2018
ANNUAL REPORT

CHESAPEAKE ENERGY

Dear Fellow Shareholders

In 2018, Chesapeake Energy delivered a strong operational and financial performance. Consistent with our strategic focus on margin enhancements, we generated our highest adjusted EBITDA per boe since 2014 (a year when oil averaged more than $90 per barrel and natural gas averaged more than $4 per thousand cubic feet). This occurred while significantly reducing net debt and future midstream commitments.

Doug Lawler and Brad Martin

Focusing on increasing oil production resulted in 10% oil production growth in 2018, adjusted for asset sales, led by a 78% increase in annual net oil volumes in the Powder River Basin. Oil comprised 21% of our total production mix in December 2018, up from 17% in December 2017. Further oil growth will come from our acquisition of WildHorse Resource Development Corporation consummated in the first quarter of 2019. Known in our portfolio as Brazos Valley, this high-quality oil asset adds opportunities for significant increased cash flow and value acceleration for Chesapeake.

2018 PERFORMANCE HIGHLIGHTS

$1.8 billion
Reduction in net debt

10%
Adjusted oil production growth

$2.4 billion
Reduction in future midstream commitments

This progress, combined with additional efficiencies through supply chain savings, reduced controllable downtime, and recovery and development improvements, was the result of outstanding execution by our team members. Our commitment to operating responsibly again led to achieving outstanding health, safety, environmental and regulatory performance.

In 2019, we will continue our focus on reducing debt, enhancing margins and reaching sustainable free cash flow. We expect the Powder River Basin and Brazos Valley assets to drive absolute oil growth of 32% (50% when adjusted for asset sales), as we direct the majority of our drilling and completion capital expenditures to our higher-margin, higher-return oil assets in the Powder River Basin, Brazos Valley and Eagle Ford Shale.

Our leadership and dedicated team members have accomplished much during the past six years — yet there is clearly more to do. With an unwavering commitment to our core values, we will execute on our focused business strategies to create long-term value.

Sincerely,

R. Brad Martin
Chairman of the Board

Robert D. Lawler
President, Chief Executive Officer and Director

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, 2018

[ ] 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
Floating Rate Senior Notes due 2019	New York Stock Exchange
6.625% Senior Notes due 2020	New York Stock Exchange
6.875% Senior Notes due 2020	New York Stock Exchange
6.125% Senior Notes due 2021	New York Stock Exchange
5.375% Senior Notes due 2021	New York Stock Exchange
4.875% Senior Notes due 2022	New York Stock Exchange
5.75% Senior Notes due 2023	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 every Interactive Data File required to be submitted 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 such files). YES [X] NO [ ]

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

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

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 29, 2018, was approximately $4.7 billion. As of February 12, 2019, there were 1,631,724,765 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2018 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
2018 ANNUAL REPORT ON FORM 10-K
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Glossary of Oil and Gas 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. One billion cubic feet of natural gas.

Bcfe. One 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. Natural gas proved reserves and production are converted to boe at 14.73 psia and 60 degrees. Boe is based on six mcf of natural gas to one bbl of oil or one bbl of NGL. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Despite holding this ratio constant at six mcf to one bbl, prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil, natural gas or natural gas liquids, 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.

Dry Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas 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 oil or natural gas in another reservoir.

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

Full Cost. The full cost method of accounting, as governed by SEC Regulation S-X 4-10(c), consists of capitalizing all costs associated with property acquisition, exploration and development activities into a full cost pool. The full cost pool is tested for impairment quarterly using the “ceiling test” described in Regulation S-X 4-10(c). 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.

GAAP. Generally Accepted Accounting Principles in the United States.

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

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). 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 oil, natural gas and NGL reserves.

Present Value of Estimated Future Net Revenues or PV-10 (non-GAAP). When used with respect to oil, natural gas and NGL reserves, present value of estimated future net revenues, 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 oil and natural gas 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 (unless such costs are subject to change pursuant to contractual provisions), 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 oil, natural gas or NGL received at the sales point and the NYMEX price.

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. As used in this report, proved reserves has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which states in part proved oil and natural gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

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. 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.

Realized and Unrealized Gains and Losses on Oil, Natural Gas and NGL Derivatives. Realized gains and losses include the following items:(i) settlements and accruals for settlements of non-designated derivatives related to current period notional production revenues, (ii) prior period settlements for option premiums and for early-terminated derivatives originally scheduled to settle against current period notional production revenues, and (iii) gains and losses related to de-designated cash flow hedges originally designated to settle against current period notional production revenues. Unrealized gains and losses include the change in fair value of open derivatives scheduled to settle against future period notional production revenues (including current period settlements for option premiums and early-terminated derivatives) 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.

Realized and Unrealized Gains and Losses on Interest Rate Derivatives. Realized gains and losses include interest rate derivative settlements related to current period interest and the effect of gains and losses on early-terminated trades. Settlements of early-terminated trades are reflected in realized gains and losses over the original life of the hedged item. Unrealized gains and losses include changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized gains and losses during the period.

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 an oil and natural gas property entitling the owner to a share of oil, natural gas 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 formations.

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

SEC. The United States Securities and Exchange Commission.

Standardized Measure. The discounted future net cash flows relating to proved reserves based on the means of 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 oil and natural gas 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). The standardized measure differs from the PV-10 measure only because the former includes the effects of estimated future income tax expenses.

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

WildHorse. WildHorse Resource Development Corporation. Immediately following the completion of our acquisition of WildHorse (the “First Merger”), WildHorse merged with and into Brazos Valley Longhorn, L.L.C., a newly formed Delaware limited liability company and wholly owned subsidiary of Chesapeake, which, together with the First Merger, we refer to as the “WildHorse Merger.” For ease of reference, we use the term “WildHorse” to refer to WildHorse Resource Development Corporation prior to the acquisition and Brazos Valley Longhorn, L.L.C. or “Brazos Valley Longhorn” after the acquisition, as applicable.

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.

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 include our current expectations or forecasts of future events. In this context, forward-looking statements often address our expected future business and financial performance and financial condition, and often contain words such as "expect," “could,” “may,” "anticipate," "intend," "plan," “ability,” "believe," "seek," "see," "will," "would," “estimate,” “forecast,” "target," “guidance,” “outlook,” “opportunity” or “strategy.”

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time. Particular uncertainties that could cause our actual results to be materially different than those expressed in our forward-looking statements include:

- the volatility of oil, natural gas and NGL prices;
- uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- our ability to replace reserves and sustain production;
- drilling and operating risks and resulting liabilities;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- the limitations our level of indebtedness may have on our financial flexibility;
- our inability to access the capital markets on favorable terms;
- the availability of cash flows from operations and other funds to finance reserve replacement costs or satisfy our debt obligations;
- adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims;
- effects of environmental protection laws and regulation on our business;
- terrorist activities and/or cyber-attacks adversely impacting our operations;
- effects of acquisitions and dispositions, including our acquisition of WildHorse and our ability to realize related synergies;
- effects of purchase price adjustments and indemnity obligations; and
- other factors that are described under *Risk Factors* in Item 1A of this Form 10-K.

We caution you not to place undue reliance on the forward-looking statements contained in this report, which speak only as of the filing date, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures 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.

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.

Our Business

We are an independent exploration and production company engaged in the acquisition, exploration and development of properties to produce oil, natural gas and NGL from underground reservoirs. We own a large and geographically diverse portfolio of onshore U.S. unconventional liquids and natural gas assets, including interests in approximately 13,200 oil and natural gas wells. We have leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas, the stacked pay in the Powder River Basin in Wyoming and the Anadarko Basin in northwestern Oklahoma. Our natural gas resource plays are the Marcellus Shale in the northern Appalachian Basin in Pennsylvania and the Haynesville/Bossier Shales in northwestern Louisiana.

In October 2018, we sold our interests in the Utica Shale operating area located in Ohio for approximately $1.9 billion to Encino Acquisition Partners (“Encino”), a private oil and gas company headquartered in Houston, Texas. We used the net proceeds to reduce debt.

In February 2019, we acquired WildHorse Resource Development Corporation, an oil and gas company with operations in the Eagle Ford Shale and Austin Chalk formations in southeast Texas, for approximately 717.3 million shares of our common stock and $381 million in cash, and the assumption of WildHorse’s debt of $1.4 billion as of the acquisition date of February 1, 2019. The acquisition of WildHorse expands our oil growth platform and accelerates our progress toward our strategic and financial goals of enhancing our margins, achieving sustainable free cash flow generation, and reducing our net debt to EBITDA ratio. In conjunction with the acquisition under terms of the merger agreement, David W. Hayes, partner for NGP Energy Capital Management, L.L.C. (“NGP”), has joined our board and another designee of NGP is expected to be appointed to fill the next vacancy on our board.

Because the acquisition of WildHorse occurred after December 31, 2018, Chesapeake’s consolidated financial statements and the notes thereto do not include or take into account the closing of the acquisition and its effects.

Information About Us

We make available, free of charge on our website at *chk.com,* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any 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. Documents and information on our website are not incorporated by reference herein.

The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers, including Chesapeake, that file electronically with the SEC.

Business Strategy

Our strategy is to create shareholder value through the development of our significant resource plays. Our substantial inventory of hydrocarbon resources, including our undeveloped acreage position in each of our key basins, provides a strong foundation to create future value. Concentrated blocks of undeveloped acreage give us the opportunity to apply what we believe are best in class well spacing analysis, completion techniques and lateral lengths to maximize capital efficiency. We have greatly improved our capital and operating efficiency metrics over the last several years and today have what we believe is a leading cost structure in each of our major resource plays. We believe our cost structure provides a significant competitive advantage in the current commodity price environment and it is our strategy to continue to seek capital and operating efficiencies to grow this advantage.

We continue to focus on reducing debt, increasing cash provided by operating activities, improving margins through financial discipline and operating efficiencies and improving environmental and safety performance. To accomplish these goals, we intend to allocate our capital expenditures to projects we believe offer the highest return regardless of the commodity price environment, to deploy leading drilling and completion technology throughout our portfolio, and to take advantage of acquisition and divestiture opportunities to strengthen our cost structure and our portfolio. Increasing our margins means not only increasing our absolute level of cash flow from operations, but also increasing our cash flow from operations generated per barrel of oil equivalent production. We continue to seek opportunities to reduce cash costs (production, gathering, processing and transportation, general and administrative and interest expenses) through operational efficiencies, including but not limited to improving our production volumes from existing wells.

We believe that our dedication to financial discipline, the flexibility and efficiency of our capital program and cost structure and our continued focus on safety and environmental stewardship will provide opportunities to create value for us and our shareholders.

Operating Areas

We focus our exploration, development, acquisition and production efforts in the six geographic operating areas described below.

Marcellus - Northern Appalachian Basin in Pennsylvania.

Haynesville - Northwestern Louisiana (Gulf Coast).

Eagle Ford - South Texas.

Brazos Valley - Southeast Texas assets acquired in our WildHorse acquisition on February 1, 2019.

Powder River Basin - Stacked pay in Wyoming.

Mid-Continent - Anadarko Basin in northwestern Oklahoma.

Well Data

As of December 31, 2018, we held an interest in approximately 13,200 gross (5,600 net) productive wells, including 10,200 properties in which we held a working interest and 3,000 properties in which we held an overriding or royalty interest. Of the 10,200 properties in which we had a working interest, we operated 7,200 wells, 6,800 gross (3,800 net), of which were classified as productive natural gas wells and 3,400 gross (1,800 net) were classified as productive oil wells. During 2018, we drilled or participated in 351 gross (238 net) wells as operator and participated in another 26 gross (1 net) wells completed by other operators. We operate approximately 97% 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:

	2018				2017				2016			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	363	99	227	99	462	99	292	99	431	99	236	99
Dry	2	1	1	1	4	1	2	1	1	1	1	1
Total	365	100	228	100	466	100	294	100	432	100	237	100
Exploratory:												
Productive	10	83	9	82	2	100	2	100	3	100	2	100
Dry	2	17	2	18	—	—	—	—	—	—	—	—
Total	12	100	11	100	2	100	2	100	3	100	2	100

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

	2018		2017		2016	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Marcellus	52	23	43	21	19	9
Haynesville	30	21	37	34	41	34
Eagle Ford	162	98	180	106	199	116
Powder River Basin	41	34	25	21	1	1
Mid-Continent	52	32	114	58	135	62
Utica	40	31	69	56	34	17
Other	—	—	—	—	6	—
Total	377	239	468	296	435	239

As of December 31, 2018, we had 149 gross (82 net) wells in the process of being drilled or completed.

Production, Sales Prices, Production and Gathering, Processing and Transportation Expenses

The following table sets forth information regarding our net production volumes, average sales price received for our production, average sales price of our production combined with our realized gains or losses on derivatives and production and gathering, processing and transportation expenses per boe for the periods indicated:

	Years Ended December 31,		
	2018	2017	2016
Net Production:			
Oil (mmbbl)	33	33	33
Natural gas (bcf)	832	878	1,049
NGL (mmbbl)	19	21	24
Oil equivalent (mmboe)	190	200	233
Average Sales Price of Production:			
Oil ($ per bbl)	$ 67.25	$ 51.03	$ 40.65
Natural gas ($ per mcf)	$ 2.99	$ 2.76	$ 2.05
NGL ($ per bbl)	$ 26.50	$ 23.18	$ 14.76
Oil equivalent ($ per boe)	$ 27.27	$ 22.88	$ 16.63
Average Sales Price (including realized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 57.42	$ 53.19	$ 43.58
Natural gas ($ per mcf)	$ 3.00	$ 2.75	$ 2.20
NGL ($ per bbl)	$ 25.84	$ 22.98	$ 14.43
Oil equivalent ($ per boe)	$ 25.56	$ 23.17	$ 17.66
Expenses ($ per boe):			
Oil, natural gas and NGL production	$ 2.84	$ 2.81	$ 3.05
Oil, natural gas and NGL gathering, processing and transportation	$ 7.35	$ 7.36	$ 7.98

Oil, Natural Gas and NGL Reserves

The tables below set forth information as of December 31, 2018, with respect to our estimated proved reserves, the associated estimated future net revenue, the present value of estimated future net revenue ("PV-10") and the standardized measure of discounted future net cash flows ("standardized measure"). None of the estimated future net revenue, PV-10 nor the standardized measure are intended to represent the current market value of the estimated oil, natural gas and NGL reserves we own. All of our estimated reserves are located within the United States.

	December 31, 2018			
	Oil (mmbbl)	Natural Gas (bcf)	NGL (mmbbl)	Total (mmboe)
Proved developed	127.6	3,314	67.9	748
Proved undeveloped	87.9	3,463	35.4	700
Total proved[a]	215.5	6,777	103.3	1,448

	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue[b]	$ 10,214	$ 7,120	$ 17,334
Present value of estimated future net revenue (PV-10)[b]	$ 6,177	$ 3,350	$ 9,527
Standardized measure[b]			$ 9,495

(a) Marcellus, Haynesville and Eagle Ford accounted for approximately 40%, 27%, and 22%, respectively, of our estimated proved reserves by volume as of December 31, 2018.

(b) Estimated future net revenue represents the estimated future 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, 2018, and assuming commodity prices as set forth below. For the purpose of determining prices used in our reserve reports, we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2018. The prices used in our PV-10 measure were $65.56 of oil and $3.10 of natural gas, before basis differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity derivative instruments in place as of December 31, 2018. The amounts shown do not give effect to non-property-related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue typically differs from the standardized measure because the former does not include the effects of estimated future income tax expense of $32 million as of December 31, 2018.

Management uses PV-10, which is calculated without deducting estimated future income tax expenses, 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 estimated future net revenue and the present value thereof are based on prices, costs and discount factors which may be 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. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP.

A reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented above. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

As of December 31, 2018, our proved reserve estimates included 700 mmboe of reserves classified as proved undeveloped, compared to 796 mmboe as of December 31, 2017. Presented below is a summary of changes in our proved undeveloped reserves (PUDs) for 2018:

	Total
	(mmboe)
Proved undeveloped reserves, beginning of period	796
Extensions and discoveries	236
Revisions of previous estimates	(27)
Developed	(115)
Sale of reserves-in-place	(190)
Proved undeveloped reserves, end of period	700

As of December 31, 2018, all PUDs were planned to be developed within five years. In 2018, we invested approximately $807 million to convert 115 mmboe of PUDs to proved developed reserves. In 2019, we estimate that we will invest approximately $1.2 billion for PUD conversion. We added 236 mmboe of proved undeveloped reserves through extensions and discoveries primarily as a result of longer planned lateral lengths and additional allocated capital in our five-year development plan. We sold 190 mmboe of proved undeveloped reserves primarily in the divestiture of Utica Shale assets. We recorded a downward revision of 27 mmboe from previous estimates due to ongoing portfolio evaluation including longer lateral and spacing adjustments.

The future net revenue attributable to our estimated PUDs was $7.1 billion and the present value was $3.3 billion as of December 31, 2018. These values were calculated assuming that we will expend approximately $3.6 billion to develop these reserves ($1.2 billion in 2019, $984 million in 2020, $901 million in 2021, $337 million in 2022 and $166 million in 2023). 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. Our developmental drilling schedules are subject to revision and reprioritization throughout the year resulting from unknowable factors such as unexpected developmental drilling results, title issues and infrastructure availability or constraints.

Of our 748 mmboe of proved developed reserves as of December 31, 2018, approximately 20 mmboe, or 3%, were non-producing.

Our ownership interest used for calculating proved reserves and the associated estimated future net revenue assumes maximum participation by other parties to our farm-out and participation agreements.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves as of December 31, 2018, 2017 and 2016, along with the changes in quantities and standardized measure of the reserves for each of the three years then ended, are shown in *Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities* included in Item 8 of Part II 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 represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas 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 these estimates, and these revisions may be material. Accordingly, reserve estimates often differ from the actual quantities of oil, natural gas 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. See *Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities* included in Item 8 of Part II of this report for further discussion of our reserve quantities.

Reserves Estimation

Our Corporate Reserves Department prepared approximately 20% by volume, and approximately 18% by value, of our estimated proved reserves disclosed in this report. Those estimates were based upon the best available production, engineering and geologic data.

Our Director – Corporate Reserves, is the technical person primarily responsible for overseeing the preparation of our reserve estimates and for coordinating any reserves work conducted by a third-party engineering firm. Her qualifications include the following:

- Over 15 years of practical experience in the oil and gas industry, with 12 years in reservoir engineering;
- Bachelor of Science degree in Geology and Environmental Sciences;
- Master's Degree in Petroleum and Natural Gas Engineering;
- Executive MBA; and
- Member in good standing of the Society of Petroleum Engineers.

We ensure that the key members of our Corporate Reserves Department have appropriate technical qualifications to oversee the preparation of reserves estimates. Each of our Corporate Reserves Engineers has significant engineering experience in reserve estimation. Our engineering technicians have a minimum of a four-year degree in mathematics, economics, finance or other technical/business/science field. 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 estimate and report proved reserves. Reserve estimates are made by experienced reservoir engineers or under their direct supervision. All material changes are reviewed and approved by Corporate Reserves Engineers.
- The Corporate Reserves Department reviews our proved reserves at the close of each quarter.
- Each quarter, Reservoir Managers, the Director – Corporate Reserves, the Vice Presidents of our business units, the Vice President of Corporate and Strategic Planning and the Executive Vice President – Exploration and Production review all significant reserves changes and all new proved undeveloped reserves additions.
- The Corporate Reserves Department reports independently of our operations.
- The five-year PUD development plan is reviewed and approved annually by the Director – Corporate Reserves and the Vice President of Corporate and Strategic Planning.

