost.

Subsequent to December 31, 2013, we acquired 576 compressors subject to the master lease agreements described in Note 4. In conjunction with these purchases, we also terminated approximately $126 million of remaining lease commitments associated with these compressors. Total consideration paid was approximately $168 million.

Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2013 and 2012 are as follows:

	Quarters Ended			
	March 31, 2013	June 30, 2013	September 30, 2013	December 31, 2013
	($ in millions except per share data)			
Total revenues	$ 3,424	$ 4,675	$ 4,867	$ 4,541
Gross profit[a]	$ 217	$ 1,167	$ 436	$ 249
Net income (loss) attributable to Chesapeake[b]	$ 58	$ 580	$ 202	$ (116)
Net income (loss) available to common stockholders[b]	$ 15	$ 458	$ 156	$ (159)
Net earnings (loss) per common share:				
Basic	$ 0.02	$ 0.70	$ 0.24	$ (0.24)
Diluted	$ 0.02	$ 0.66	$ 0.24	$ (0.24)

	Quarters Ended			
	March 31, 2012	June 30, 2012	September 30, 2012	December 31, 2012
	($ in millions except per share data)			
Total revenues	$ 2,419	$ 3,389	$ 2,970	$ 3,538
Gross profit (loss)[a][c]	$ 6	$ 738	$ (3,194)	$ 756
Net income (loss) attributable to Chesapeake[c]	$ (28)	$ 972	$ (2,012)	$ 299
Net income (loss) available to common stockholders[c]	$ (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

(a) Total revenue less operating expenses.
(b) Includes $203 million of impairments of fixed assets and other and $123 million of losses on the extinguishment of other financing for the quarter ended December 31, 2013. See Note 16 and Note 5 for further discussion.
(c) Includes a $3.315 billion ceiling test write-down on our natural gas and oil properties for the quarter ended September 30, 2012.

Supplemental Disclosures About Natural Gas, Oil and NGL Producing Activities (unaudited)

Net Capitalized Costs

Capitalized costs related to Chesapeake's natural gas, oil and NGL producing activities are summarized as follows:

	December 31,	
	2013	2012
	($ in millions)	
Natural gas and oil properties:		
Proved	$ 56,157	$ 50,172
Unproved	12,013	14,755
Total	68,170	64,927
Less accumulated depreciation, depletion and amortization	(35,577)	(33,009)
Net capitalized costs	$ 32,593	$ 31,918

Unproved properties not subject to amortization at December 31, 2013, 2012 and 2011 consisted mainly of leasehold acquired through direct purchases of significant natural gas and oil property interests. We capitalized approximately $815 million, $976 million and $727 million of interest during 2013, 2012 and 2011, 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,		
	2013	2012	2011
		($ in millions)	
Acquisitions of properties:			
Proved properties	$ 22	$ 332	$ 48
Unproved properties	997	2,981	4,736
Exploratory costs	699	2,353	2,261
Development costs	4,888	6,733	5,497
Costs incurred[(a)(b)]	$ 6,606	$ 12,399	$ 12,542

(a) Exploratory and development costs are net of joint venture drilling and completion cost carries of $884 million, $784 million and $2.570 billion in 2013, 2012 and 2011, respectively.

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

Capitalized interest	$ 815	$ 976	$ 727
Asset retirement obligations	$ 7	$ 32	$ 3

In 2013, we invested approximately $1.472 billion, net of drilling and completion cost carries of $79 million, to convert 169 mmboe 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 2013, 2012 and 2011. 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 indirect 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,		
	2013	2012	2011
		($ in millions)	
Natural gas, oil and NGL sales	$ 7,052	$ 6,278	$ 6,024
Natural gas, oil and NGL production expenses	(1,159)	(1,304)	(1,073)
Production taxes	(229)	(188)	(192)
Impairment of natural gas and oil properties	—	(3,315)	—
Depletion and depreciation	(2,589)	(2,507)	(1,632)
Imputed income tax provision[(a)]	(1,169)	404	(1,220)
Results of operations from natural gas, oil and NGL producing activities	$ 1,906	$ (632)	$ 1,907

(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, 2013, 2012 and 2011. Independent petroleum engineering firms estimated an aggregate of 81%, 89% and 77% of our estimated proved reserves (by volume) as of December 31, 2013, 2012 and 2011, respectively, as set forth below.

