CHESAPEAKE ENERGY CORP
Form 10-K
February 27, 2014

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 (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (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/

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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 Officer
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

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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.

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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.

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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

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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.

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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	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 Production Expenses	$/boe	2012 Production Expenses	$/boe	2011 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
	2013	2012	2011	Useful Life
	($ 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)

	Volume (mmbbl)	Weighted Average Price Fixed ($ per bbl)	Call	Put	Differential	Fair Value Asset (Liability) ($ 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					