We engaged Software Integrated Solutions, Division of Schlumberger Technology Corporation, a third-party engineering firm, to prepare approximately 80% by volume, and approximately 82% by value, of our estimated proved reserves as of December 31, 2018. A copy of the report issued by the engineering firm is filed with this report as Exhibit 99.1. The qualifications of the technical person at the firm primarily responsible for overseeing the preparation of our reserve estimates are set forth below.

- over 30 years of practical experience in the estimation and evaluation of reserves;
- registered professional geologist license in the Commonwealth of Pennsylvania;
- member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and
- Bachelor of Science degree in Geological Sciences.

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

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

	Years Ended December 31, 2018	2017	2016
	($ in millions)		
Acquisition of Properties:			
Proved properties	$ 80	$ 23	$ 403
Unproved properties	216	271	403
Exploratory costs	132	21	52
Development costs	2,009	2,146	1,312
Costs incurred[(a)]	$ 2,437	$ 2,461	$ 2,170

(a) Includes capitalized interest and asset retirement obligations as follows:

Capitalized interest	$ 162	$ 194	$ 242
Asset retirement obligations[(b)]	$ 8	$ (34)	$ (57)

(b) Activity in 2017 and 2016 primarily reflects revisions as the result of decreased plugging and abandonment costs in certain of our operating areas.

A summary of our exploration and development, acquisition and divestiture activities in 2018 by operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Acquisition of Unproved Properties	Acquisition of Proved Properties	Sales of Unproved Properties	Sales of Proved Properties[(a)]	Total[(b)]
			($ in millions)					
Marcellus	52	23	$ 170	$ 5	$ 1	$ (2)	$ —	$ 174
Haynesville	30	21	346	6	—	(5)	(8)	339
Eagle Ford	162	98	696	14	—	(2)	—	708
Powder River Basin	41	34	395	73	—	(28)	—	440
Mid-Continent	52	32	201	19	1	(123)	(262)	(164)
Utica	40	31	301	90	77	(325)	(2,039)	(1,896)
Other	—	—	32	9	1	—	(6)	36
Total	377	239	$ 2,141	$ 216	$ 80	$ (485)	$ (2,315)	$ (363)

(a) Includes asset retirement disposal of $28 million related to divestitures.

(b) Includes capitalized internal costs of $121 million and capitalized interest of $162 million.

Acreage

The following table sets forth our gross and net developed and undeveloped oil and natural gas leasehold and fee mineral acreage as of December 31, 2018. 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)							
Marcellus	541	347	265	177	16	16	822	540
Haynesville	302	270	99	67	—	—	401	337
Eagle Ford	308	183	77	52	—	—	385	235
Powder River Basin	73	58	244	189	1	1	318	248
Mid-Continent	926	602	200	132	38	34	1,164	768
Other[(a)]	184	146	1,066	983	435	431	1,685	1,560
Total	2,334	1,606	1,951	1,600	490	482	4,775	3,688

(a) Includes 1.3 million net acres retained in the 2016 fourth quarter divestiture of our Devonian Shale assets, in which we retained all rights below the base of the Kope formation.

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 the expiration periods of gross and net undeveloped leasehold acres as of December 31, 2018:

	Acres Expiring	
	Gross Acres	Net Acres
	(in thousands)	
Years Ending December 31:		
2019	108	87
2020	49	44
2021	37	27
After 2021	53	51
Held-by-production[(a)]	1,704	1,391
Total	1,951	1,600

(a) Held-by-production acres will remain in force as production continues on the subject leases.

Marketing

The principal function of our marketing operations is to provide oil, natural gas and NGL marketing services, including commodity price structuring, securing and negotiating of gathering, hauling, processing and transportation services, contract administration and nomination services for us and other interest owners in Chesapeake-operated wells. The marketing operations also provide other services for our exploration and production activities, including services to enhance the value of oil and natural gas production by aggregating volumes 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. In addition, we periodically enter into a variety of oil, natural gas and NGL purchase and sale contracts with third parties for various commercial purposes, including credit risk mitigation and satisfaction of our pipeline delivery commitments.

Generally, our oil production is 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. Under the terms of our percentage-of-proceeds contracts, we receive a percentage of the resale price received from the ultimate purchaser. Under our percentage-of-index contracts, the price we receive is tied to published indices.

We have entered into long-term gathering, processing, and transportation contracts with various parties that require us to deliver fixed, determinable quantities of production over specified periods of time. Certain of our contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under these commitments. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of commitments.

Major Customers

Sales to Valero Energy Corporation constituted approximately 10% of our total revenues (before the effects of hedging) for the year ended December 31, 2018. No other purchasers accounted for more than 10% of our total revenues for 2018. Sales to Royal Dutch Shell PLC constituted approximately 10% of our total revenues (before the effects of hedging) for the year ended December 31, 2017. Sales to BP PLC constituted approximately 10% of our total revenues (before the effects of hedging) for the year ended December 31, 2016.

Competition

We compete with both major integrated and other independent oil and natural gas 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 us. Competitive conditions may be affected by future legislation and regulations as the United States develops new energy and climate-related policies. In addition, some of our competitors may have a competitive advantage when responding to factors that affect demand for oil and natural gas 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 also face indirect competition from alternative energy sources, including wind, solar and electric power. We believe that our technological expertise, combined with our exploration, land, drilling and production capabilities and the experience of our management team, enables us to compete effectively.

Public Policy and Government Regulation

All of our operations are conducted onshore in the United States. Our industry is subject to a wide range of regulations, laws, rules, taxes, fees and other policy implementation actions that have been pervasive and are under constant review for amendment or expansion. Numerous government agencies have issued extensive regulations which are binding on our industry, some of which carry substantial penalties for failure to comply. These laws and regulations increase the cost of doing business and consequently affect profitability. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. We actively monitor regulatory developments applicable to our industry in order to anticipate, design and implement required compliance activities and systems. The following are significant areas of government control and regulation affecting our operations.

Regulation – Environment, Health and Safety

Exploration and Production, Environmental, Health and Safety, and Occupational Laws and Regulations

Our operations are subject to federal, tribal, state, and local laws and regulations. These laws and regulations relate to matters that include, but are not limited to, the following:

- reporting of workplace injuries and illnesses;
- industrial hygiene monitoring;
- worker protection and workplace safety;
- approval or permits to drill and to conduct operations;
- provision of financial assurances (such as bonds) covering drilling and well operations;
- calculation and disbursement of royalty payments and production taxes;
- seismic operations and data;
- location, drilling, cementing and casing of wells;
- well design and construction of pad and equipment;
- construction and operations activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species, their habitats, or sites of cultural significance;
- method of completing wells;
- hydraulic fracturing;
- water withdrawal;
- well production and operations, including processing and gathering systems;
- emergency response, contingency plans and spill prevention plans;
- air emissions and fluid discharges;
- climate change;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage, maintenance, monitoring and the restoration of properties associated with well pads, pipelines, impoundments and access roads;
- plugging and abandoning of wells; and
- transportation of production.

Failure to comply with these laws and regulations can lead to the imposition of remedial liabilities, fines, or criminal penalties or to injunctions limiting our operations in affected areas. Moreover, multiple environmental laws provide for citizen suits which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. We consider the costs of environmental protection and of safety and health compliance to be necessary, manageable parts of our business. We have been able to plan for and comply with environmental, safety and health laws and regulations without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to compliance with the protection of the environment, safety and health have increased over the years and may continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters. See the *Risk Factors* described in Item 1A of this report for further discussion of governmental regulation and ongoing regulatory changes, including with respect to environmental matters,

Our operations are also subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in a unit, the rate of production allowable from oil and gas wells, and the unitization or pooling of oil and gas properties. In the United States, some states allow the forced pooling or integration of tracts to facilitate exploration. Other states rely on voluntary pooling of lands and leases which may make it more difficult to develop oil and gas properties. In addition, federal and state conservation laws generally limit the venting or flaring of natural gas, and state conservation laws impose certain requirements regarding the ratable purchase of production. These regulations limit the amounts of oil and gas we can produce from our wells and the number of wells or the locations at which we can drill.

Regulatory proposals in some states and local communities have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Federal and state agencies have continued to assess the potential impacts of hydraulic fracturing, which could spur further action toward federal, state and/or local legislation and regulation. Further restrictions of hydraulic fracturing could reduce the amount of oil, natural gas and NGL that we are ultimately able to produce in commercial quantities from our properties.

Certain of our U.S. natural gas and oil leases are granted or approved by the federal government and administered by the Bureau of Land Management (BLM) or Bureau of Indian Affairs (BIA) of the Department of the Interior. Such leases require compliance with detailed federal regulations and orders that regulate, among other matters, drilling and operations on lands covered by these leases and calculation and disbursement of royalty payments to the federal government, tribes or tribal members. The federal government has been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding, venting and flaring, oil and gas measurement and royalty payment obligations for production from federal lands. In addition, permitting activities on federal lands are subject to frequent delays.

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 applicable regulations or permit requirements could result in revocation of our permits, inability to obtain new permits and the imposition of fines and penalties.

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 oil and natural gas 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 oil and natural gas industry. Nevertheless, we are involved in title disputes from time to time that may result in litigation.

Operating Hazards and Insurance

The oil and natural gas 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, we 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.

We maintain a control of well insurance policy with a $50 million single well limit and a $100 million multiple wells limit 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. We also carry a $250 million comprehensive general liability umbrella insurance policy. In addition, we maintain a $75 million pollution liability insurance policy providing coverage for gradual pollution related risks and in excess of the general liability policy for sudden and accidental pollution risks. 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, and policy limits scale to our working interest percentage in certain situations. 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. Our insurance coverage may not be sufficient to cover every claim made against us or may not be commercially available for purchase in the future.

Facilities

We own an office complex in Oklahoma City and we own or lease 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, 52, has served as President and Chief Executive Officer since June 2013. Prior to 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., 42, has served as Executive Vice President and Chief Financial Officer since November 2010. Mr. Dell'Osso served as our Vice President – Finance and Chief Financial Officer of our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., from August 2008 to November 2010.

Frank J. Patterson, *Executive Vice President – Exploration and Production*

Frank J. Patterson, 60, has served as Executive Vice President - Exploration and Production since August 2016. Previously, he served as Executive Vice President – Exploration and Northern Division since April 2016 and as Executive Vice President – Exploration, Technology & Land since May 2015. Before joining Chesapeake, Mr. Patterson served in various roles at Anadarko from 2006 to 2015, most recently as Senior Vice President – International Exploration. Prior to that he was Vice President – Deepwater Exploration at Kerr-McGee and Manager – Geology at Sun E&P/Oryx Energy.

M. Jason Pigott, *Executive Vice President – Operations and Technical Services*

M. Jason Pigott, 45, has served as Executive Vice President – Operations and Technical Services since August 2016. Previously, he served as Executive Vice President – Operations, Southern Division since January 2015 and 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.

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

James R. Webb, 51, 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.

William M. Buergler – Senior Vice President and Chief Accounting Officer

William Buergler, 46, has served as Senior Vice President and Chief Accounting Officer since August 2017. Previously, he served as Vice President - Tax since July 2014. Before joining Chesapeake, he worked for Ernst & Young LLP, where he served as a Partner since 2009.

Employees

We had approximately 2,350 employees as of December 31, 2018.

ITEM 1A. *Risk Factors*

There are numerous factors that affect our business and operating results, many of which are beyond our control. The following is a description of significant factors that might cause our future results to differ materially from those currently expected. The risks described below are not the only risks facing our company. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also affect our business operations. If any of these risks actually occur, our business, financial position, operating results, cash flows, reserves and/or our ability to pay our debts and other liabilities could suffer, the trading price and liquidity of our securities could decline and you may lose all or part of your investment in our securities.

Oil, natural gas 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, liquidity and ability to grow depend primarily upon the prices we receive for the oil, natural gas and NGL we sell. We incur substantial expenditures to replace reserves, sustain production and fund our business plans. Low oil, natural gas and NGL prices can negatively affect the amount of cash available for capital expenditures, debt service and debt repayment 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, cash flows and reserves. In addition, periods of low oil and natural gas prices may result in ceiling test write-downs of our oil and natural gas properties.

Historically, the markets for oil, natural gas and NGL have been volatile, and they are likely to continue to be volatile. For example, during the period from January 1, 2014 to December 31, 2018, NYMEX WTI oil prices ranged from a high of $107.26 per bbl to a low of $26.21 per bbl and NYMEX Henry Hub natural gas prices ranged from a high of $6.15 per MMBtu to a low of $1.64 per MMBtu. As of February 22, 2019, the NYMEX WTI oil price was $57.08 per bbl and the NYMEX Henry Hub natural gas price was $2.72 per MMBtu.

Wide fluctuations in oil, natural gas and NGL prices may result from factors that are beyond our control, including:

- domestic and worldwide supplies of oil, natural gas and NGL, including U.S. inventories of oil and natural gas reserves;
- weather conditions;
- changes in the level of consumer and industrial demand;
- the price and availability of alternative fuels;
- technological advances affecting energy consumption;
- 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;
- U.S. exports of oil, natural gas, liquefied natural gas and NGL;
- 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 natural gas producing regions;
- acts of terrorism; and
- domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. As of February 22, 2019, including January and February derivative contracts that have settled, approximately 63% of our forecasted oil, natural gas and NGL production revenue was hedged, including 56% and 81% of our forecasted 2019 oil and natural gas production (including WildHorse production from February 1, 2019) at average prices of $57.12 per barrel and $2.85 per mcf, respectively. Even with oil, natural gas and NGL derivatives currently in place to mitigate price risks associated with a portion of our 2019 cash flows, we have substantial exposure to oil, natural gas and NGL prices in 2020 and beyond. In addition, a prolonged extension of lower prices could reduce the quantities of reserves that we may economically produce.

We have a significant amount of indebtedness. Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects, and we may have difficulty paying our debts as they become due.

As of December 31, 2018, we had approximately $8.2 billion in principal amount of debt outstanding (including $381 million of current maturities and $419 million drawn under our senior secured revolving credit facility). As of December 31, 2018, we had approximately $107 million of letters of credit issued and borrowing capacity of approximately $2.5 billion under our $3.0 billion senior secured revolving credit facility (the “Chesapeake revolving credit facility”). In addition, on February 1, 2019, we acquired $1.4 billion principal amount of debt upon the closing of the WildHorse Merger (including $675 million drawn under the WildHorse senior secured revolving credit facility (the “WildHorse revolving credit facility”)). We had approximately $47 million of letters of credit issued and borrowing capacity of approximately $578 million under the $1.3 billion WildHorse revolving credit facility. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our debt obligations, including debt maturities for the next five years and thereafter.

The level of and terms and conditions governing our debt:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt obligations and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increase our vulnerability to the cyclical nature of our business, economic downturns or other adverse developments in our business;
- could limit our ability to access capital markets, refinance our existing indebtedness, raise capital on favorable terms, or obtain additional financing for working capital, capital expenditures, acquisitions, debt service requirements, execution of our business strategy, or for other purposes;
- expose us to the risk of increased interest rates as certain of our borrowings, including borrowings under the Chesapeake revolving credit facility and the WildHorse revolving credit facility, bear interest at floating rates;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size, or those that have less restrictive terms governing their indebtedness, thereby enabling competitors to take advantage of opportunities that our indebtedness may prevent us from pursuing;
- limit management’s discretion in operating our business; and
- increase our cost of borrowing.

Any of the above listed factors could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our ability to pay our expenses and fund our working capital needs and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as commodity prices, other economic conditions and governmental regulation. We have drawn on our credit facilities for liquidity, and the borrowing bases under our $3.0 billion Chesapeake credit facility and our $1.3 billion WildHorse revolving credit facility are subject to redeterminations in the second quarter of 2019. If our borrowing bases under our revolving credit facilities decrease as a result of lower prices of oil, natural gas or NGL, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. To the extent that the value of the collateral pledged under either or both of our credit facilities declines as a result of lower oil and natural gas prices, asset dispositions or otherwise, we may be required to pledge additional collateral in order to maintain the current availability of the commitments thereunder, and we cannot assure you that we will be able to maintain a sufficiently high valuation to maintain the current commitments. In addition, we cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we are unable to service our indebtedness and other obligations, we may be required to restructure or refinance all or part of our existing debt, sell assets, reduce capital expenditures, borrow more money or raise equity, some or all of which may not be available to us on terms acceptable to us, if at all, or such alternative strategies may yield insufficient funds to make required payments on our indebtedness. In addition, our ability to comply with the financial and other restrictive covenants in our indebtedness could be affected by our future performance and events or circumstances beyond our control. Failure to comply with these covenants would result in an event of default under such indebtedness, the potential acceleration of our obligation to repay outstanding debt and the potential foreclosure on the collateral securing such debt, and could cause a cross-default under our other outstanding indebtedness. Any of the above risks could materially adversely affect our business, financial condition, cash flows and results of operations.

We have significant capital needs, and our ability to access the capital and credit markets to raise capital on favorable terms is limited by our debt level and industry conditions.

Disruptions in the capital and credit markets, in particular with respect to the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. Low commodity prices have caused and may continue to cause lenders to increase the interest rates under our credit facilities, enact tighter lending standards, refuse to refinance existing debt around maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. If we are unable to access the capital and credit markets on favorable terms, it could have a material adverse effect on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt. Additionally, challenges in the economy have led and could further lead to reductions in the demand for oil and gas, or further reductions in the prices of oil and gas, or both, which could have a negative impact on our financial position, results of operations and cash flows.

If we are unable to generate enough cash flow from operations to service our indebtedness or are unable to use future borrowings to refinance our indebtedness or fund other capital needs, we may have to undertake alternative financing plans, which may have onerous terms or may be unavailable.

Our earnings and cash flow could vary significantly from year to year due to the volatility of hydrocarbon commodity prices. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. A range of economic, competitive, business and industry factors will affect our future financial performance and, as a result, our ability to generate cash flow from operations and service our debt. Factors that may cause us to generate cash flow that is insufficient to meet our debt obligations include the events and risks related to our business, many of which are beyond our control. Any cash flow insufficiency would have a material adverse impact on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt.

If we do not generate sufficient cash flow from operations to service our outstanding indebtedness, or if future borrowings are not available to us in an amount sufficient to enable us to pay or refinance our indebtedness, we may be required to undertake various alternative financing plans, which may include:

- refinancing or restructuring all or a portion of our debt;
- seeking alternative financing or additional capital investment;
- selling strategic assets;
- reducing or delaying capital investments; or
- revising or delaying our strategic plans.

We cannot assure you that we would be able to implement any of the above alternative financing plans, if necessary, on commercially reasonable terms or at all. If we are unable to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing, our business, financial condition, results of operations, cash flows and liquidity could be materially and adversely affected. Any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could significantly harm our ability to incur additional indebtedness on acceptable terms. Further, if for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors under those agreements to declare all outstanding indebtedness thereunder to be due and payable (which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements), the lenders under our credit facilities could terminate their commitments to extend credit, and the lenders could foreclose against our assets securing their borrowings and we could be forced into bankruptcy or liquidation. In addition, the lenders under our credit facilities could compel us to apply our available cash to repay our borrowings. If the amounts outstanding under the credit facilities or any of our other significant indebtedness were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full the amounts owed to the lenders or to our other debt holders.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase.