	December 31,		
	2013	2012	2011
Ryder Scott Company, L.P.	51%	44%	19%
PetroTechnical Services, Division of Schlumberger Technology Corporation	30%	24%	7%
Netherland, Sewell & Associates, Inc.	—%	21%	42%
Lee Keeling and Associates, Inc.	—%	—%	9%

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. 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 2013, 2012 and 2011.

	Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (mmboe)
December 31, 2013				
Proved reserves, beginning of period	10,933	495.5	297.3	2,615
Extensions, discoveries and other additions	2,160	96.3	68.0	524
Revisions of previous estimates	388	(61.1)	(32.9)	(30)
Production	(1,095)	(41.1)	(20.9)	(244)
Sale of reserves-in-place	(657)	(66.4)	(13.1)	(189)
Purchase of reserves-in-place	5	0.6	0.6	2
Proved reserves, end of period[(a)]	11,734	423.8	299.0	2,678
Proved developed reserves:				
Beginning of period	7,174	162.9	132.1	1,491
End of period	8,584	201.3	177.1	1,809
Proved undeveloped reserves:				
Beginning of period	3,759	322.6	165.2	1,124
End of period[(b)]	3,150	222.5	121.9	869

	Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (mmboe)
December 31, 2012				
Proved reserves, beginning of period	15,515	291.6	253.9	3,132
Extensions, discoveries and other additions	3,317	374.0	139.4	1,065
Revisions of previous estimates	(6,080)	(67.5)	(47.3)	(1,127)
Production	(1,129)	(31.3)	(17.6)	(237)
Sale of reserves-in-place	(704)	(75.5)	(31.7)	(225)
Purchase of reserves-in-place	14	4.2	0.6	7
Proved reserves, end of period(c)	10,933	495.5	297.3	2,615
Proved developed reserves:				
Beginning of period	8,578	124.0	130.6	1,684
End of period	7,174	162.9	132.1	1,491
Proved undeveloped reserves:				
Beginning of period	6,937	167.6	123.3	1,447
End of period(b)	3,759	332.6	165.2	1,124
December 31, 2011				
Proved reserves, beginning of period	15,455	150.1	123.3	2,849
Extensions, discoveries and other additions	4,156	168.4	85.2	947
Revisions of previous estimates	(361)	(7.8)	60.6	(8)
Production	(1,004)	(17.0)	(14.7)	(199)
Sale of reserves-in-place	(2,754)	(2.6)	(1.2)	(462)
Purchase of reserves-in-place	23	0.5	0.7	5
Proved reserves, end of period(d)	15,515	291.6	253.9	3,132
Proved developed reserves:				
Beginning of period	8,246	84.2	64.0	1,524
End of period	8,578	124.0	130.6	1,684
Proved undeveloped reserves:				
Beginning of period	7,209	65.9	59.3	1,326
End of period(b)	6,937	167.6	123.3	1,447

(a) Includes 61 bcf of natural gas, 2 mmbbls of oil and 6 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, 30 bcf of natural gas, 1 mmbbls of oil and 3 mmbbls of NGL of which are attributable to the noncontrolling interest holders.

(b) As of December 31, 2013, 2012 and 2011, there were no PUDs that had remained undeveloped for five years or more.

(c) 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.

(d) 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.

During 2013, we acquired approximately 2 mmboe of proved reserves through purchases of natural gas and oil properties for consideration of $22 million, and we sold 189 mmboe of proved reserves for approximately $1.621 billion. During 2013, we recorded downward revisions of 30 mmboe to the December 31, 2012 estimates of our reserves. Included in the revisions were 162 mmboe of upward revisions resulting from higher natural gas, oil and NGL prices in 2013 and 192 mmboe of downward revisions resulting from changes to previous estimates. 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, 2013 were $3.67 per mcf and $96.82 per bbl before price differentials. Including the effect of price differential adjustments, the prices used in computing our reserves as of December 31, 2013 were $2.37 per mcf of natural gas, $95.89 per barrel of oil and $25.78 per barrel of NGL. Included in the non-price revisions were 355 mmboe of downward revisions to our estimated PUD reserves, offset by 163 mmboe of upward revisions for performance. Of the 355 mmboe of downward PUD revisions, 280 mmboe related primarily to revised well spacing in our core development area in the Marcellus Shale, the extension of our development plan beyond five years for locations outside the core of our Eagle Ford Shale acreage and the removal of PUDs with only marginally economic estimated production. The remaining 75 mmboe of downward revisions were primarily due to a reduction in estimated PUD reserves per well in the Mississippi Lime play.

During 2012, we acquired approximately 7 mmboe of proved reserves through purchases of natural gas and oil properties for consideration of $332 million, and we sold 225 mmboe of our proved reserves for approximately $2.381 billion. During 2012, we recorded downward revisions of 1.127 bboe to the December 31, 2011 estimates of our reserves. Included in the revisions were 902 mmboe of downward revisions resulting from lower natural gas prices in 2012 and 225 mmboe 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 non price-related revisions were primarily the result of our continued execution of our strategy to shift the Company's drilling focus from natural gas to liquids-rich areas and to drill in the "core of the core" of our acreage positions. As rigs were reallocated, PUDs were removed from various noncore areas resulting in downward revisions.

During 2011, we acquired approximately 5 mmboe of proved reserves through purchases of natural gas and oil properties for consideration of $48 million, and we sold 463 bboe 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 downward revisions of 8 mmboe to the December 31, 2010 estimates of our reserves. Included in the revisions were 46 mmboe of upward revisions to producing properties, offset by 56 mmboe of downward revisions associated with the deletion of PUDs no longer consistent with our development plans. In addition, we had 2 mmboe of upward 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.

Standardized Measure of Discounted Future Net Cash Flows

Accounting Standards Codification 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, 2013, 2012 and 2011 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,		
	2013	2012	2011
	($ in millions)		
Future cash inflows	$ 76,094 [a]	$ 73,754 [b]	$ 85,537 [c]
Future production costs	(18,196)	(18,809)	(23,022)
Future development costs	(9,563)	(12,656)	(14,471)
Future income tax provisions	(12,196)	(9,824)	(12,266)
Future net cash flows	36,139	32,465	35,778
Less effect of a 10% discount factor	(18,749)	(17,799)	(20,148)
Standardized measure of discounted future net cash flows[d]	$ 17,390	$ 14,666	$ 15,630

(a) Calculated using prices of $3.67 per mcf of natural gas and $96.82 per bbl of oil, before field differentials.

(b) Calculated using prices of $2.76 per mcf of natural gas and $94.84 per bbl of oil, before field differentials.

(c) Calculated using prices of $4.12 per mcf of natural gas and $95.97 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 12.

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

	Years Ended December 31,		
	2013	2012	2011
	($ in millions)		
Standardized measure, beginning of period[a]	$ 14,666	$ 15,630	$ 13,183
Sales of natural gas and oil produced, net of production costs[b]	(5,535)	(3,867)	(3,993)
Net changes in prices and production costs	2,021	(2,720)	512
Extensions and discoveries, net of production and development costs	6,008	11,115	9,139
Changes in future development costs	1,287	3,687	667
Development costs incurred during the period that reduced future development costs	1,582	1,046	680
Revisions of previous quantity estimates	(805)	(8,699)	(708)
Purchase of reserves-in-place	26	285	50
Sales of reserves-in-place	(1,976)	(3,246)	(2,083)
Accretion of discount	1,777	1,988	1,515
Net change in income taxes	(1,180)	1,142	(2,286)
Changes in production rates and other	(481)	(1,695)	(1,046)
Standardized measure, end of period[a][c][d]	$ 17,390	$ 14,666	$ 15,630

(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.

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. As of 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, 2013.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the period ended December 31, 2013 which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

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, 2014 (the "2014 Proxy Statement").

ITEM 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the 2014 Proxy Statement.

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 2014 Proxy Statement.

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 2014 Proxy Statement.

ITEM 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the 2014 Proxy Statement.