Borrowings under our revolving credit facilities and floating rate senior notes due 2019 bear interest at variable rates and expose us to interest rate risk. As of December 31, 2018, we had $799 million of variable rate indebtedness outstanding. If interest rates increase and we are unable to hedge our interest rate risk on acceptable terms, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same.

Restrictive covenants in certain of our debt agreements could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our debt agreements impose operating and financial restrictions on us. These restrictions limit our ability and that of our restricted subsidiaries to, among other things:

- incur additional indebtedness;
- make investments or loans;
- create liens;
- consummate mergers and similar fundamental changes;
- make restricted payments;
- make investments in unrestricted subsidiaries;
- enter into transactions with affiliates; and
- use the proceeds of asset sales.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under certain of our debt agreements. The restrictions contained in the covenants could:

- limit our ability to plan for, or react to, market conditions, to meet capital needs or otherwise to restrict our activities or business plan; and
- adversely affect our ability to finance our operations, enter into acquisitions or divestitures to engage in other business activities that would be in our interest.

Also, our credit facilities require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Declines in oil, NGL and natural gas prices, or a prolonged period of low oil, NGL and natural gas prices and other events, some of which are beyond our control, could eventually result in our failing to meet one or more of the financial covenants under our credit facilities, which could require us to refinance or amend such obligations resulting in the payment of consent fees or higher interest rates, or require us to raise additional capital at an inopportune time or on terms not favorable to us.

The WildHorse revolving credit facility and the WildHorse Indenture constrain the ability of WildHorse and its subsidiaries to make distributions or otherwise provide funds to, or guarantee the obligations of, Chesapeake and its other subsidiaries. The provisions of the WildHorse revolving credit facility and the WildHorse Indenture require that all transactions between WildHorse and its subsidiaries, on the one hand, and Chesapeake and its other subsidiaries, on the other hand, be on an arm's-length basis.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our credit facilities that, if not cured or waived, could result in acceleration of all indebtedness outstanding thereunder and cross-default rights under our other debt. In addition, in the event of an event of default under one of the credit facilities, the affected lenders could foreclose on the collateral securing such credit facility and require repayment of all borrowings outstanding thereunder. If the amounts outstanding under the credit facilities or any of our other indebtedness were to be accelerated, our assets may not be sufficient to repay in full the amounts owed to the lenders or to our other debt holders.

Our credit rating could negatively impact our availability and cost of capital and could require us to post more collateral under certain commercial arrangements.

Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as gathering, transportation, processing and hedging agreements. These collateral requirements depend, in part, on our credit ratings. As of February 22, 2019, we have received requests and posted approximately $162 million of collateral related to certain of our marketing and other contracts. We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $355 million, which may be in the form of additional letters of credit, cash or other acceptable collateral. Any downgrade to our credit ratings could impact the posting of collateral consisting of cash or letters of credit, which would reduce availability under our credit facilities, and negatively impact our liquidity.

Declines in commodity prices could result in write downs of the carrying value of our oil and natural gas properties.

Under the full cost method of accounting for costs related to our oil and natural gas properties, we are required to write down the carrying value of our oil and natural gas assets if capitalized costs exceed the present value of future net revenues of our proved reserves, which is based on the average of commodity prices on the first day of the month over the trailing 12-month period. Such write-downs could be material. As of December 31, 2018, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $9.5 billion, which exceeds the carrying value of our oil and natural gas properties. See *Impairment of Oil and Natural Gas Properties* included in Item 7 of this report for further information.

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

Our exploration, development and acquisition activities 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 revolving credit facilities. Our ability to generate operating cash flow is subject to a number of risks and variables, such as the level of production from existing wells, prices of oil, natural gas and NGL, our success in developing and producing new reserves and the other risk factors discussed herein. Our forecasted 2019 capital expenditures, inclusive of Brazos Valley and capitalized interest, are $2.3 - $2.5 billion compared to our 2018 capital spending level of $2.4 billion. Management continues to review operational plans for 2019 and beyond, which could result in changes to projected capital expenditures and projected revenues from sales of oil, natural gas and NGL. If we are unable to fund our capital expenditures as planned, we could experience a curtailment of our exploration and development activity, a loss of properties and a decline in our oil, natural gas and NGL reserves.

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

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas 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. Thus, our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

The actual quantities of and future net revenues from our proved reserves may be less than our estimates.

The estimates of our proved reserves and the estimated future net revenues from our proved reserves included in this report are based upon various assumptions, including assumptions required by the SEC relating to oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil, natural gas 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, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas 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 oil and natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2018, approximately 48% 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 $3.6 billion during the next five years ending in 2023. 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 our PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove them 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 oil and natural gas 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, 2018 present value is based on a $65.56 per bbl of oil price and a $3.10 per mcf of natural gas price, before considering basis 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 oil and natural gas properties will affect both the timing of future net cash flows from our proved reserves and their present value. Any changes in demand for oil and natural gas, governmental regulations or taxation will also affect the future net cash flows from our production. In addition, the 10% discount factor that is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor. Interest rates in effect from time to time and the risks associated with our business or the oil and gas industry in general will affect the appropriateness of the 10% discount factor.

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

We have a substantial inventory of undeveloped properties. Development and exploratory drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not 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 oil and natural gas 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 and completion operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, title problems, equipment failures or accidents, shortages of midstream transportation, equipment or personnel, environmental issues, state or local bans or moratoriums on hydraulic fracturing and produced water disposal, and a decline in commodity prices, among others. The profitability of wells, particularly in certain of the areas in which we operate, will be reduced or eliminated if commodity prices decline. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for oil, natural gas and NGL, costs associated with producing oil, natural gas and NGL and our ability to add reserves at an acceptable cost. All costs of development and exploratory drilling activities are capitalized under the full cost method, even if the activities do not result in commercially productive discoveries, which may result in a future impairment of our oil and natural gas properties if commodity prices decrease.

We rely to a significant extent on seismic data and other 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 oil or natural gas is present or may be produced economically. If we incur significant expense in acquiring or developing properties that do not produce as expected or at profitable levels, it could have a material adverse effect on our results of operations and financial condition.

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

Leases on oil and natural gas 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 on our undeveloped properties 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, oil and natural gas 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. Low commodity prices may cause us to delay our drilling plans and, as a result, lose our right to develop the related properties.

Our commodity price risk management activities may limit the benefit we would receive from increases in commodity prices, may 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, we enter into oil, natural gas and NGL price derivative contracts. Our oil, natural gas and NGL derivative arrangements may limit the benefit we would receive from increases in commodity prices. The fair value of our oil, natural gas and NGL derivative instruments can fluctuate significantly between periods. Our decision to mitigate cash flow volatility through derivative arrangements, if any, is based in part on our view of current and future market conditions and our desire to stabilize cash flows necessary for the development of our proved reserves. We may choose not to enter into derivatives if the pricing environment for certain time periods is not deemed to be favorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities to monetize gain positions for the purpose of funding our capital program.

Most of our oil, natural gas and NGL derivative contracts are with counterparties under bi-lateral hedging arrangements. Under a majority of our arrangements, the collateral provided for our obligations is secured by the same hydrocarbon interests that secure the Chesapeake revolving credit facility or the WildHorse revolving credit facility, as the case may be. Under other arrangements, our obligations under the bi-lateral hedging arrangements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds. Under certain circumstances, the cash collateral value posted could fall below the coverage designated, and we would be required to post additional cash or letter of credit collateral under our hedging arrangements. Our counterparties' obligations under the arrangements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us exceed defined thresholds. Collateral requirements are dependent to a large extent on oil and natural gas prices.

Oil, natural gas and NGL derivative transactions expose us to the risk that our counterparties, which are generally financial institutions, may be unable to satisfy their obligations to us. During periods of declining commodity prices, the value of our commodity derivative asset positions increase, which increases our counterparty exposure. Although the counterparties to our hedging arrangements 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 cash flows being exposed to commodity price changes.

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

We are defending against claims by royalty owners alleging, among other things, that we used below-market prices, made improper deductions, used improper measurement techniques, entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sales of natural gas and NGL and similar theories. Numerous cases are pending. The resolution of disputes regarding past payments could cause our future obligations to royalty owners to increase and would negatively impact our future results of operations.

In addition, there are ongoing governmental regulatory investigations and inquiries into various matters such as our royalty practices. The outcome of any pending or future litigation or governmental regulatory matter is uncertain and may adversely affect our results of operations. In addition, we have incurred substantial legal expenses in the past three years, and such expenses may continue to be significant in the future. Further, attention to these matters by members of our senior management has been required, reducing the time they have available to devote to managing our business.

We may continue to incur cash and noncash charges that would negatively impact our future results of operations and liquidity.

While executing our strategic priorities to reduce financial leverage and complexity and to lower our capital expenditures in the face of lower commodity prices, we have incurred certain cash charges, including contract termination charges, restructuring and other termination costs, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity. As we continue to focus on our strategic priorities, we may incur additional cash and noncash charges in 2019 and in future years. If incurred, these charges could materially adversely impact our future results of operations and liquidity.

Oil and natural gas operations are uncertain and involve substantial costs and risks.

Our oil and natural gas operating activities are subject to numerous costs and risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. Drilling for oil, gas and NGLs can be unprofitable, not only from dry holes, but from productive wells that do not return a profit because of insufficient revenue from production or high costs. Substantial costs are required to locate, acquire and develop oil and gas properties, and we are often uncertain as to the amount and timing of those costs. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Declines in commodity prices and overruns in budgeted expenditures are common risks that can make a particular project uneconomic or less economic than forecasted. While both exploratory and developmental drilling activities involve these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. For the 3% of our daily production volumes from properties which we did not serve as operator as of December 31, 2018, we are dependent on the operator for operational and regulatory compliance. In addition, our oil and gas properties can become damaged, our operations may be curtailed, delayed or canceled and the costs of such operations may increase as a result of a variety of factors, including, but not limited to:

- unexpected drilling conditions, pressure conditions or irregularities in reservoir formations;
- equipment failures or accidents;
- fires, explosions, blowouts, cratering or loss of well control, as well as the mishandling or underground migration of fluids and chemicals;
- adverse weather conditions and natural disasters, such as tornadoes, earthquakes, hurricanes and extreme temperatures;
- issues with title or in receiving governmental permits or approvals;
- restricted takeaway capacity for our production, including due to inadequate midstream infrastructure or constrained downstream markets;
- environmental hazards or liabilities;
- restrictions in access to, or disposal of, water used or produced in drilling and completion operations;
- shortages or delays in the availability of services or delivery of equipment; and
- unexpected or unforeseen changes in regulatory policy, and political or public opinions.

The occurrence of one or more of these factors could result in a partial or total loss of our investment in a particular property, as well as significant liabilities. 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. For certain risks, such as political risk, business interruption, war, terrorism and piracy, we have limited or no insurance coverage. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase. The occurrence of a significant event against which we are not fully insured may expose us to liabilities.

We are subject to extensive governmental regulation and ongoing regulatory changes, which could adversely impact our business.

Our operations are subject to extensive federal, state, tribal, local and other laws, rules and regulations, including with respect to environmental matters, worker health and safety, wildlife conservation, the gathering and transportation of oil, gas and NGLs, conservation policies, reporting obligations, royalty payments, unclaimed property and the imposition of taxes. Such regulations include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling, completion and well operations. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling or completion activities, we may not be able to conduct our operations as planned. In addition, we may be required to make large, sometimes unexpected, expenditures to comply with applicable governmental laws, rules, regulations, permits or orders.

In addition, changes in public policy have affected, and in the future could further affect, our operations. Regulatory changes could, among other things, restrict production levels, impose price controls, alter environmental protection requirements and increase taxes, royalties and other amounts payable to the government. Our operating and compliance costs could increase further if existing laws and regulations are revised or reinterpreted or if new laws and regulations become applicable to our operations. We do not expect that any of these laws and regulations will affect our operations materially differently than they would affect other companies with similar operations, size and financial strength. Although we are unable to predict changes to existing laws and regulations, such changes could significantly impact our profitability, financial condition and liquidity. As is discussed below this is particularly true of changes related to pipeline safety, seismic activity, hydraulic fracturing, climate change and endangered species designations.

Pipeline Safety. The pipeline assets in which we own interests are subject to stringent and complex regulations related to pipeline safety and integrity management. The Pipeline and Hazardous Materials Safety Administration (PHMSA) has established a series of rules that require pipeline operators to develop and implement integrity management programs for gas, NGL and condensate transmission pipelines as well as certain low stress pipelines and gathering lines transporting hazardous liquids, such as oil, that, in the event of a failure, could affect "high consequence areas." Additional action by PHMSA with respect to pipeline integrity management requirements may occur in the future. For example, in 2016 PHMSA proposed new rules for gas pipelines that extend pipeline safety programs beyond high consequence areas to newly proposed "moderate consequence areas or rural areas" and would also impose more rigorous testing and reporting requirements on such pipelines. Elements of a final rulemaking, commonly referred to as the "Gas Mega Rule," continues to be deliberated by PHMSA's Gas Pipeline Advisory Committee (GPAC). To date, no final regulatory action has been taken. More recently, in January 2017, PHMSA finalized regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, leak detection and repairs), regardless of the pipeline's proximity to a high consequence area. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. Per direction provided via a "Regulatory Freeze" Memo published on January 20, 2017 by the Trump Administration, this final regulatory action was withdrawn and continues to be evaluated by executive leadership. In July 2018, PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline. At this time, we cannot predict the cost of these requirements or other potential new or amended regulations, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Seismic Activity. Earthquakes in some of our operating areas and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry. For example, the Oklahoma Corporation Commission (OCC) issued guidance to operators in the SCOOP and STACK areas for management of certain seismic activity that may be related to hydraulic fracturing activities. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation or other requirements that could lead to operational delays, increase our operating and compliance costs or otherwise adversely affect our operations. In addition, we are currently defending against certain third- party lawsuits and could be subject to additional claims, seeking damages or other remedies as a result of alleged induced seismic activity in our areas of operation.

Hydraulic Fracturing. Several states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure and/or well construction requirements on hydraulic fracturing operations. Three states (New York, Maryland and Vermont) have banned the use of high-volume hydraulic fracturing. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. There have also been certain governmental reviews that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. Governments may continue to study hydraulic fracturing. We cannot predict the outcome of future studies, but based on the results of these studies to date, federal and state legislatures and agencies may seek to further regulate or even ban hydraulic fracturing activities. In addition, if existing laws and regulations with regard to hydraulic fracturing are revised or reinterpreted or if new laws and regulations become applicable to our operations through judicial or administrative actions, our business, financial condition, results of operations and cash flows could be adversely affected. For example, a decision by a Pennsylvania state court in 2018, if upheld, could change the established common law rule of capture and apply liability to oil and gas companies for trespass when hydraulic fracturing results in the production of oil and gas from adjoining property, which may impose burdens on hydraulic fracturing in Pennsylvania that may be material.

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 potential bans. Additional regulation could also lead to greater opposition to hydraulic fracturing, including litigation.

Climate Change. Continuing political and social attention to the issue of climate change has resulted in legislative, regulatory and other initiatives to reduce greenhouse gas emissions, such as carbon dioxide and methane. Policy makers at both the U.S. federal and state levels have introduced legislation and proposed new regulations designed to quantify and limit the emission of greenhouse gases through inventories, limitations and/or taxes on greenhouse gas emissions. EPA and BLM have issued regulations for the control of methane emissions, which also include leak detection and repair requirements, for the oil and gas industry; however, following the change in presidential administrations, both agencies took actions to rescind or revise the rules. In September 2018, BLM issued a final rule that rescinded certain requirements of its venting and flaring rule. Similarly, in October 2018, EPA published a proposed rule that amends certain requirements of its methane rule. The EPA rule remains in effect. Nevertheless, several states where we operate have imposed venting and flaring limitations designed to reduce methane emissions from oil and gas exploration and production activities. Legislative and state initiatives to date have generally focused on the development of cap and trade and/or carbon tax programs. Cap and trade programs offer greenhouse gas emission allowances that are gradually reduced over time. A cap and trade program could impose direct costs on us through the purchase of allowances and could impose indirect costs by incentivizing consumers to shift away from fossil fuels. A carbon tax could directly increase our costs of operation and similarly incentivize consumers to shift away from fossil fuels.

In addition, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities.

These various legislative, regulatory and other activities addressing greenhouse gas emissions could adversely affect our business, including by imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations, which could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Limitations on greenhouse gas emissions could also adversely affect demand for oil and gas, which could lower the value of our reserves and have a material adverse effect on our profitability, financial condition and liquidity. Furthermore, increasing attention to climate change risks has resulted in increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely affect our business.

Endangered Species. The Endangered Species Act (ESA) prohibits the taking of 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 material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where we intend to conduct construction activity or the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

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

For water sourcing, Chesapeake first seeks to use non-potable water supplies for our operational needs. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must then be obtained from other sources and transported to the drilling site. An 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. The imposition of new environmental regulations could further restrict our ability to conduct operations such as hydraulic fracturing by restricting the disposal of things such as produced water and drilling fluids

Environmental matters and related costs can be significant.

As an owner, lessee or operator of oil and gas properties, we are subject to various federal, state, tribal and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on us for the cost of remediating pollution that results from our operations. Environmental laws may impose strict, joint and several liability, and the failure to comply with environmental laws and regulations can result in the imposition of administrative, civil and/or criminal fines and penalties, as well as injunctions limiting operations in affected areas. Any future costs associated with these matters are uncertain and will be governed by several factors, including future changes to regulatory requirements. Changes in or additions to public policy regarding the protection of the environment could have a significant impact on our operations and profitability.

The taxation of independent producers is subject to change, and changes in tax law could increase our cost of doing business.

We are subject to taxation by various taxing authorities at the federal, state and local levels where we do business. New legislation increasing our tax burden could be enacted by any of these governmental authorities. Recently, legislative changes imposing additional taxes or increases to existing taxes were considered in Louisiana, Oklahoma, Pennsylvania and Wyoming. It is possible that any of these states could enact new tax legislation making it more costly for us to explore for oil and natural gas resources.

The oil and gas exploration and production industry is very competitive, and some of our competitors 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 oil, natural gas or NGL. Competitors include multinational oil companies, independent production companies and individual producers and operators. Some of our competitors have greater financial and other resources than we do and, due to our debt levels and other factors, may have greater access to the capital and credit markets. As a result, these competitors may be able to address these competitive factors more effectively or weather industry downturns more easily than we can. We also face indirect competition from alternative energy sources, including wind, solar and electric power.

Our performance 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. If we are unsuccessful in attracting and retaining skilled employees and managerial talent, our ability to compete effectively may be diminished. We also compete for the equipment required to explore, develop and operate properties. Typically, during times of rising commodity prices, drilling and operating costs will also increase. During these periods, there is often a shortage of drilling rigs and other oilfield equipment and services, which could adversely affect our ability to execute our development plans on a timely basis and within budget.

Risks related to potential acquisitions or dispositions may adversely affect our business.