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 or furnished herewith pursuant to the requirements of Item 601 of Regulation S-K:

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1.1	Chesapeake's Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	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		
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		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
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 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		
4.5*	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		
4.6*	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		
4.7*	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 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
4.8.1*	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		
4.8.2	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		
4.9.1*	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		
4.9.2	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		
4.9.3	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		
4.9.4	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		
4.9.5	Fourteenth Supplemental Indenture dated March 18, 2013 to Indenture dated as of August 2, 2010.	S-3	333-168509	4.17	3/18/2013		
4.9.6	Fifteenth Supplemental Indenture dated April 1, 2013 to Indenture dated as of August 2, 2010 with respect to 3.25% Senior Notes due 2016.	8-A	001-13726	4.2	4/8/2013		
4.9.7	Sixteenth Supplemental Indenture dated April 1, 2013 to Indenture dated as of August 2, 2010 with respect to 5.375% Senior Notes due 2021.	8-A	001-13726	4.3	4/8/2013		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.9.8	Seventeenth Supplemental Indenture dated April 1, 2013 to Indenture dated as of August 2, 2010 with respect to 5.75% Senior Notes due 2023.	8-A	001-13726	4.4	4/8/2013		
4.10.1	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		
4.10.2	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		
4.10.3	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		
4.10.4	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, and the several lenders parties thereto.	8-K	001-13726	4.1	10/1/2012		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.10.5	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, and the several lenders parties thereto.	10-K	001-13726	4.11.5	3/1/2013		
4.10.6	Fifth Amendment to Eighth Amended and Restated Credit Agreement, dated as of November 6, 2013, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P., as Borrowers, Union Bank, N.A., as Administrative Agent, and the several lenders parties thereto.					X	
4.11*	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 2013 Restricted Stock Award Agreement for Chesapeake's 2003 Stock Incentive Plan.	10-K	001-13726	10.1.3	3/1/2013		
10.2†	Chesapeake's 2002 Non-Employee Director Stock Option Plan.	10-Q	001-13726	10.1.12	8/11/2008		
10.3†	Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, as amended.	10-Q	001-13726	10.7	8/6/2013		
10.4.1†	Chesapeake's Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1	6/20/2013		
10.4.2†	Form of 2013 Restricted Stock Award Agreement for Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.3	2/4/2013		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.4.3†	Form of Nonqualified Stock Option Agreement for Amended and Restated Long Term Incentive Plan	8-K	001-13726	10.1	2/4/2013		
10.4.4†	Form of Retention Nonqualified Stock Option Agreement for Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.2	2/4/2013		
10.4.5†	Form of 2013 Non-Employee Director Restricted Stock Award Agreement for Amended and Restated Long Term Incentive Plan.	10-K	001-13726	10.13.7	3/1/2013		
10.4.6†	Form of 2013 Performance Share Unit Award Agreement for Amended and Restated Long Term Incentive Plan.	10-K	001-13726	10.13.9	3/1/2013		
10.4.7†	Form of 2014 Performance Share Unit Award Agreement for Amended and Restated Long Term Incentive Plan.					X	
10.4.8†	Form of Restricted Stock Unit Award Agreement for Amended and Restated Long Term Incentive Plan.	10-Q	001-13726	10.8	8/6/2013		
10.4.9†	Form of Non-Employee Director Restricted Stock Unit Award Agreement for Amended and Restated Long Term Incentive Plan	10-Q	001-13726	10.9	8/6/2013		
10.4.10†	Form of Pension and Equity Makeup Restricted Stock Award Agreement for Amended and Restated Long Term Incentive Plan for Robert D. Lawler.	10-Q	001-13726	10.10	8/6/2013		
10.4.11†	Restricted Stock Award Agreement for Amended and Restated Long Term Incentive Plan between Chesapeake and Aubrey K. McClendon.	10-Q	001-13726	10.5.1	5/10/2013		
10.4.12†	Nonqualified Stock Option Agreement for Amended and Restated Long Term Incentive Plan between Chesapeake and Aubrey K. McClendon.	10-Q	001-13726	10.5.2	5/10/2013		
10.4.13†	Performance Share Unit Award Agreement for Amended and Restated Long Term Incentive Plan between Chesapeake and Aubrey K. McClendon.	10-Q	001-13726	10.5.3	5/10/2013		
10.5†	Restated Founder Well Participation Program.	8-K	001-13726	1.2	5/2/2012		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.6†	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan.	10-K	001-13726	10.1.13	3/1/2011		
10.7†	Chesapeake Energy Corporation Deferred Compensation Plan for Non-Employee Directors.	10-K	001-13726	10.16	3/13/2013		
10.8†	Employment Agreement dated as of May 20, 2013 between Robert D. Lawler and Chesapeake Energy Corporation.	8-K	001-13726	10.1	5/23/2013		
10.9†	Employment Agreement dated as of January 1, 2013 between Domenic J. Dell'Osso, Jr. and Chesapeake Energy Corporation.	10-K	001-13726	10.19	3/1/2013		
10.10†	Employment Agreement dated as of January 1, 2013 between Douglas J. Jacobson and Chesapeake Energy Corporation.	10-K	001-13726	10.20	3/1/2013		
10.11†	Employment Agreement dated as of August 14, 2013 between M. Christopher Doyle and Chesapeake Energy Corporation.	10-Q/A	001-13726	10.1	11/7/2013		
10.12†	Employment Agreement dates as of August 4, 2013 between Mikell Jason Pigott and Chesapeake Energy Corporation.	10-Q/A	001-13726	10.2	11/7/2013		
10.13†	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		
10.14†	Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries.	8-K	001-13726	10.3	6/27/2012		
10.15	Founder Separation and Services Agreement, effective as of January 29, 2013, by and between Aubrey K. McClendon and Chesapeake Energy Corporation.	8-K	001-13726	10.1	4/19/2013		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	SEC File Number	Exhibit	Filing Date		
10.16	Founder Joint Operating Services Agreement, effective as of January 29, 2013, by and among Chesapeake Energy Corporation, Aubrey K. McClendon, Arcadia Resources, L.P., Larchmont Resources, L.L.C., Jamestown Resources, L.L.C., and Pelican Energy, L.L.C.	8-K	001-13726	10.2	4/19/2013		
10.17	Map Sale Rescission Agreement, effective as of April 1, 2013, by and between Aubrey K. McClendon and Chesapeake Energy Corporation.	8-K	001-13726	10.3	4/19/2013		
10.18†	Chesapeake Energy Corporation 2013 Annual Incentive Plan	DEF 14A	001-13726	Exhibit G	5/3/2013		
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 PetroTechnical Services, Division of Schlumberger Technology Corporation.					X	
23.3	Consent of Ryder Scott Company, L.P.					X	
31.1	Robert D. Lawler, 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	Robert D. Lawler, Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
32.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
99.1	Report of PetroTechnical Services, Division of Schlumberger Technology Corporation.					X	
99.2	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	