From time to time, we evaluate acquisitions and dispositions of assets, businesses and other investments. These transactions may not result in the anticipated benefits or efficiencies. In addition, acquisitions may be financed by borrowings, requiring us to incur more debt, or by the issuance of our common stock. Any such acquisition or disposition involves risks and we cannot assure you that:

- any acquisition would be successfully integrated into our operations and internal controls;
- the due diligence conducted prior to an acquisition would uncover situations that could result in financial or legal exposure, such as title defects and potential environmental and other liabilities;
- post-closing purchase price adjustments will be realized in our favor;
- our assumptions about, among other things, reserves, estimated production, revenues, capital expenditures, operating, operating expenses and costs would be accurate;
- any investment, acquisition, disposition or integration would not divert management resources from the operation of our business; and
- any investment, acquisition, or disposition or integration would not have a material adverse effect on our financial condition, results of operations, cash flows or reserves.

If any of these risks materialize, the benefits of such acquisition or disposition may not be fully realized, if at all, and our financial condition, results of operations, cash flows and reserves could be negatively impacted.

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

Historically, concerns about global economic growth have had a significant impact on global financial markets and commodity prices. If the economic climate in the United States 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 materially adversely impact our results of operations, liquidity and financial condition.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices, or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, waste disposal, oil spills, seismic activity, climate change, explosions of natural gas transmission lines and the development and operation of pipelines and other midstream facilities may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Additionally, environmental groups, landowners, local groups and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business.

Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in energy-related activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities.

Our operations may be adversely affected by pipeline, trucking and gathering system capacity constraints and may be subject to interruptions that could adversely affect our cash flow.

In certain resource plays, the capacity of gathering and transportation systems is insufficient to accommodate potential production from existing and new wells. We rely heavily on third parties to meet our oil, natural gas and NGL gathering needs. Capital constraints could limit the construction of new pipelines and gathering systems and the providing or expansion of trucking services by third parties. Until this new capacity is available, we may experience delays in producing and selling our oil, natural gas and NGL. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell oil, natural gas 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 oil, natural gas 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 materially adversely affect our cash flow.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we are unable to obtain and maintain adequate protection for our data, our business may be harmed.

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 oil, natural gas and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our customers, employees and third-party partners. We have been the subject of cyber-attacks on our internal systems and through those of third parties, but these incidents did not have a material adverse impact on our results of operations. Nevertheless, unauthorized access to our seismic data, reserves information, customer or employee data 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. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations, which may include drilling, completion, production and corporate functions. A cyber-attack involving our information systems and related infrastructure, or that of our business associates, could result in supply chain disruptions that delay or prevent the transportation and marketing of our production, non-compliance leading to regulatory fines or penalties, loss or disclosure of, or damage to, our or any of our customer's or supplier's data or confidential information that could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

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. In addition, new laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and potentially elevate costs, and any failure to comply with these laws and regulations could result in significant penalties and legal liability.

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 and earthquakes. Our information systems and administrative and management processes are primarily provided to our various drilling projects and producing wells 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.

We do not anticipate paying dividends on our common stock in the near future.

In July 2015, our Board of Directors determined to eliminate quarterly cash dividends on our common stock. We do not intend to resume paying cash dividends on our common stock in the foreseeable future. We currently intend to retain any earnings for the future operation and development of our business, including exploration, development and acquisition activities or to retire outstanding debt and/or preferred stock. Any future dividend payments will require approval by the Board of Directors. In addition, dividends may be restricted by the terms of our debt agreements. Additionally, our Board of Directors may determine to suspend dividend payments on our preferred stock in the future. If we fail to pay dividends on our preferred stock with respect to six or more quarterly periods (whether or not consecutive), the holders of our preferred stock, voting as a single class, will be entitled at the next regular or special meeting of shareholders to elect two additional directors of the Company. We had previously failed to pay dividends on our outstanding preferred stock with respect to four quarterly periods during the fiscal year ended December 31, 2016, before resuming payment, in arrears, in the first quarter of 2017.

Certain anti-takeover and other provisions may affect your rights as a shareholder.

Our certificate of incorporation authorizes our Board of Directors to set the terms of and issue preferred stock without shareholder approval. Our Board of Directors could use the preferred stock as a means to delay, defer or prevent a takeover attempt that a shareholder might consider to be in our best interest. In addition, our revolving credit facilities, preferred stock and certain of our notes contain terms that may restrict our ability to enter into change of control transactions, including requirements to repay borrowings under our revolving credit facilities and to offer to repurchase such notes on a change in control. These provisions, along with specified provisions of the Oklahoma General Corporation Act and our certificate of incorporation and bylaws, may discourage or impede transactions involving actual or potential changes in our control, including transactions that otherwise could involve payment of a premium over prevailing market prices to holders of our common stock.

Risks Associated with Acquisition of WildHorse

The WildHorse Merger may not be accretive, and may be dilutive, to our earnings per share, which may negatively affect the market price of shares on our common stock.

In connection with the completion of the WildHorse Merger, we issued approximately 717.3 million shares of our common stock. The issuance of these new shares of our common stock could have the effect of depressing the market price of shares of our common stock, through dilution of earnings per share or otherwise. Any dilution of, or delay of any accretion to, our earnings per share could cause the price of shares of our common stock to decline or increase at a reduced rate.

The market price of shares of our common stock may decline in the future as a result of the sale of shares of our common stock held by former WildHorse stockholders or current stockholders.

Former WildHorse stockholders may, following 60- and 180-day lock-up periods for certain primary former WildHorse stockholders following the closing date of the WildHorse Merger, seek to sell the shares of our common stock delivered to them following the consummation of the WildHorse Merger. Other shareholders may also seek to sell shares of our common stock held by them following, or in anticipation of, completion of the WildHorse Merger. In addition, we have granted certain stockholders of WildHorse registration rights with respect to the shares of our common stock they receive in the WildHorse Merger. These sales (or the perception that these sales may occur), coupled with the increase in the outstanding number of shares of our common stock, may affect the market for, and the market price of, our common stock in an adverse manner.

We may fail to realize all of the anticipated benefits of the WildHorse Merger.

The success of the WildHorse Merger will depend, in part, on our ability to realize the anticipated benefits and cost savings from combining our and WildHorse's businesses, including operational and other synergies that we believe the combined company will achieve. We expect that the WildHorse Merger will provide substantial cost savings with $200 million to $280 million in projected average annual savings, totaling $1 billion to $1.5 billion by 2023, due to operational and capital efficiencies as a result of Chesapeake's significant expertise with unconventional assets and technical and operational excellence. The anticipated benefits and cost savings of the WildHorse Merger may not be realized fully or at all, may take longer to realize than expected or could have other adverse effects that we do not currently foresee. Some of the assumptions that we have made, such as the achievement of operational cost savings, may not be realized. The integration process may, for us and WildHorse, result in the loss of key employees, the disruption of ongoing businesses or inconsistencies in standards, controls, procedures and policies. There could be potential unknown liabilities and unforeseen expenses associated with the WildHorse Merger that were not discovered in the course of performing due diligence. The integration will require significant time and focus from management following the acquisition.

We will incur substantial transaction fees and costs in connection with the WildHorse Merger.

We expect to incur a number of non-recurring transaction-related costs associated with completing the WildHorse Merger. These fees and costs may be substantial. Non-recurring transaction costs include, but are not limited to, fees paid to legal, financial and accounting advisors, filing fees and printing costs.

The issuance of our common stock to shareholders of WildHorse as well as other stock transactions could lead to a limitation on the utilization of our loss carryforwards to reduce future taxable income.

Our ability to utilize U.S. net operating loss carryforwards (NOL) to reduce future taxable income and federal income tax is subject to various limitations under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"). The utilization of such carryforwards may be limited under Section 382 of the Code upon the occurrence of ownership changes resulting from issuances of our stock or the sale or exchange of our stock by certain shareholders if, as a result, there is a cumulative change of more than 50% in the beneficial ownership of our stock during any three-year period. For this purpose, "stock" includes certain preferred stock. In the event of such an ownership change, Section 382 of the Code imposes an annual limitation on the amount of our loss carryforwards that can be used to offset taxable income. The limitation is generally equal to the product of (a) the fair market value of our equity multiplied by (b) the long-term tax-exempt rate in effect for the month in which an ownership change occurs. If we are in a net unrealized built-in gain position at the time of an ownership change, then the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains inherent in the assets sold. If we are in a net unrealized built-in loss position at the time of an ownership change, then the limitation may apply to tax attributes other than just loss carryforwards, such as depreciable basis of tangible equipment. Some states impose similar limitations on tax attribute utilization upon experiencing an ownership change. We do not believe we have a limitation on the ability to utilize our U.S. loss carryforwards and other tax attributes under Section 382 of the Code as of December 31, 2018. We further believe that the WildHorse Merger did not result in an ownership change based on information currently available. However, issuances, sales and/or exchanges of our stock (including, potentially, relatively small transactions and transactions beyond our control) occurring after December 31, 2018, taken together with prior transactions with respect to our stock and the WildHorse Merger, could trigger an ownership change under Section 382 of the Code and therefore a limitation on our ability to utilize our U.S. loss carryforwards and other tax attributes. Any such limitation could cause some loss carryforwards to expire before we would be able to utilize them to reduce taxable income in future periods, possibly resulting in a substantial income tax expense or write down of our tax assets or both.

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 Part II of this report.

ITEM 3. *Legal Proceedings*

Litigation and Regulatory Proceedings

We are 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 or may seek damages and penalties, the amount of which is currently indeterminate. See Note 4 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for information regarding our estimation and provision for potential losses related to litigation and regulatory proceedings.

Business Operations. We are involved in various lawsuits and disputes incidental to our business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions.

Regarding royalty claims, we and other natural gas producers have been named in various lawsuits alleging royalty underpayments. The lawsuits against us allege, among other things, that we used below-market prices, made improper deductions, utilized improper measurement techniques, entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL, or similar theories. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The lawsuits seek compensatory, consequential, treble, and punitive damages, restitution and disgorgement of profits, declaratory and injunctive relief regarding our royalty payment practices, pre-and post-judgment interest, and attorney's fees and costs. Plaintiffs have varying royalty provisions in their respective leases, oil and gas law varies from state to state, and royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations. We have resolved a number of these claims through negotiated settlements of past and future royalty obligations and have prevailed in various other lawsuits. We are currently defending numerous lawsuits seeking damages with respect to underpayment of royalties in multiple states where we have operated, including the matters set forth below.

On December 9, 2015, the Commonwealth of Pennsylvania, by the Office of Attorney General, filed a lawsuit in the Bradford County Court of Common Pleas related to royalty underpayment and lease acquisition and accounting practices with respect to properties in Pennsylvania. The lawsuit, which primarily relates to the Marcellus Shale and Utica Shale, alleges that we violated the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL) by making improper deductions and entering into arrangements with affiliates that resulted in underpayment of royalties. The lawsuit includes other UTPCPL claims and antitrust claims, including that a joint exploration agreement to which we are a party established unlawful market allocation for the acquisition of leases. The lawsuit seeks statutory restitution, civil penalties and costs, as well as a temporary injunction from exploration and drilling activities in Pennsylvania until restitution, penalties and costs have been paid, and a permanent injunction from further violations of the UTPCPL.

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of our divestiture of substantially all of our midstream business and most of our gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights, intentional interference with contractual relations, and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources. These lawsuits seek in aggregate compensatory, consequential, treble, and punitive damages, restitution and disgorgement of profits, declaratory and injunctive relief regarding our royalty payment practices, pre-and post-judgment interest, and attorney's fees and costs. On December 20, 2017 and August 9, 2018, we reached tentative settlements to resolve substantially all Pennsylvania civil royalty cases for a total of approximately $35 million.

We also previously disclosed defending lawsuits alleging various violations of the Sherman Antitrust Act and state antitrust laws. In 2016, putative class action lawsuits were filed in the U.S. District Court for the Western District of Oklahoma and in Oklahoma state courts, and an individual lawsuit was filed in the U.S. District Court of Kansas, in each case against us and other defendants. The lawsuits generally allege that, since 2007 and continuing through April 2013, the defendants conspired to rig bids and depress the market for the purchases of oil and natural gas leasehold interests and properties in the Anadarko Basin containing producing oil and natural gas wells. The lawsuits seek damages, attorney's fees, costs and interest, as well as enjoinment from adopting practices or plans that would restrain competition in a similar manner as alleged in the lawsuits. On April 12, 2018, we reached a tentative settlement to resolve substantially all Oklahoma civil class action antitrust cases for an insignificant amount. The final fairness hearing is set for April 25, 2019.

On July 28, 2017, OOGC America LLC (OOGC) filed a demand for arbitration with the American Arbitration Association against Chesapeake Exploration, L.L.C., our wholly owned subsidiary, in connection with OOGC's purchase of certain oil and gas leases and other assets pursuant to a Purchase and Sale Agreement entered into on October 10, 2010. In connection with the sale, we also entered into a Development Agreement with OOGC, dated November 15, 2010 (the "Development Agreement"), which governs each of our rights and obligations with respect to the sale, including the transportation and marketing of oil and gas. OOGC's breach of contract, breach of agency and fiduciary duties and other claims generally alleged, among other things, that we subjected OOGC to excessive rates for gathering and other services provided for under the Development Agreement and interfered with OOGC's right to audit the documents that supported those rates. On November 13, 2018, a unanimous panel denied every claim asserted by OOGC other than OOGC being entitled to a declaration clarifying its audit rights.

On July 24, 2018, Healthcare of Ontario Pension Plan (HOOPP) filed a demand for arbitration with the American Arbitration Association regarding HOOPP's purchase of our interest in Chaparral Energy, Inc. stock for $215 million on January 5, 2014. HOOPP claims that we engaged in material misrepresentations and fraud, and that we violated the Exchange Act and Oklahoma Uniform Securities Act. HOOPP seeks either rescission or $215 million in monetary damages, and in either case, interest, attorney's fees, disgorgement and punitive damages. We intend to vigorously defend these claims.

In February 2019, a putative class action lawsuit in the District Court of Dallas County, Texas was filed against FTS International, Inc. ("FTSI"), certain investment banks, FTSI's directors including certain of our officers and certain shareholders of FTSI including us. The lawsuit alleges various violations of Sections 11 (with respect to certain of our officers in their capacities as directors of FTSI) and 15 (with respect to such officers and us) of the Securities Act of 1933 in connection with public disclosure made during the initial public offering of FTSI. The suit seeks damages in excess of $1,000,000 and attorneys' fees and other expenses. We intend to vigorously defend these claims.

Environmental Proceedings

Our subsidiary Chesapeake Appalachia, LLC (CALLC) is engaged in discussions with the EPA, the U.S. Army Corps of Engineers and the Pennsylvania Department of Environmental Protection (PADEP) regarding potential violations of the permitting requirements of the federal Clean Water Act (CWA), the Pennsylvania Clean Streams Law and the Pennsylvania Dam Safety and Encroachments Act in connection with the placement of dredge and fill material during construction of certain sites in Pennsylvania. CALLC identified the potential violations in connection with an internal review of its facilities siting and construction processes and voluntarily reported them to the regulatory agencies. Resolution of the matter may result in monetary sanctions of more than $100,000.

We are also in discussions with PADEP regarding gas migration in the vicinity of certain of our wells in Bradford County, Pennsylvania. We believe we are close to identifying agreed-upon steps to resolve PADEP's concerns regarding the issue.

On December 27, 2016, we received a Finding of Violation from the EPA alleging violations of the CAA at a number of locations in Ohio. We have exchanged information with the EPA and are engaged in discussions aimed at resolving the allegations. Resolution of the matter may result in monetary sanctions of more than $100,000. We received another Finding of Violation from EPA on December 20, 2018 alleging violations of the CAA and violations of the Ohio State Implementation Plan at a number of our Ohio facilities. We have begun discussions with EPA aimed at resolving the allegations. Resolution of this matter may result in monetary sanctions of more than $100,000.

We are named as a defendant in numerous lawsuits in Oklahoma alleging that we and other companies have engaged in activities that have caused earthquakes. These lawsuits seek compensation for injury to real and personal property, diminution of property value, economic losses due to business interruption, interference with the use and enjoyment of property, annoyance and inconvenience, personal injury and emotional distress. In addition, they seek the reimbursement of insurance premiums and the award of punitive damages, attorneys' fees, costs, expenses and interest.

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***

Common Stock

Our common stock trades on the New York Stock Exchange under the symbol "CHK".

Shareholders

As of February 12, 2019, there were approximately 2,000 holders of record of our common stock and approximately 307,000 beneficial owners.

Dividends

We ceased paying dividends on our common stock in the 2015 third quarter and do not intend to resume paying cash dividends on our common stock in the foreseeable future. Our revolving credit facility and the certificates of designation for our preferred stock contain restrictions 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. After suspending the payment of dividends on our outstanding convertible preferred stock during fiscal year 2016, we reinstated the payment of dividends on each series of our outstanding convertible preferred stock beginning with the dividends payable in the 2017 first quarter and paid all dividends in arrears.

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, 2018:

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 Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs[b]
				($ in millions)
October 1, 2018 through October 31, 2018	10,989	$ 4.60	—	$ 1,000
November 1, 2018 through November 30, 2018	—	$ —	—	$ 1,000
December 1, 2018 through December 31, 2018	—	$ —	—	$ 1,000
Total	10,989	$ —	—	

(a) Includes shares of common stock purchased on behalf of our deferred compensation plan.

(b) In December 2014, our Board of Directors authorized the repurchase of up to $1 billion of our common stock from time to time. The repurchase program does not have an expiration date. As of December 31, 2018, there have been no repurchases under the program.

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

The following table sets forth selected consolidated financial data of Chesapeake as of and for the years ended December 31, 2018, 2017, 2016, 2015 and 2014. The data are derived from our audited consolidated financial statements. The table below 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,				
	2018	2017	2016	2015	2014
	($ in millions, except per share data)				
STATEMENT OF OPERATIONS DATA:					
Total revenues	$ 10,231	$ 9,496	$ 7,872	$ 12,764	$ 23,125
Net income (loss) available to common stockholders[(a)]	$ 775	$ 813	$ (4,915)	$(14,738)	$ 1,273
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ 0.85	$ 0.90	$ (6.43)	$ (22.26)	$ 1.93
Diluted	$ 0.85	$ 0.90	$ (6.43)	$ (22.26)	$ 1.87
CASH DIVIDEND DECLARED PER COMMON SHARE	$ —	$ —	$ —	$ 0.0875	$ 0.35
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 10,947	$ 12,425	$ 13,028	$ 17,314	$ 40,655
Long-term debt, net of current maturities	$ 7,341	$ 9,921	$ 9,938	$ 10,311	$ 11,058
Total equity (deficit)	$ 467	$ (372)	$ (1,203)	$ 2,397	$ 18,205

(a) Includes $2.564 billion and $18.238 billion of full cost ceiling test write-downs on our oil and natural gas properties for the years ended December 31, 2016 and 2015, respectively. In 2018, 2017 and 2014, we did not have any ceiling test impairments on our oil and natural gas properties.

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

Overview

The following discussion and analysis presents management's perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with "Item 8. Financial Statements and Supplementary Data" of this report.

The transformation of Chesapeake over the past five years has been significant and our progress accelerated in 2018 and early 2019. We believe our recent accomplishments and achievements have made our company stronger. Highlights include the following:

- acquired WildHorse, an oil and gas company with operations in the Eagle Ford Shale and Austin Chalk formations in southeast Texas, for approximately 717.3 million shares of our common stock and $381 million in cash, and the assumption of WildHorse's debt of $1.4 billion as of February 1, 2019. We anticipate the acquisition to materially increase our oil production and enhance our oil production mix as well as significantly reduce costs due to operational synergies that we believe the combined company will achieve. We expect that the WildHorse Merger will provide substantial cost savings with $200 million to $280 million in projected average annual savings, totaling $1 billion to $1.5 billion by 2023, due to operational and capital efficiencies as a result of Chesapeake's significant expertise with unconventional assets and technical and operational excellence;
- sold our interests in the Utica Shale operating area located in Ohio for approximately $1.9 billion, and used the proceeds to reduce outstanding debt by approximately $1.8 billion, including our senior secured second lien notes;
- retired our secured term loan due 2021 and significantly extended our debt maturity profile by issuing at par $850 million of 7.00% Senior Notes due 2024 and $400 million of 7.50% Senior Notes due 2026 for net proceeds of $1.2 billion, reducing our annual cash interest by approximately $30 million based on interest rates at the time of retirement;
- continued to simplify our balance sheet, by repurchasing the CHK Utica, L.L.C. investors' overriding royalty interests (ORRI) for $199 million;
- improved liquidity by amending and restating our Chesapeake revolving credit facility, extending its maturity date by approximately four years;
- improved cash flow from operations by $1.3 billion;
- improved our cost structure by reducing our production, general and administrative, and gathering, processing and transportation expenses by $78 million, or 3%; and
- generated approximately $528 million in proceeds from the disposition of certain non-core assets and other property sales in addition to the sale of our Utica Shale properties.

Looking forward into 2019, we are confident in our ability to drive further competitive performance through the quality of our investments and our capital and operating discipline. We have secured a strong hedge position for oil and natural gas that provides stability and certainty in our cash generating capability should commodity prices experience volatility.

In 2019, our focus remains concentrated on four strategic priorities:

- reduce total leverage to achieve long term net debt/EBITDA of 2x;
- increase net cash provided by operating activities to fund capital expenditures;
- improve margins through financial discipline and operating efficiencies; and
- maintain industry leading environmental and safety performance.

Business and Industry Outlook

Over the past decade, the landscape of energy production has changed dramatically in the United States. Domestic energy production capabilities have increased the nation's supply of both crude oil and natural gas, primarily driven by advances in technology, horizontal drilling and hydraulic fracture stimulation techniques. As a result of this increase in domestic supply of crude oil and natural gas, commodity prices for these products are meaningfully lower than they were a decade ago, and may remain volatile for the foreseeable future.

We have undergone a mutli-year effort to reduce our cost structure significantly and improve the profitability of our upstream portfolio. We have sold our non-upstream businesses, assets in under-performing basins and reduced our operating and general and administrative costs such that we are currently experiencing higher profitability than compared to periods when commodity prices were much higher. The improvements in our cost structure give us a strategic advantage as a low cost developer of unconventional oil and gas assets in the U.S. We recently used this strategic advantage to successfully acquire Wildhorse, a single asset, oil-focused company with an attractive acreage position of high-margin, undrilled locations. Our strategy going forward will be to leverage our advantages to drive shareholder value by growing cash flow through the development of our extensive portfolio of drilling opportunities. We intend to maintain capital discipline as we target cash flow growth rates that can be sustainable with internally generated resources.

Liquidity and Capital Resources

Liquidity Overview

Our ability to grow, make capital expenditures and service our debt depends primarily upon the prices we receive for the oil, natural gas and NGL we sell. Substantial expenditures are required to replace reserves, sustain production and fund our business plans. Historically, oil and natural gas prices have been volatile, and may be subject to wide fluctuations in the future. A decline in oil, natural gas and NGL prices could negatively affect the amount of cash we generate and have available for capital expenditures and debt service and could have a material impact on our financial position, results of operations, cash flows and on the quantities of reserves that we can economically produce or provide as collateral to our credit facility lenders. Other risks and uncertainties that could affect our liquidity include, but are not limited to, counterparty credit risk for our receivables, access to capital markets, regulatory risks and our ability to meet financial covenants in our financing agreements.

Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facilities, we expect to be able to fund our planned capital expenditures, meet our debt service requirements and fund our other commitments and obligations for the next 12 months.

As of December 31, 2018, we had a cash balance of $4 million compared to $5 million as of December 31, 2017, and a net working capital deficit of $1.230 billion as of December 31, 2018, compared to a net working capital deficit of $831 million as of December 31, 2017. As of December 31, 2018, our working capital deficit includes $381 million of debt due in the next 12 months. Our total principal debt as of December 31, 2018 was $8.168 billion compared to $9.981 billion as of December 31, 2017. As of December 31, 2018, we had $2.474 billion of borrowing capacity available under the Chesapeake revolving credit facility, with outstanding borrowings of $419 million and $107 million utilized for various letters of credit. As of the WildHorse acquisition date of February 1, 2019, we had $578 million of borrowing capacity available under the WildHorse revolving credit facility, with outstanding borrowings of $675 million and $47 million utilized as a letter of credit. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our debt obligations, including principal and carrying amounts of our notes.

Although we have taken measures to mitigate liquidity concerns over the next 12 months, as outlined above in *Overview*, there can be no assurance that these measures will be sufficient for periods beyond the next 12 months. If needed, we may seek to access the capital markets or otherwise refinance a portion of our outstanding indebtedness to improve our liquidity. We closely monitor 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 revolving credit facilities. Furthermore, our ability to generate operating cash flow in the current commodity price environment, sell assets, access capital markets or take any other action to improve our liquidity and manage our debt is subject to the risks discussed above and the other risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time or control.

Derivative and Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Our oil, natural gas and NGL derivative activities, when combined with our sales of oil, natural gas and NGL, allow us to predict with greater certainty the total revenue we will receive.

We utilize various oil, natural gas and NGL derivative instruments to protect a portion of our cash flow against downside risk. As of February 22, 2019, including January and February derivative contracts that have settled, approximately 63% of our forecasted oil, natural gas and NGL production revenue was hedged, including 56% and 81% of our forecasted 2019 oil and natural gas production (including WildHorse production from February 1, 2019) at average prices of $57.12 per barrel and $2.85 per mcf, respectively.

Oil Derivatives[(a)]

Year	Type of Derivative Instrument	Notional Volume	Average NYMEX Price
		(mmbbls)	
2019	Swaps	17	$57.16
2019	Two-way collars	6	$58.00/$67.75
2019	Basis protection swaps	7	$6.01
2019	Puts	2	$53.83
2020	Swaps	7	$58.28
2020	Two-way collars	2	$65.00/$83.25

Natural Gas Derivatives[(a)]

Year	Type of Derivative Instrument	Notional Volume	Average NYMEX Price
		(bcf)	
2019	Swaps	453	$2.87
2019	Two-way collars	55	$2.75/$3.02
2019	Three-way collars	88	$2.50/$2.80/$3.10
2019	Calls	22	$12.00
2019	Basis protection swaps	50	($0.56)
2020	Swaps	217	$2.75
2020	Call swaptions	106	$2.77
2020	Calls	22	$12.00

(a) Includes amounts settled in January and February 2019.

See Note 13 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of derivatives and hedging activities.

Debt

We decreased our total principal amount of debt outstanding by approximately $1.8 billion in 2018. We accomplished this primarily by using the net proceeds from the sale of our Utica interests and other assets. We currently plan to use cash flow from operations and availability under our credit facilities to fund our capital expenditures for 2019. We are seeking to reduce cash costs (production, gathering, processing and transportation, general and administrative and interest expenses), improve our production volumes from existing wells, and achieve additional operating and capital efficiencies with a focus on growing our oil volumes.

In 2018, we issued at par $850 million of 7.00% Senior Notes due 2024 (the “2024 notes”) and $400 million of 7.50% Senior Notes due 2026 (the “2026 notes” and, together with the 2024 notes, the “senior notes”) pursuant to a public offering for net proceeds of approximately $1.236 billion. We may redeem some or all of the 2024 notes at any time prior to April 1, 2021 and some or all of the 2026 notes at any time prior to October 1, 2021, in each case at a price equal to 100% of the principal amount of the notes to be redeemed plus a “make-whole” premium.

We used the net proceeds from the senior notes, together with cash on hand and borrowings under the Chesapeake revolving credit facility, to repay in full $1.233 billion of borrowings under our secured term loan due 2021 for $1.285 billion, which included a $52 million make-whole premium. We recorded a loss of approximately $65 million associated with the repayment of the term loan, including the make-whole premium and the write-off of $13 million of associated deferred charges. Also in 2018, we used the proceeds from the sale of our Utica assets in Ohio to redeem all of the $1.416 billion aggregate principal amount outstanding of our 8.00% Senior Secured Second Lien Notes due 2022 which included a $60 million make-whole premium. We recorded a gain of approximately $331 million associated with the redemption, including the realization of the remaining $391 million difference in principal and book value due to troubled debt restructuring accounting in 2015, offset by the make-whole premium of $60 million.

We may continue to use a combination of cash, borrowings and issuances of our common stock or other securities to retire our outstanding debt, including any debt assumed in connection with the completion with the WildHorse acquisition, through privately negotiated transactions, open market repurchases, redemptions, tender offers or otherwise, but we are under no obligation to do so. We expect to generate additional liquidity with proceeds from future sales of assets that do not fit our strategic priorities.

Chesapeake Revolving Credit Facility

The Chesapeake revolving credit facility is currently subject to a $3.0 billion borrowing base that matures in September 2023. As of December 31, 2018, we had $2.474 billion of borrowing capacity available under the Chesapeake revolving credit facility. Our next borrowing base redetermination is scheduled for the second quarter of 2019. As of December 31, 2018, we had outstanding borrowings of $419 million under the Chesapeake revolving credit facility and had used $107 million of the Chesapeake revolving credit facility for various letters of credit. Borrowings under the facility bear interest at a variable rate. Under the Chesapeake revolving credit facility, we borrowed $11.697 billion and repaid $12.059 billion in 2018, we borrowed $7.771 billion and repaid $6.990 billion in 2017 and we borrowed and repaid $5.146 billion in 2016. 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 the Chesapeake revolving credit facility. As of December 31, 2018, we were in compliance with all applicable financial covenants under the credit agreement. Our leverage ratio was approximately 3.31 to 1.00. Our secured leverage ratio and fixed charge coverage ratio were not in effect for the quarter ended December 31, 2018, due to the Utica Shale divestiture taking place during the quarter. Both ratios, in addition to the leverage ratio, will be in effect for the quarter ending March 31, 2019.

WildHorse Revolving Credit Facility

In connection with the acquisition of WildHorse, our subsidiary Brazos Valley Longhorn became the borrower under the WildHorse revolving credit facility. The WildHorse revolving credit facility has a maximum credit amount of $2.0 billion, with current aggregate elected commitments of $1.3 billion and a current borrowing base of $1.3 billion. The WildHorse revolving credit facility matures in December 2021. The borrowing base under the WildHorse revolving credit facility is subject to redetermination, on at least a semi-annual basis, primarily on estimated proved reserves. The next scheduled redetermination is in the second quarter of 2019. As of the WildHorse acquisition date of February 1, 2019, we had $578 million of borrowing capacity available under the WildHorse revolving credit facility, with outstanding borrowings of $675 million and $47 million utilized as a letter of credit. The WildHorse revolving credit facility is guaranteed by certain of Brazos Valley Longhorn’s subsidiaries (the “BVL Guarantors”) and is required to be secured by substantially all of the assets of Brazos Valley Longhorn and BVL Guarantors, including mortgages on not less than 85% of the proved reserves of their oil and gas properties.

The obligations under the WildHorse revolving credit facility are the senior secured obligations of Brazos Valley Longhorn and the BVL Guarantors. The obligations under the WildHorse revolving credit facility will not be obligations of Chesapeake or any of its subsidiaries other than Brazos Valley Longhorn and the BVL Guarantors. The obligations under the WildHorse revolving credit facility will rank equally in right of payment with all other senior secured indebtedness of Brazos Valley Longhorn and the other BVL Guarantors, and will be effectively senior to Brazos Valley Longhorn’s and the BVL Guarantors’ senior unsecured indebtedness, including their obligations under the WildHorse senior notes, to the extent of the value of the collateral securing the WildHorse revolving credit facility.

The Wildhorse revolving credit facility is used for the liquidity and expenses of Brazos Valley Longhorn and its subsidiaries and not Chesapeake or any of its subsidiaries other than Brazos Valley Longhorn, Brazos Valley Longhorn Finance Corp. ("BVL Finance Corp.") and the other BVL Guarantors. Revolving loans under the WildHorse revolving credit facility bear interest at the alternate base rate, Eurodollar rate or LIBOR market index rate at Brazos Valley Longhorn's election, plus an applicable margin (ranging from 0.50%-1.50% per annum for alternate base rate loans, 1.50%-2.50% per annum for Eurodollar loans and 1.50%-2.50% per annum for LIBOR market index rate loans), depending on Brazos Valley Longhorn's total commitment usage. The unused portion of the total commitments are subject to a commitment fee that varies from 0.375% to 0.500%, depending on Brazos Valley Longhorn's total commitment usage. The terms of the WildHorse revolving credit facility include covenants limiting, among other things, the ability of Brazos Valley Longhorn and its Restricted Subsidiaries (as defined under the WildHorse revolving credit facility) to incur additional indebtedness, make investments or loans, incur liens, consummate mergers or similar fundamental changes, make restricted payments, including dividends to Chesapeake, and enter into transactions with affiliates, including Chesapeake and its other subsidiaries. The WildHorse revolving credit facility also contains financial covenants that require Brazos Valley Longhorn to maintain (i)(x) if there are no loans outstanding thereunder, a ratio of net debt to EBITDAX (as defined under the WildHorse revolving credit facility) of not more than 4.00 to 1.00 as of the last day of each fiscal quarter or (y) if there are such loans outstanding, a ratio of total debt to EBITDAX of not more than 4.00 to 1.00 as of the last day of each fiscal quarter and (ii) a ratio of current assets (including availability under the WildHorse revolving credit facility) to current liabilities of not less than 1.00 to 1.00 as of the last day of each fiscal quarter. As of December 31, 2018, WildHorse was in compliance with all applicable financial covenants under the credit agreement. WildHorse's ratio of net debt to EBITDAX was 1.81 to 1.00 and our ratio of current assets was 4.30 to 1.00 as of December 31, 2018.

The WildHorse revolving credit facility includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; defaults with respect to indebtedness in an aggregate principal amount of $25.0 million or more; bankruptcy; judgments involving liability of $15.0 million or more that are not paid; change of control; and ERISA events. Many events of default are subject to customary notice and cure periods.

WildHorse Senior Notes

As a result of the completion of the acquisition of WildHorse, Brazos Valley Longhorn assumed the obligations under WildHorse's $700 million aggregate principal amount of 6.875% Senior Notes due 2025 (the "WildHorse senior notes") and BVL Finance Corp., a wholly owned subsidiary of Brazos Valley Longhorn, became a co-issuer of the WildHorse senior notes.

The WildHorse senior notes are the senior unsecured obligations of Brazos Valley Longhorn, BVL Finance Corp. and the other BVL Guarantors. The WildHorse senior notes will not be obligations of Chesapeake or any of its subsidiaries other than Brazos Valley Longhorn, BVL Finance Corp. and the other BVL Guarantors. The WildHorse senior notes will rank equally in right of payment with all other senior unsecured indebtedness of Brazos Valley Longhorn, BVL Finance Corp. and the other BVL Guarantors, and will be effectively subordinated to Brazos Valley Longhorn's, BVL Finance Corp.'s and the other BVL Guarantors' senior secured indebtedness, including their obligations under the WildHorse revolving credit facility, to the extent of the value of the collateral securing such indebtedness.

The indenture (the "WildHorse indenture") governing the WildHorse senior notes contains customary reporting covenants (including furnishing quarterly and annual reports to the holders of the WildHorse senior notes) and restrictive covenants that, among other things, restrict the ability of Brazos Valley Longhorn and its subsidiaries to: (i) pay dividends on, purchase or redeem Brazos Valley Longhorn's equity interests or purchase or redeem subordinated debt; (ii) make certain investments; (iii) incur or guarantee additional indebtedness or issue certain types of equity securities; (iv) create or incur certain secured debt; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of Brazos Valley Longhorn's assets; (vii) enter into agreements that restrict distributions or other payments from Brazos Valley Longhorn's restricted subsidiaries to Brazos Valley Longhorn; (viii) engage in transactions with affiliates, including Chesapeake and its other subsidiaries; and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important qualifications and limitations. In addition, most of the covenants will be terminated before the WildHorse senior notes mature if at any time no default or event of default exists under the WildHorse indenture and the WildHorse senior notes receive an investment grade rating from both of two specified ratings agencies. The WildHorse indenture also contains customary events of default.

If the WildHorse senior notes are downgraded within 90 days after the consummation of the acquisition of WildHorse (which constitutes a “Change of Control” under the WildHorse indenture), the WildHorse indenture requires Brazos Valley Longhorn (or a third party, in certain circumstances) to make an offer to repurchase the WildHorse senior notes at 101% of their principal amount, plus accrued and unpaid interest, within 30 days of such downgrade. If any holder of WildHorse senior notes accepts such offer, Brazos Valley Longhorn may (subject to the terms and conditions thereof) fund the purchase price with loans under the WildHorse revolving credit facility or Chesapeake may elect to draw under the Chesapeake revolving credit facility, use cash on hand, issue debt securities or use other sources of liquidity to fund such repurchase. If Brazos Valley Longhorn and Chesapeake are not required to make such offer or not all holders of WildHorse senior notes accept such an offer, Chesapeake may seek to amend, engage in liability management transactions with respect to, or redeem or refinance, the WildHorse senior notes at any time.

The WildHorse revolving credit facility and the WildHorse Indenture constrain the ability of WildHorse and its subsidiaries to make distributions or otherwise provide funds to, or guarantee the obligations of, Chesapeake and its other subsidiaries. The provisions of the WildHorse revolving credit facility and the WildHorse Indenture require that all transactions between WildHorse and its subsidiaries, on the one hand, and Chesapeake and its other subsidiaries, on the other hand, be on an arm's-length basis

Contractual Obligations and Off-Balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to contractual obligations and off-balance sheet commitments. The table below summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2018:

	Payments Due By Period				
	Total	**2019**	**2020-2021**	**2022-2023**	**2024 and Beyond**
			($ in millions)		
Long-term debt:[a]					
Principal[b]	$ 8,168	$ 381	$ 1,479	$ 1,208	$ 5,100
Interest	3,058	523	942	793	800
Capital lease obligation[c]	30	10	20	—	—
Operating lease obligations[d]	4	3	1	—	—
Operating commitments[e]	5,786	837	1,467	1,051	2,431
Unrecognized tax benefits[f]	53	—	—	53	—
Standby letters of credit	107	107	—	—	—
Other	18	4	8	6	—
Total contractual cash obligations[g]	$ 17,224	$ 1,865	$ 3,917	$ 3,111	$ 8,331

(a) We assumed $1.4 billion of debt with the completion of the WildHorse acquisition on February 1, 2019 that is not included in the table above.