* The Company agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities 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: February 26, 2014

By: /s/ ROBERT D. LAWLER
Robert D. Lawler
President and Chief Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Robert D. Lawler 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/ ROBERT D. LAWLER **Robert D. Lawler**	President and Chief Executive Officer (Principal Executive Officer)	February 26, 2014
/s/ DOMENIC J. DELL'OSSO, JR. **Domenic J. Dell'Osso, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2014
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President - Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 26, 2014
/s/ ARCHIE W. DUNHAM **Archie W. Dunham**	Chairman of the Board	February 26, 2014
/s/ BOB G. ALEXANDER **Bob G. Alexander**	Director	February 26, 2014
/s/ VINCENT J. INTRIERI **Vincent J. Intrieri**	Director	February 26, 2014
/s/ R. BRAD MARTIN **R. Brad Martin**	Director	February 26, 2014
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	February 26, 2014
/s/ FREDRIC M. POSES **Frederic M. Poses**	Director	February 26, 2014
/s/ LOUIS A. RASPINO **Louis A. Raspino**	Director	February 26, 2014
/s/ THOMAS L. RYAN **Thomas L. Ryan**	Director	February 26, 2014

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, 2014, there were approximately 345,000 beneficial owners of our common stock.

COMMON STOCK DIVIDENDS
During 2013, the company declared a cash dividend of $0.0875 per share on April 8, June 17, September 23 and December 16 for a total dividend declared of $0.35 per share.

INDEPENDENT PUBLIC ACCOUNTANTS
PricewaterhouseCoopers LLP
211 North Robinson Avenue, Suite 1400
Oklahoma City, OK 73102
(405) 290-7200

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 and 2014
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" related to our business strategy and objectives for future operations. Although we believe there is a reasonable basis for these forward-looking statements, 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 2013 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, except as required by law. 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

2014	HIGH	LOW	LAST
First Quarter	$ 27.54	$ 23.92	$ 25.62

2013	HIGH	LOW	LAST
Fourth Quarter	$ 29.06	$ 25.06	$ 27.14
Third Quarter	27.46	20.30	25.88
Second Quarter	22.86	18.21	20.38
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

CHK LISTED NYSE

CHESAPEAKE

6100 North Western Avenue
Oklahoma City, OK 73118
chk.com