(b) See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our long-term debt.

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

(d) 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.

(e) See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our gathering, processing and transportation agreements and service contract commitments.

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

(g) This table does not include derivative liabilities or the estimated discounted liability for future dismantlement, abandonment and restoration costs of oil and natural gas properties. See Notes 13 and 21, respectively, of the notes to our consolidated financial statements included in Item 8 of this report for more information on our derivatives and asset retirement obligations. 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 in Note 14 of the notes to our consolidated financial statements included in Item 8 of this report.

Capital Expenditures

Our 2019 capital expenditures program is expected to generate greater capital efficiency than the 2018 program as we focus on expanding our margins through disciplined investing in the highest-return projects. We have significant control and flexibility over the timing and execution of our development plan, enabling us to reduce our capital spending as needed. Our forecasted 2019 capital expenditures, inclusive of Brazos Valley and capitalized interest, are $2.3 – $2.5 billion compared to our 2018 capital spending level of $2.4 billion. Management continues to review operational plans for 2019 and beyond, which could result in changes to projected capital expenditures and projected revenues from sales of oil, natural gas and NGL.

Credit Risk

Derivative instruments that enable us to manage our exposure to oil, natural gas and NGL prices expose us to credit risk from our counterparties. To mitigate this risk, we enter into oil, natural gas and NGL derivative contracts only with counterparties that we deem to have acceptable credit strength and are 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, 2018, our oil, natural gas and NGL derivative instruments were spread among 11 counterparties. Additionally, the counterparties under these arrangements are required to secure their obligations in excess of defined thresholds.

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL ($976 million as of December 31, 2018) and exploration and production companies that own interests in properties we operate ($211 million as of December 31, 2018). 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 deemed to have sub-standard credit, unless the credit risk can otherwise be mitigated. During 2018, 2017 and 2016, we recognized $6 million, $9 million and $10 million, respectively, of bad debt expense related to potentially uncollectible receivables.

Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as gathering, processing, transportation and hedging agreements. As of February 22, 2019, we have received requests and posted approximately $162 million of collateral related to certain of our marketing and other contracts. We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $355 million, which may be in the form of additional letters of credit, cash or other acceptable collateral. However, we have substantial long-term business relationships with each of these counterparties, and we may be able to mitigate any collateral requests through ongoing business arrangements and by offsetting amounts that the counterparty owes us. Any posting of collateral consisting of cash or letters of credit reduces availability under our revolving credit facility and negatively impacts our liquidity.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the years ended December 31, 2018, 2017 and 2016. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of divestitures of oil and natural gas assets.

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Cash provided by (used in) operating activities	$ 2,000	$ 745	$ (204)
Proceeds from issuances of debt, net	1,236	1,585	3,686
Proceeds from revolving credit facility borrowings, net	—	781	—
Proceeds from divestitures of proved and unproved properties, net	2,231	1,249	1,406
Proceeds from sales of other property and equipment, net	147	55	131
Proceeds from sales of investments	74	—	—
Total sources of cash and cash equivalents	$ 5,688	$ 4,415	$ 5,019

Cash Flow from Operating Activities

Cash provided by operating activities was $2.000 billion in 2018 compared to cash provided by operating activities of $745 million in 2017 and cash used in operating activities of $204 million in 2016. The increase in 2018 is primarily the result of higher prices for the oil, natural gas and NGL we sold. The increase in 2017 is primarily the result of higher prices for the oil, natural gas and NGL we sold and decreases in certain of our operating expenses, partially offset by lower volumes of oil, natural gas and NGL sold, the payment related to the litigation involving the early redemption of our 6.775% Senior Notes due 2019 and payments for terminations of transportation contracts. 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, certain impairments, gains or losses on sales of fixed assets, deferred income taxes and mark-to-market changes in our derivative instruments. See further discussion below under *Results of Operations*.

Debt issuances

The following table reflects the proceeds received from issuances of debt in 2018, 2017 and 2016. 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,					
	2018		2017		2016	
	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	$ 1,250	$ 1,236	$ 1,600	$ 1,585	$ 1,000	$ 975
Convertible senior notes	—	—	—	—	1,250	1,235
Term loans	—	—	—	—	1,500	1,476
Total	$ 1,250	$ 1,236	$ 1,600	$ 1,585	$ 3,750	$ 3,686

Divestitures of Proved and Unproved Properties

During 2018, we divested $2.231 billion of proved and unproved properties including $1.868 billion for all of our Utica Shale properties in Ohio. During 2017 and 2016, we divested certain non-core assets for approximately $1.249 billion and $1.406 billion, respectively. Proceeds from these transactions were used to repay debt and fund our development program. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31, 2018	2017	2016
		($ in millions)	
Oil and Natural Gas Expenditures:			
Drilling and completion costs	$ 1,958	$ 2,186	$ 1,295
Acquisitions of proved and unproved properties	135	101	552
Interest capitalized on unproved leasehold	153	184	236
Total oil and natural gas expenditures	2,246	2,471	2,083
Other Uses of Cash and Cash Equivalents:			
Cash paid to purchase debt	2,813	2,592	2,734
Payments on revolving credit facility borrowings, net	362	—	—
Extinguishment of other financing	122	—	—
Additions to other property and equipment	21	21	37
Cash paid for preferred stock dividends	92	183	—
Distributions to noncontrolling interest owners	6	8	10
Other	27	17	98
Total other uses of cash and cash equivalents	3,443	2,821	2,879
Total uses of cash and cash equivalents	$ 5,689	$ 5,292	$ 4,962

Drilling and Completion Costs

Our drilling and completion costs decreased in 2018 compared to 2017 primarily as a result of decreased completion activity. We completed 351 operated wells in 2018 compared to 401 in 2017.

Cash Paid to Purchase Debt

In 2018, we used $2.813 billion of cash to repurchase $2.701 billion principal amount of debt. In 2017, we used $2.592 billion of cash to repurchase $2.389 billion principal amount of debt. In 2016, we used $2.734 billion of cash to repurchase $2.884 billion principal amount of debt.

Extinguishment of Other Financing

In 2018, we repurchased previously conveyed overriding royalty interests (ORRIs) from the CHK Utica, L.L.C. investors and extinguished our obligation to convey future ORRIs to the investors for combined consideration of $199 million. The cash paid was bifurcated between extinguishment of the obligation and acquisition of the ORRI. See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the transaction.

Dividends

We paid dividends of $92 million on our preferred stock during 2018 and paid dividends of $183 million on our preferred stock in 2017, including $92 million of dividends in arrears that had been suspended throughout 2016. We did not pay dividends on our preferred stock in 2016. We eliminated common stock dividends in the 2015 third quarter and do not intend to resume paying cash dividends on our common stock in the foreseeable future.

Results of Operations

Oil, Natural Gas and NGL Production and Average Sales Prices

	2018								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	828	3.06	—	—	138	26	18.38
Haynesville	—	—	789	2.90	—	—	131	25	17.43
Eagle Ford	60	69.01	137	3.46	20	25.57	103	20	49.93
Powder River Basin	11	63.38	64	2.91	4	26.83	25	5	38.20
Mid-Continent	9	63.93	64	2.76	5	26.43	25	5	36.23
Retained assets[(a)]	80	67.67	1,882	3.01	29	25.88	422	81	27.98
Divested assets[(b)]	10	63.72	396	2.90	23	27.26	99	19	24.26
Total	90	67.25	2,278	2.99	52	26.50	521	100%	27.27

	2017								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	804	2.45	—	—	134	24	14.67
Haynesville	—	—	784	2.85	—	—	131	24	17.10
Eagle Ford	59	52.34	142	3.30	18	22.95	100	18	39.24
Powder River Basin	6	49.97	37	3.01	3	27.33	15	3	32.57
Mid-Continent	8	49.24	69	2.79	5	22.99	25	5	28.77
Retained assets[(a)]	73	51.78	1,836	2.71	26	23.37	405	74	23.07
Divested assets[(b)]	17	47.87	570	2.92	31	23.02	143	26	22.34
Total	90	51.03	2,406	2.76	57	23.18	548	100%	22.88

	2016								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	730	1.56	—	—	121	19	9.31
Haynesville	—	—	681	2.31	—	—	114	18	13.87
Eagle Ford	56	42.19	140	2.61	17	14.85	97	15	30.97
Powder River Basin	6	39.58	37	2.36	3	17.27	15	3	24.78
Mid-Continent	5	42.47	39	2.27	3	16.71	14	2	23.55
Retained assets[(a)]	67	41.98	1,627	2.00	23	15.26	361	57	17.76
Divested assets[(b)]	24	36.89	1,240	2.13	44	14.50	274	43	15.13
Total	91	40.65	2,867	2.05	67	14.76	635	100%	16.63

(a) Includes assets retained as of December 31, 2018.

(b) Divested assets include Barnett, Devonian and certain Mid-Continent assets in 2016, certain Haynesville assets in 2017 and Utica assets in Ohio in 2018.

Oil, Natural Gas and NGL Sales

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions)				
Oil	$ 2,201	32%	$ 1,668	23%	$ 1,351
Natural gas	2,486	3%	2,422	12%	2,155
NGL	502	4%	484	34%	360
Oil, natural gas and NGL sales	$ 5,189	13%	$ 4,574	18%	$ 3,866

2018 vs. 2017. The increase in the price received per boe in 2018 resulted in an $836 million increase in revenues, and decreased sales volumes resulted in a $221 million decrease in revenues, for a total net increase in revenues of $615 million.

2017 vs. 2016. The increase in the price received per boe in 2017 resulted in a $1.250 billion increase in revenues, and decreased sales volumes resulted in a $542 million decrease in revenues, for a total net increase in revenues of $708 million.

See Note 7 of the notes to our consolidated financial statements included in Item 8 of this report for a complete discussion of oil, natural gas and NGL sales.

Oil, Natural Gas and NGL Derivatives

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Oil derivatives – realized gains (losses)	$ (321)	$ 70	$ 97
Oil derivatives – unrealized gains (losses)	445	(134)	(318)
Total gains (losses) on oil derivatives	124	(64)	(221)
Natural gas derivatives – realized gains (losses)	7	(9)	151
Natural gas derivatives – unrealized gains (losses)	(154)	489	(500)
Total gains (losses) on natural gas derivatives	(147)	480	(349)
NGL derivatives – realized gains (losses)	(13)	(4)	(8)
NGL derivatives – unrealized gains (losses)	2	(1)	—
Total gains (losses) on NGL derivatives	(11)	(5)	(8)
Total gains (losses) on oil, natural gas and NGL derivatives	$ (34)	$ 411	$ (578)

See Note 13 of the notes to our consolidated financial statements included in Item 8 of this report for a complete discussion of our derivative activity.

Marketing Revenues and Expenses

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions)				
Marketing revenues	$ 5,076	13%	$ 4,511	(2)%	$ 4,584
Marketing expenses	5,158	12%	4,598	(4)%	4,778
Marketing gross margin	$ (82)	6%	$ (87)	55 %	$ (194)

2018 vs. 2017. Marketing revenues and expenses increased in 2018 primarily as a result of increased oil, natural gas and NGL prices received in our marketing operations. Gross margin was negatively impacted by downstream pipeline delivery commitments.

2017 vs. 2016. Marketing revenues and expenses decreased in 2017 primarily as a result of decreased oil, natural gas and NGL prices received in our marketing operations. Gross margin increased primarily as a result of the reversal of cumulative unrealized gains associated with the termination of a supply contract derivative in 2016 as well as the sale of a significant portion of our gathering and compression assets in 2016.

Oil, Natural Gas and NGL Production Expenses

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions)				
Oil, natural gas and NGL production expenses					
Marcellus	$ 34	21 %	$ 28	— %	$ 28
Haynesville	57	8 %	53	33 %	40
Eagle Ford	183	(3)%	188	27 %	148
Powder River Basin	49	63 %	30	36 %	22
Mid-Continent	102	(8)%	111	21 %	92
Retained Assets[(a)]	425	4 %	410	24 %	330
Divested Assets	49	(54)%	107	(67)%	325
Total	474	(8)%	517	(21)%	655
Ad valorem tax	65	44 %	45	(18)%	55
Total oil, natural gas and NGL production expenses	$ 539	(4)%	$ 562	(21)%	$ 710
	($ per boe)				
Oil, natural gas and NGL production expenses					
Marcellus	$ 0.68	17 %	$ 0.58	(8)%	$ 0.63
Haynesville	$ 1.20	9 %	$ 1.10	13 %	$ 0.97
Eagle Ford	$ 4.88	(5)%	$ 5.15	23 %	$ 4.18
Powder River Basin	$ 5.36	(3)%	$ 5.53	34 %	$ 4.14
Mid-Continent	$ 11.26	(7)%	$ 12.12	(30)%	$ 17.31
Retained Assets[(a)]	$ 2.76	(1)%	$ 2.78	11 %	$ 2.50
Divested Assets	$ 1.34	(34)%	$ 2.04	(37)%	$ 3.23
Total	$ 2.50	(3)%	$ 2.59	(8)%	$ 2.81
Ad valorem tax	$ 0.34	55 %	$ 0.22	(8)%	$ 0.24
Total oil, natural gas and NGL production expenses per boe	$ 2.84	1 %	$ 2.81	(8)%	$ 3.05

(a) Includes assets retained as of December 31, 2018.

2018 vs. 2017. The absolute increase for retained properties was the result of increased production volumes related to our retained assets primarily in the Powder River Basin. The total per unit increase was the result of increased ad valorem tax primarily due to higher prices received for our oil, natural gas and NGL production. Production expenses in 2018 included approximately $15 million associated with VPP production volumes.

2017 vs. 2016. The absolute and per unit decrease was the result of the sale of certain oil and natural gas properties in 2016, partially offset by increased workover costs in the Eagle Ford and increased water disposal costs in the Eagle Ford and Mid-Continent. Production expenses in 2017 and 2016 included approximately $19 million and $44 million, 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 remaining VPP agreement decrease and operating efficiencies generally improve.

Oil, Natural Gas, and NGL Gathering, Processing and Transportation Expenses

	Years Ended December 31,		
	2018	2017	2016
	($ in millions, except per unit)		
Oil, natural gas and NGL gathering, processing and transportation expenses	$ 1,398	$ 1,471	$ 1,855
Oil ($ per bbl)	$ 4.30	$ 3.94	$ 3.61
Natural gas ($ per mcf)	$ 1.32	$ 1.34	$ 1.47
NGL ($ per bbl)	$ 8.37	$ 7.88	$ 7.83
Total ($ per boe)	$ 7.35	$ 7.36	$ 7.98

2018 vs. 2017. The absolute and per unit decrease for oil and natural gas gathering, processing and transportation expenses was primarily due to lower gathering fees associated with restructured midstream contracts, lower volume commitments on downstream pipelines and certain 2017 and 2018 divestitures.

2017 vs. 2016. The absolute decrease was primarily due to lower volumes. The per unit decrease was due to contract improvements and asset sales.

Production Taxes

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions, except per unit)				
Production taxes	$ 124	39%	$ 89	20%	$ 74
Production taxes per boe	$ 0.65	48%	$ 0.44	38%	$ 0.32

The absolute and per unit increase in production taxes for each year was primarily due to higher prices received for our oil, natural gas and NGL production, offset by lower production volumes.

General and Administrative Expenses

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions, except per unit)				
Gross overhead	$ 714	(10)%	$ 791	(12)%	$ 900
Allocated to production expenses	(141)	(20)%	(177)	(15)%	(209)
Allocated to marketing	(20)	(31)%	(29)	(47)%	(55)
Capitalized general and administrative expenses	(119)	(13)%	(137)	(8)%	(149)
Reimbursed from third parties	(154)	(17)%	(186)	(25)%	(247)
General and administrative expenses, net	$ 280	7 %	$ 262	9 %	$ 240
General and administrative expenses, net per boe	$ 1.47	12 %	$ 1.31	27 %	$ 1.03

2018 vs. 2017. Gross overhead decreased primarily due to our reduction in workforce. The absolute and per unit net expense increase was primarily due to less overhead allocated to production expenses, marketing expenses and capitalized general and administrative costs, as well as lower producing overhead reimbursements from third party working interest owners, due to certain divestitures in 2017 and 2018.

2017 vs. 2016. Gross overhead decreased primarily due to lower compensation costs and lower legal fees. The absolute and per unit net expense increase was primarily due to less overhead allocated to production expenses, marketing expenses and capitalized general and administrative costs, as well as less overhead billed to third party working interest owners, due to certain divestitures in 2016 and 2017.

Restructuring and Other Termination Costs. On January 30, 2018, we underwent a reduction in workforce impacting approximately 13% of employees across all functions, primarily on our Oklahoma City campus. In connection with the reduction, we incurred a total charge of approximately $38 million in 2018 for one-time termination benefits. The charge consisted of $33 million in salary and severance expense and $5 million in other termination benefits. In 2016, we recognized $6 million of charges related to a reduction of workforce in connection with the restructuring of our compressor manufacturing subsidiary and the reductions of workforce resulting from the conveyance of our interests in the Barnett Shale and Devonian Shale operating areas. See Note 19 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our restructuring and termination costs.

Provision for Legal Contingencies, Net

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Provision for legal contingencies, net	$ 26	$ (38)	$ 123

The 2018 and 2016 amounts consist of accruals for loss contingencies primarily related to royalty claims. The 2017 amount consists of the recovery of a legal settlement, partially offset by accruals for loss contingencies primarily related to royalty claims. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of royalty claims.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions, except per unit)				
Oil, natural gas and NGL depreciation, depletion and amortization	$ 1,145	15%	$ 995	(10)%	$ 1,107
Oil, natural gas and NGL depreciation, depletion and amortization per boe	$ 6.02	21%	$ 4.98	5 %	$ 4.76

2018 vs. 2017. The absolute and per unit increase in 2018 is primarily the result of a higher depletion rate per boe. The depletion rate per boe is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented. The increase in depletion rate per boe primarily reflects a downward revision in proved reserve estimates in the fourth quarter of 2017 due to an updated development plan in the Eagle Ford aligning up-spacing, our activity schedule and well performance.

2017 vs. 2016. The absolute decrease was primarily the result of the sale of Barnett and certain Mid-Continent assets in 2016 and the sale of certain Haynesville assets in 2017.

Loss on Sale of Oil and Natural Gas Properties

In 2018, we sold all of our net acres in the Utica Shale operating area located in Ohio along with related property and equipment (collectively, the “Designated Properties”) for net proceeds of $1.868 billion to Encino. The sale of our Designated Properties to Encino involved a significant change in proved reserves under SEC rules for full cost companies and significantly altered the relationship between costs and proved reserves and therefore resulted in the recognition of loss of approximately $578 million. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the transaction.

Impairments

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions)				
Impairments	$ 53	960%	$ 5	(100)%	$ 3,025

In 2018, we recorded a $45 million impairment related to 890 compressors and $8 million for other property and equipment for the difference between the fair value and carrying value. In 2016, we recognized an impairment in the carrying value of our oil and natural gas properties of $2.564 billion and impairments totaling $426 million related to other fixed assets sold in our Barnett Shale and Devonian Shale divestitures. See Note 17 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our impairments.

Other Operating Expense

	Years Ended December 31,				
	2018	change	2017	change	2016
		($ in millions)			
Other operating expense	$ 10	(98)%	$ 413	13%	$ 365

The 2017 and 2016 amounts consist of discrete costs incurred to terminate various gathering and transportation agreements, including those associated with oil and natural gas asset divestitures. See Note 18 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our other operating expense.

Interest Expense

	Years Ended December 31,		
	2018	2017	2016
		($ in millions)	
Interest expense on senior notes	$ 591	$ 551	$ 588
Interest expense on term loan	86	127	46
Amortization of loan discount, issuance costs and other	24	40	33
Amortization of premium	(88)	(138)	(165)
Interest expense on revolving credit facility	37	39	35
Realized gains on interest rate derivatives	(3)	(3)	(11)
Unrealized losses on interest rate derivatives	2	4	21
Capitalized interest	(162)	(194)	(251)
Total interest expense	$ 487	$ 426	$ 296
Interest expense per boe[(a)]	$ 2.55	$ 2.11	$ 1.18
Average senior notes borrowings	$ 8,160	$ 7,714	$ 8,749
Average credit facilities borrowings	$ 505	$ 443	$ 195
Average term loan borrowings	$ 911	$ 1,446	$ 537

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

The decrease in capitalized interest is a result of lower average balances of unproved oil and natural gas properties, the primary asset on which interest is capitalized. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our debt refinancing.

Gains (Losses) on Investments. In 2018, FTS International, Inc. (NYSE: FTSI) completed an initial public offering. Due to the offering, the ownership percentage of our equity method investment in FTSI decreased from approximately 29% to 24% and resulted in a gain of $78 million. In addition, we sold approximately 4.3 million shares of FTSI in the offering for net proceeds of approximately $74 million and recognized a gain of $61 million decreasing our ownership percentage to approximately 20%. We continue to hold approximately 22.0 million shares in the publicly traded company. In 2016, we recognized an other-than-temporary impairment of our Sundrop Fuels Inc. (Sundrop) investment of $119 million. See Note 16 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our investments.

Gains (Losses) on Purchases or Exchanges of Debt. In 2018, we used the net proceeds from the issuance of our 2024 and 2026 senior notes, together with cash on hand and borrowings under the Chesapeake revolving credit facility, to repay in full $1.233 billion of borrowings under our secured term loan due 2021 for $1.285 billion, which included a $52 million make-whole premium. We recorded a loss of approximately $65 million associated with the repayment of the term loan, including the make-whole premium and the write-off of $13 million of associated deferred charges. Also in 2018, we used the proceeds from the sale of our Utica assets in Ohio to redeem all of the $1.416 billion aggregate principal amount outstanding of our 8.00% Senior Secured Second Lien Notes due 2022 which included a $60 million call premium. We recorded a gain of approximately $331 million associated with the redemption, including the realization of the remaining $391 million difference in principal and book value due to troubled debt restructuring accounting in 2015, offset by the make-whole premium of $60 million. Additionally, we recorded a loss of $3 million associated with certain deferred charges related to the Chesapeake revolving credit facility prior to its amendment and restatement.

In 2017, we retired $2.389 billion principal amount of our outstanding senior notes, senior secured second lien notes and contingent convertible notes through purchases in the open market, tender offers, redemptions or repayment upon maturity for $2.592 billion, which included the maturity of our 6.25% Euro-denominated Senior Notes due 2017 and the corresponding cross currency swap. We recorded an aggregate gain of approximately $233 million associated with the repurchases and tender offers.

In 2016, we used the proceeds from our term loan facility, convertible notes issuance and senior notes issuance, together with cash on hand, to purchase and retire $2.884 billion principal amount of our outstanding senior notes and contingent convertible senior notes through purchases in the open market, tender offers or repayment upon maturity for $2.734 billion. Additionally, we privately negotiated an exchange of approximately $577 million principal amount of our outstanding senior notes and contingent convertible senior notes for 109,351,707 common shares. We recorded an aggregate gain of approximately $236 million associated with the repurchases and exchanges.

Other Income. In 2018, we extinguished our obligation to convey future ORRIs to the CHK Utica L.L.C. investors and recognized a $61 million gain included in other income on our consolidated statement of operations. See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of this transaction.

Income Tax Expense (Benefit). We recorded an income tax benefit of $10 million in 2018, income tax expense of $2 million in 2017 and an income tax benefit of $190 million in 2016. Our effective tax rate can fluctuate as a result of various items, including the impact of state income taxes, permanent differences, tax law changes and adjustments to the valuation allowance. See Note 8 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of income tax expense (benefit).

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States require us to make estimates and assumptions. The accounting estimates and assumptions we consider to be most significant to our financial statements are discussed below. Our management has discussed each critical accounting estimate with the Audit Committee of our Board of Directors.

Oil and Natural Gas Properties. We follow the full cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized.

Under the full cost method, capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas 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.

We review the carrying value of our oil and natural gas properties under the full cost method of accounting prescribed by the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test.

Two primary factors impacting this test are reserve estimates and the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2018. Downward revisions to estimates of oil and natural gas reserves and/or unfavorable 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 *Oil and Natural Gas 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.

Oil and Natural Gas Reserves. Estimates of oil and natural gas reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in oil, natural gas or NGL prices could result in actual results differing significantly from our estimates. See *Supplemental Disclosures About Oil, Natural Gas, and NGL Producing Activities* included in Item 8 of this report for further information.

Derivatives. We use commodity price and financial risk management instruments to mitigate a portion of our exposure to price fluctuations in oil, natural gas and NGL prices. Results of commodity derivative contracts are reflected in oil, natural gas and NGL revenues and results of interest rate derivative contracts are reflected in interest expense.

Due to the volatility of oil, natural gas and NGL prices and, to a lesser extent, interest rates and foreign exchange rates, our financial condition and results of operations may be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2018 and 2017, the fair values of our derivatives were net assets of $282 million and net liabilities of $35 million, respectively.

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. This 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.

Income Taxes. The amount of income taxes recorded requires interpretations and application of complex rules and regulations pertaining to federal, state and local taxing jurisdictions. Income taxes are accounted for using the asset and liability method as required by GAAP. We recognize deferred tax assets and liabilities for temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets for NOL and tax credit carryforwards have also been recognized. We routinely assess the realizability of our deferred tax assets and reduce such assets by a valuation allowance if it is more likely than not that all or some portion of the deferred tax assets will not be realized. In assessing the need for additional valuation allowances or adjustments to existing valuation allowances, we consider the weight of all available evidence, both positive and negative, concerning the realization of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years;
- reversal of existing deferred tax liabilities against deferred tax assets and 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.

Our judgments and assumptions in estimating future taxable income include such factors as future operating conditions and commodity prices when determining if deferred tax assets are not more likely than not to be realized. As of December 31, 2018 and 2017, we had deferred tax assets totaling $3.252 billion and $2.826 billion upon which we had a valuation allowance of $2.433 billion and $2.674 billion, respectively.

We also routinely assess potential uncertain tax positions and, if required, establish accruals for such positions. Accounting guidance for recognizing and measuring uncertain tax positions requires that a more likely than not threshold condition be met on a tax position, based solely on its technical merits of being sustained, before any benefit of the uncertain tax position can be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. If a tax position does not meet or exceed the more likely than not threshold then no benefit can be recorded. We accrue any applicable interest related to uncertain tax positions as a component of interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expense. Additional information about uncertain tax positions appears in Note 8 of the notes to our consolidated financial statements included in Item 8 of this report.

Disclosures About Effects of Transactions with Related Parties

Our equity method investees are considered related parties. See Note 9 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of transactions with our equity method investees.

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

Oil, Natural Gas and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL. To mitigate a portion of our exposure to adverse price changes, we have entered into various derivative instruments. Our oil, natural gas and NGL derivative activities, when combined with our sales of oil, natural gas and NGL, allow us to predict with greater certainty the revenue we will receive. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for protecting short-term cash flow and attempting to mitigate exposure to adverse oil, natural gas and NGL price changes is to hedge into strengthening oil, natural gas and NGL futures markets when prices reach levels that management believes are 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, oil and natural gas storage inventory levels, industry decline rates for base production and weather trends. Executive management is involved in all risk management activities and the Board of Directors reviews our derivative program at its quarterly board meetings. We believe we have sufficient internal controls to prevent unauthorized trading.

We use derivative instruments to achieve our risk management objectives, including swaps, collars and options. All of these are described in more detail below. We typically use swaps and collars for a large portion of the oil and natural gas price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility.

We determine the notional 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 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 volumes in excess of our share of forecasted production, and if production estimates were lowered for future periods and derivative instruments are already executed for some volume above the new production forecasts, the positions would be 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 commodity derivative instruments are net settled based on the difference between the fixed price as stated in the contract and the floating-price, resulting in a net amount due to or from the counterparty.

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 this 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 review when deciding to enter into the original derivative position. Gains or losses related to closed positions will be recognized in the month 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. This 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 commodity hedging arrangements that require counterparties to post collateral if their obligations to us 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 13 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, 2018, our oil, natural gas and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*: We receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. In exchange for higher fixed prices on certain of our swap trades, we may sell call options and call swaptions.
- *Options*: We sell, and occasionally buy, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the counterparty the excess on sold call options, and we receive the excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
- *Call Swaptions*: We sell call swaptions to counterparties in exchange for a premium that allow the counterparty, on a specific date, to extend an existing fixed-price swap for a certain period of time
- *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, we receive the fixed price and pay 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 the sale by us of an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option strike price.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. We receive the fixed price differential and pay the floating market price differential to the counterparty for the hedged commodity.

As of December 31, 2018, we had the following open oil and natural gas derivative instruments:

		Weighted Average Price				Fair Value
	Volume	Fixed	Call	Put	Differential	Asset (Liability)
	(mmbbl)	($ per bbl)				($ in millions)
Oil:						
Swaps:						
Short-term	10	$ 58.97	$ —	$ —	$ —	$ 117
Long-term	2	$ 68.14	$ —	$ —	$ —	40
Collars:						
Short-term	6	$ —	$ 67.75	$ 58.00	$ —	68
Long-term	2	$ —	$ 83.25	$ 65.00	$ —	30
Basis Protection Swaps:						
Short-term	7	$ —	$ —	$ —	$ 6.01	5
Total Oil						260
	(bcf)	($ per mcf)				
Natural Gas:						
Swaps:						
Short-term	447	$ 2.87	$ —	$ —	$ —	11
Long-term	176	$ 2.75	$ —	$ —	$ —	15
Three-Way Collars:						
Short-term	88	$ —	$ 3.10	$ 2.50/2.80	$ —	1
Collars:						
Short-term	55	$ —	$ 3.02	$ 2.75	$ —	(3)
Call Options (sold):						
Short-term	22	$ —	$ 12.00	$ —	$ —	—
Long-term	22	$ —	$ 12.00	$ —	$ —	—
Call Swaptions:						
Long-term	106	$ 2.77	$ —	$ —	$ —	(9)
Basis Protection Swaps:						
Short-term	50	$ —	$ —	$ —	$ (0.56)	—
Total Natural Gas						15
Total Commodities						275
Contingent Consideration:						
Utica Divestiture:						
Short-term	—	$ —	$ —	$ —	$ —	7
Total Derivative Asset						$ 282

In addition to the open derivative positions disclosed above, as of December 31, 2018, we had $56 million of net derivative losses related to settled contracts for future periods that will be recorded within oil, natural gas and NGL revenues as realized gains (losses) on derivatives once they are transferred from either accumulated other comprehensive income or unrealized gains (losses) on derivatives in the month of related production, based on the terms specified in the original contract as noted below:

	December 31, 2018
	($ in millions)
Short-term	$ (23)
Long-term	(33)
Total	$ (56)

The table below reconciles the changes in fair value of our oil and natural gas derivatives during 2018. Of the $282 million fair value asset as of December 31, 2018, a $206 million asset relates to contracts maturing in the next 12 months and a $76 million asset relates to contracts maturing after 12 months. All open derivative instruments as of December 31, 2018 are expected to mature by December 31, 2020.

	December 31, 2018
	($ in millions)
Fair value of contracts outstanding, as of January 1, 2018	$ (35)
Change in fair value of contracts	644
Contracts realized or otherwise settled	(327)
Fair value of contracts outstanding, as of December 31, 2018	$ 282

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates, using the earliest demand repurchase date for contingent convertible senior notes.

	Years of Maturity						
	2019	2020	2021	2022	2023	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate	$ 1	$ 664	$ 815	$ 451	$ 338	$ 5,100	$ 7,369
Average interest rate	2.25%	6.71%	5.88%	4.88%	5.75%	7.18%	6.79%
Debt – variable rate	$ 380	$ —	$ —	$ —	$ 419	$ —	$ 799
Average interest rate	5.68%	—%	—%	—%	3.89%	—%	4.74%

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

As of December 31, 2018, we had $5 million of net gains related to settled interest rate derivative contracts that will be recorded within interest expense as realized gains or losses once they are transferred from our senior note liability or within interest expense as unrealized gains or losses over the remaining six-year term of our related senior notes.

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

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

INDEX TO FINANCIAL STATEMENTS
CHESAPEAKE ENERGY CORPORATION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of the management of Chesapeake Energy Corporation to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management utilized the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control-Integrated Framework* (2013) in conducting the required assessment of effectiveness of the Company's internal control over financial reporting.

Management has performed an assessment of the effectiveness of the Company's internal control over financial reporting and has determined the Company's internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of the Company's internal control over financial reporting, as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report, which appears herein.

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

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

February 27, 2019

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Chesapeake Energy Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Chesapeake Energy Corporation and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income (loss), cash flows and stockholders' equity for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
February 27, 2019

We have served as the Company's auditor since 1992.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2018	2017
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $2 attributable to our VIE)	$ 4	$ 5
Accounts receivable, net	1,247	1,322
Short-term derivative assets	209	27
Other current assets	138	171
Total Current Assets	1,598	1,525
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full cost accounting:		
Proved oil and natural gas properties ($488 and $488 attributable to our VIE)	69,642	68,858
Unproved properties	2,337	3,484
Other property and equipment	1,721	1,986
Total Property and Equipment, at Cost	73,700	74,328
Less: accumulated depreciation, depletion and amortization (($465) and ($461) attributable to our VIE)	(64,685)	(63,664)
Property and equipment held for sale, net	15	16
Total Property and Equipment, Net	9,030	10,680
LONG-TERM ASSETS:		
Long-term derivative assets	76	—
Other long-term assets	243	220
TOTAL ASSETS	$ 10,947	$ 12,425

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

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

	December 31, 2018	December 31, 2017
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 763	$ 654
Current maturities of long-term debt, net	381	52
Accrued interest	141	137
Short-term derivative liabilities	3	58
Other current liabilities ($2 and $3 attributable to our VIE)	1,540	1,455
Total Current Liabilities	2,828	2,356
LONG-TERM LIABILITIES:		
Long-term debt, net	7,341	9,921
Long-term derivative liabilities	—	4
Asset retirement obligations, net of current portion	155	162
Other long-term liabilities	156	354
Total Long-Term Liabilities	7,652	10,441
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 5,603,458 shares outstanding	1,671	1,671
Common stock, $0.01 par value, 2,000,000,000 shares authorized: 913,715,512 and 908,732,809 shares issued	9	9
Additional paid-in capital	14,378	14,437
Accumulated deficit	(15,660)	(16,525)
Accumulated other comprehensive loss	(23)	(57)
Less: treasury stock, at cost; 3,246,553 and 2,240,394 common shares	(31)	(31)
Total Chesapeake Stockholders' Equity (Deficit)	344	(496)
Noncontrolling interests	123	124
Total Equity (Deficit)	467	(372)
TOTAL LIABILITIES AND EQUITY	$ 10,947	$ 12,425

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2018	2017	2016
	($ in millions except per share data)		
REVENUES:			
Oil, natural gas and NGL	$ 5,155	$ 4,985	$ 3,288
Marketing	5,076	4,511	4,584
Total Revenues	10,231	9,496	7,872
OPERATING EXPENSES:			
Oil, natural gas and NGL production	539	562	710
Oil, natural gas and NGL gathering, processing and transportation	1,398	1,471	1,855
Production taxes	124	89	74
Marketing	5,158	4,598	4,778
General and administrative	280	262	240
Restructuring and other termination costs	38	—	6
Provision for legal contingencies, net	26	(38)	123
Depreciation, depletion and amortization	1,145	995	1,107
Loss on sale of oil and natural gas properties	578	—	—
Impairments	53	5	3,025
Other operating expenses	10	413	365
Total Operating Expenses	9,349	8,357	12,283
INCOME (LOSS) FROM OPERATIONS	882	1,139	(4,411)
OTHER INCOME (EXPENSE):			
Interest expense	(487)	(426)	(296)
Gains (losses) on investments	139	—	(137)
Gains on purchases or exchanges of debt	263	233	236
Other income	70	9	19
Total Other Expense	(15)	(184)	(178)
INCOME (LOSS) BEFORE INCOME TAXES	867	955	(4,589)
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	—	(9)	(19)
Deferred income taxes	(10)	11	(171)
Total Income Tax Expense (Benefit)	(10)	2	(190)
NET INCOME (LOSS)	877	953	(4,399)
Net (income) loss attributable to noncontrolling interests	(4)	(4)	9
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	873	949	(4,390)
Preferred stock dividends	(92)	(85)	(97)
Loss on exchange of preferred stock	—	(41)	(428)
Earnings allocated to participating securities	(6)	(10)	—
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 775	$ 813	$ (4,915)
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ 0.85	$ 0.90	$ (6.43)
Diluted	$ 0.85	$ 0.90	$ (6.43)
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	909	906	764
Diluted	909	906	764

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

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

	Years Ended December 31,		
	2018	2017	2016
		($ in millions)	
NET INCOME (LOSS)	$ 877	$ 953	$ (4,399)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Unrealized gains (losses) on derivative instruments, net of income tax benefit of $0, $0, and ($14)	—	5	(13)
Reclassification of losses on settled derivative instruments, net of income tax expense of $0, $0 and $18	34	34	16
Other Comprehensive Income	34	39	3
COMPREHENSIVE INCOME (LOSS)	911	992	(4,396)
COMPREHENSIVE (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(4)	(4)	9
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 907	$ 988	$ (4,387)

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ 877	$ 953	$ (4,399)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	1,145	995	1,107
Deferred income tax expense (benefit)	(10)	11	(171)
Derivative (gains) losses, net	26	(409)	739
Cash receipts (payments) on derivative settlements, net	(345)	(18)	448
Stock-based compensation	32	49	52
Loss on sale of oil and gas properties	578	—	—
Impairments	53	5	3,025
(Gains) losses on investments	(139)	—	137
Gains on purchases or exchanges of debt	(263)	(235)	(236)
Other	(108)	(135)	(145)
(Increase) decrease in accounts receivable and other assets	16	(163)	(4)
(Decrease) increase in accounts payable, accrued liabilities and other	138	(308)	(757)
Net Cash Provided By (Used In) Operating Activities	2,000	745	(204)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and completion costs	(1,958)	(2,186)	(1,295)
Acquisitions of proved and unproved properties	(288)	(285)	(788)
Proceeds from divestitures of proved and unproved properties	2,231	1,249	1,406
Additions to other property and equipment	(21)	(21)	(37)
Proceeds from sales of other property and equipment	147	55	131
Proceeds from sales of investments	74	—	—
Other	—	—	(77)
Net Cash Provided By (Used In) Investing Activities	185	(1,188)	(660)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from revolving credit facility borrowings	11,697	7,771	5,146
Payments on revolving credit facility borrowings	(12,059)	(6,990)	(5,146)
Proceeds from issuance of senior notes, net	1,236	1,585	2,210
Proceeds from issuance of term loan, net	—	—	1,476
Cash paid to purchase debt	(2,813)	(2,592)	(2,734)
Extinguishment of other financing	(122)	—	—
Cash paid for preferred stock dividends	(92)	(183)	—
Distributions to noncontrolling interest owners	(6)	(8)	(10)
Other	(27)	(17)	(21)
Net Cash Provided By (Used In) Financing Activities	(2,186)	(434)	921
Net increase (decrease) in cash and cash equivalents	(1)	(877)	57
Cash and cash equivalents, beginning of period	5	882	825
Cash and cash equivalents, end of period	$ 4	$ 5	$ 882

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

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

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

	Years Ended December 31,		
	2018	2017	2016
		($ in millions)	
SUPPLEMENTAL CASH FLOW INFORMATION:			
Interest paid, net of capitalized interest	$ 518	$ 492	$ 344
Income taxes paid, net of refunds received	$ (3)	$ (16)	$ (27)
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Change in accrued drilling and completion costs	$ 174	$ 14	$ (23)
Change in accrued acquisitions of proved and unproved properties	$ 7	$ 9	$ (13)
Change in divested proved and unproved properties	$ (21)	$ (57)	$ 52
Acquisition of other property and equipment including assets under capital lease	$ 27	$ —	$ —
Debt exchanged for common stock	$ —	$ —	$ 471

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 1,671	$ 1,771	$ 3,062
Exchange/conversions of 0, 236,048 and 1,412,009 shares of preferred stock for common stock	—	(100)	(1,291)
Balance, end of period	1,671	1,671	1,771
COMMON STOCK:			
Balance, beginning of period	9	9	7
Exchange of senior notes, contingent convertible notes and preferred stock	—	—	1
Conversion of preferred stock	—	—	1
Balance, end of period	9	9	9
ADDITIONAL PAID-IN CAPITAL:			
Balance, beginning of period	14,437	14,486	12,403
Stock-based compensation	33	54	64
Exchange of contingent convertible notes for 0, 0 and 55,427,782 shares of common stock	—	—	241
Exchange of senior notes for 0, 0 and 53,923,925 shares of common stock	—	—	229
Exchange/conversion of preferred stock for 0, 9,965,835, and 120,186,195 shares of common stock	—	100	1,290
Issuance of 5.5% convertible senior notes due 2026	—	—	445
Tax effect on the issuance of 5.5% convertible senior notes due 2026	—	—	(165)
Equity component of contingent convertible notes repurchased, net of tax	—	(20)	(16)
Dividends on preferred stock	(92)	(183)	—
Issuance costs	—	—	(5)
Balance, end of period	14,378	14,437	14,486
RETAINED EARNINGS (ACCUMULATED DEFICIT):			
Balance, beginning of period	(16,525)	(17,474)	(13,084)
Net income (loss) attributable to Chesapeake	873	949	(4,390)
Cumulative effect of change in accounting principle	(8)	—	—
Balance, end of period	(15,660)	(16,525)	(17,474)
ACCUMULATED OTHER COMPREHENSIVE LOSS:			
Balance, beginning of period	(57)	(96)	(99)
Hedging activity	34	39	3
Balance, end of period	(23)	(57)	(96)

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY - (Continued)

	Years Ended December 31,		
	2018	2017	2016
		($ in millions)	
TREASURY STOCK – COMMON:			
Balance, beginning of period	(31)	(27)	(33)
Purchase of 1,510,022, 1,206,419, and 37,871 shares for company benefit plans	(4)	(7)	—
Release of 503,863, 186,529 and 255,091 shares from company benefit plans	4	3	6
Balance, end of period	(31)	(31)	(27)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY (DEFICIT)	344	(496)	(1,331)
NONCONTROLLING INTERESTS:			
Balance, beginning of period	124	128	141
Net income (loss) attributable to noncontrolling interests	4	4	(9)
Distributions to noncontrolling interest owners	(5)	(8)	(4)
Balance, end of period	123	124	128
TOTAL EQUITY (DEFICIT)	$ 467	$ (372)	$ (1,203)

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

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation ("Chesapeake", “we,” “our”, “us” or the "Company") is an oil and natural gas exploration and production company engaged in the acquisition, exploration and development of properties for the production of oil, natural gas and natural gas liquids (NGL) from underground reservoirs. Our operations are located onshore in the United States.

Basis of Presentation

The accompanying consolidated financial statements of Chesapeake were prepared in accordance with GAAP and include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake has a controlling financial interest. Intercompany accounts and balances have been eliminated.

Accounting Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the related disclosures in the financial statements. Management evaluates its estimates and related assumptions regularly, including those related to the impairment of oil and natural gas properties, oil and natural gas reserves, derivatives, income taxes, unevaluated properties not subject to evaluation, impairment of other property and equipment, environmental remediation costs, asset retirement obligations, litigation and regulatory proceedings and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ significantly from these estimates.

Consolidation

We consolidate entities in which we have a controlling financial interest. We consolidate subsidiaries in which we hold, directly or indirectly, more than 50% of the voting rights and variable interest entities (VIEs) in which we are the primary beneficiary. We consolidate a VIE when we are the primary beneficiary, which is the party that has both (i) the power to direct the activities that most significantly impact the VIE’s economic performance and (ii) through its interests in the VIE, the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether we own a variable interest in a VIE, we perform a qualitative analysis of the entity’s design, organizational structure, primary decision makers and relevant agreements. We continually monitor our consolidated VIE to determine if any events have occurred that could cause the primary beneficiary to change. See Note 10 for further discussion of our VIE. We use the equity method of accounting to record our net interests where we have the ability to exercise significant influence through our investment but lack a controlling financial interest. Under the equity method, our share of net income (loss) is included in our consolidated statements of operations according to our equity ownership or according to the terms of the applicable governing instrument. Undivided interests in oil and natural gas properties are consolidated on a proportionate basis.

Segments

Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker for the purpose of allocating an enterprise’s resources and assessing its operating performance. We have concluded that we have only one reportable operating segment, which is exploration and production because our marketing activities are ancillary to our operations.

Noncontrolling Interests

Noncontrolling interests represent third-party equity ownership in certain of our consolidated subsidiaries and are presented as a component of equity. See Note 10 for further discussion of noncontrolling interests.

Cash and Cash Equivalents

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

Accounts Receivable

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL and from exploration and production companies that own interests in properties we operate. This industry concentration could affect our overall exposure to credit risk, either positively or negatively, because our purchasers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of all our counterparties and we generally require letters of credit or parent guarantees for receivables from parties deemed to have sub-standard credit, unless the credit risk can otherwise be mitigated. We utilize an allowance method in accounting for bad debt based on historical trends in addition to specifically identifying receivables that we believe may be uncollectible. See Note 7 for further discussion of our accounts receivable.

Oil and Natural Gas Properties

We follow the full cost method of accounting under which all costs associated with oil and natural gas property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with these activities and do not capitalize any costs related to production, general corporate overhead or similar activities. Capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. Estimates of our proved reserves as of December 31, 2018 were prepared by an independent engineering firm and our internal staff.

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

The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unproved properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties and otherwise if impairment has occurred.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2018 and the year in which the associated costs were incurred:

	Year of Acquisition				
	2018	2017	2016	Prior	Total
			($ in millions)		
Leasehold cost	$ 24	$ 31	$ 40	$ 1,577	$ 1,672
Exploration cost	122	—	2	—	124
Capitalized interest	125	84	63	269	541
Total	$ 271	$ 115	$ 105	$ 1,846	$ 2,337

We also review, on a quarterly basis, the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects.

Other Property and Equipment

Other property and equipment consists primarily of buildings and improvements, land, vehicles, computers, natural gas compressors under capital lease and office equipment. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. Other property and equipment costs, excluding land, are depreciated on a straight-line basis and recorded within depreciation and amortization of other assets in the consolidated statement of operations. Natural gas compressors under capital lease are depreciated over the shorter of their estimated useful lives or the term of the related lease.

Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including any disposal value, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets and discounted cash flow.

Capitalized Interest

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

Accounts Payable

Included in accounts payable as of December 31, 2018 and 2017 are liabilities of approximately $104 million and $92 million, respectively, representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts.

Debt Issuance Costs

Included in other long-term assets are costs associated with the issuance and amendments of the Chesapeake revolving credit facility. The remaining unamortized issuance costs as of December 31, 2018 and 2017, totaled $30 million and $22 million, respectively, and are being amortized over the life of the Chesapeake revolving credit facility using the straight-line method. Included in debt are costs associated with the issuance of our senior notes. The remaining unamortized issuance costs as of December 31, 2018 and 2017, totaled $53 million and $63 million, respectively, and are being amortized over the life of the senior notes using the effective interest method.

Litigation Contingencies

We are subject to litigation and regulatory proceedings, claims and liabilities that arise in the ordinary course of business. We accrue losses associated with litigation and regulatory claims when such losses are probable and reasonably estimable. If we determine that a loss is probable and cannot estimate a specific amount for that loss but can estimate a range of loss, our best estimate within the range is accrued. Estimates are adjusted as additional information becomes available or circumstances change. Legal defense costs associated with loss contingencies are expensed in the period incurred.

Environmental Remediation Costs

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

Asset Retirement Obligations

We recognize liabilities for obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which an oil or natural gas well is acquired or drilled. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our oil and natural gas properties. See Note 21 for further discussion of asset retirement obligations.

Revenue Recognition

Revenue from the sale of oil, natural gas and NGL is recognized upon the transfer of control of the products, which is typically when the products are delivered to customers. Prior to the adoption of *Revenue from Contracts with Customers* (Topic 606) on January 1, 2018, revenue from the sale of oil, natural gas and NGL was recognized when title passed to customers. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration we expect to receive in exchange for those products.

Revenue from contracts with customers includes the sale of our oil, natural gas and NGL production (recorded as oil, natural gas and NGL revenues in the consolidated statements of operations) as well as the sale of certain of our joint interest holders' production which we purchase under joint operating arrangements (recorded in marketing revenues in the consolidated statements of operations). In connection with the marketing of these products, we obtain control of the oil, natural gas and NGL we purchase from other interest owners at defined delivery points and deliver the product to third parties, at which time revenues are recorded.

Payment terms and conditions vary by contract type, although terms generally include a requirement of payment within 30 days. There are no significant judgments that significantly affect the amount or timing of revenue from contracts with customers.

We also earn revenue from other sources, including from a variety of derivative and hedging activities to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility, (recorded within oil, natural gas and NGL revenues in the consolidated statements of operations) as well as a variety of oil, natural gas and NGL purchase and sale contracts with third parties for various commercial purposes, including credit risk mitigation and satisfaction of our pipeline delivery commitments (recorded within marketing revenues in the consolidated statements of operations).

In circumstances where we act as an agent rather than a principal, our results of operations related to oil, natural gas and NGL marketing activities are presented on a net basis.

Fair Value Measurements

Certain financial instruments are reported at fair value on our consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (i.e. an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest priority.

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

The carrying values of financial instruments comprising cash and cash equivalents, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments.

Derivatives

Derivative instruments are recorded at fair value, and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are followed. As of December 31, 2018, none of our open derivative instruments were designated as cash flow hedges.

Derivative instruments reflected as current in the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the respective balance sheet dates. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows. All of our derivative instruments are subject to master netting arrangements by contract type which provide for the offsetting of asset and liability positions within each contract type, as well as related cash collateral if applicable, by counterparty. Therefore, we net the value of our derivative instruments by contract type with the same counterparty in the accompanying consolidated balance sheets.

We have established the fair value of our derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. Derivative transactions are subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. See Note 13 for further discussion of our derivative instruments.

Share-Based Compensation

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

To the extent compensation expense relates to employees directly involved in the acquisition of oil and natural gas leasehold and exploration and development activities, these amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expenses, oil, natural gas and NGL production expenses, or marketing, gathering and compression expenses, based on the employees involved in those activities. See Note 11 for further discussion of share-based compensation.

Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) issued Topic 606 superseding virtually all existing revenue recognition guidance. We adopted this new standard in the first quarter of 2018 using the modified retrospective approach. See Note 7 for further details regarding our adoption of Topic 606.

In February 2018, the FASB issued Accounting Standards Update (ASU) 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. The new standard allows for stranded tax effects resulting from the tax reform legislation commonly known as the Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 (the “Tax Act”), previously recognized in accumulated other comprehensive income to be reclassified to retained earnings. For public business entities, the amendments are effective for annual periods, including interim periods within the annual periods, beginning after December 15, 2018. This standard is effective for us beginning on January 1, 2019, and we will elect not to reclassify the income tax effects of the Tax Act from accumulated other comprehensive income to retained earnings.

In August 2017, the FASB issued ASU 2017-12*, Derivatives and Hedging (Topic 815),* which makes significant changes to the current hedge accounting guidance. The new standard eliminates the requirement to separately measure and report hedge ineffectiveness and generally requires the entire change in the fair value of a hedging instrument to be presented in the same income statement line as the hedged item. The new standard also eases certain documentation and assessment requirements and modifies the accounting for components excluded from the assessment of hedge effectiveness. The new standard update is effective for annual and interim periods beginning after December 15, 2018, including interim periods within those annual periods. Early adoption is permitted, but we do not plan to early adopt. We plan to adopt this standard on January 1, 2019 and do not expect it to have an impact on our consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842),* which requires lessees to recognize a lease liability and a right-of-use (ROU) asset on the balance sheet for all leases, including operating leases, with terms in excess of 12 months. This ASU modifies the definition of a lease and outlines the recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The standard will not apply to our leases of mineral rights to explore for or use oil and natural gas resources, including the intangible rights to explore for those natural resources and rights to use the land in which those natural resources are contained. We plan to make certain elections permitting us to not reassess whether any expired or existing contracts contained leases, permitting us to not reassess the lease classification for any expired or existing leases (all existing leases that were classified as operating leases in accordance with Topic 840 will be classified as operating leases, and all existing leases that were classified as capital leases in accordance with Topic 840 will be classified as finance leases), and permitting us to not reassess initial direct costs for any existing leases. We will also take an election permitting us to continue applying our current policy for land easements that existed as of, or expired before, the effective date and to not recognize a ROU asset or lease liability for short-term leases.

We have completed our assessment of contracts potentially affected by the new standard and have completed our assessment of the accounting treatment for these leases. The adoption will primarily impact other assets and other liabilities and will also impact ongoing disclosures but will not have a material impact on our balance sheet, results of operations or cash flows. We plan to adopt the new standard on January 1, 2019, the effective date, and as permitted by ASU 2018-11 we will not adjust comparative-period financial statements and will continue to apply the guidance in ASC 840, including its disclosure requirements, in the comparative periods presented prior to adoption.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2017 and 2016 to conform to the presentation used for the 2018 consolidated financial statements.

2. Earnings Per Share

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

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

Shares of common stock for the following dilutive securities were excluded from the calculation of diluted EPS as the effect was antidilutive.

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Common stock equivalent of our preferred stock outstanding	60	60	63
Common stock equivalent of our convertible senior notes outstanding	146	146	146
Common stock equivalent of our preferred stock outstanding prior to exchange	—	1	37
Participating securities	1	1	1

3. Debt

Our long-term debt consisted of the following as of December 31, 2018 and 2017:

	December 31, 2018		December 31, 2017	
	Principal Amount	Carrying Amount	Principal Amount	Carrying Amount
	($ in millions)			
7.25% senior notes due 2018	—	—	44	44
Floating rate senior notes due 2019	380	380	380	380
6.625% senior notes due 2020	437	437	437	437
6.875% senior notes due 2020	227	227	227	227
6.125% senior notes due 2021	548	548	548	548
5.375% senior notes due 2021	267	267	267	267
4.875% senior notes due 2022	451	451	451	451
8.00% senior secured second lien notes due 2022[(a)]	—	—	1,416	1,895
5.75% senior notes due 2023	338	338	338	338
7.00% senior notes due 2024	850	850	—	—
8.00% senior notes due 2025	1,300	1,291	1,300	1,290
5.5% convertible senior notes due 2026[(b)(c)(d)]	1,250	866	1,250	837
7.5% senior notes due 2026	400	400	—	—
8.00% senior notes due 2027	1,300	1,299	1,300	1,298
2.25% contingent convertible senior notes due 2038[(b)(d)]	1	1	9	8
Term loan due 2021	—	—	1,233	1,233
Revolving credit facility	419	419	781	781
Debt issuance costs	—	(53)	—	(63)
Interest rate derivatives	—	1	—	2
Total debt, net	8,168	7,722	9,981	9,973
Less current maturities of long-term debt, net[(e)]	(381)	(381)	(53)	(52)
Total long-term debt, net	$ 7,787	$ 7,341	$ 9,928	$ 9,921

(a) The carrying amount as of December 31, 2017 included a premium amount of $479 million associated with a troubled debt restructuring. The premium was being amortized based on the effective yield method.

(b) We are required to account for the liability and equity components of our convertible debt instruments separately and to reflect interest expense through the first demand repurchase date, as applicable, at the interest rate of similar nonconvertible debt at the time of issuance. The applicable rates for our 2.25% Contingent Convertible Senior Notes due 2038 and our 5.5% Convertible Senior Notes due 2026 are 8.0% and 11.5%, respectively.

(c) The conversion and redemption provisions of our convertible senior notes are as follows:

Optional Conversion by Holders. Prior to maturity under certain circumstances and at the holder's option, the notes are convertible. The notes may be converted into cash, our common stock, or a combination of cash and common stock, at our election. One triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarterly. During the fourth quarter of 2018, the price of our common stock was below the threshold level and, as a result, the holders do not have the option to convert their notes in the first quarter of 2019 under this provision. The notes are also convertible, at the holder's option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. The notes were not convertible under this provision during the year ended December 31, 2018. Upon conversion of a convertible senior note, the holder will receive cash, common stock or a combination of cash and common stock, at our election, according to the conversion rate specified in the indenture.

The common stock price conversion threshold amount for the convertible senior notes is 130% of the conversion price of $8.568.

Optional Redemption by the Company. We may redeem the convertible senior notes for cash on or after September 15, 2019, if the price of our common stock exceeds 130% of the conversion price during a specified period at a redemption price of 100% of the principal amount of the notes.

Holders' Demand Repurchase Rights. The holders of our 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 upon certain fundamental changes.

(d) The carrying amounts as of December 31, 2018 and 2017, are reflected net of discounts of $384 million and $414 million, respectively, associated with the equity component of our convertible and contingent convertible senior notes. This amount is being amortized based on the effective yield method through the first demand repurchase date as applicable.

(e) As of December 31, 2018, net current maturities of long-term debt includes our Floating Rate Senior Notes due April 2019 and our 2.25% Contingent Convertible Senior Notes due 2038.

Debt maturities for the next five years and thereafter are as follows:

	Principal Amount of Debt Securities
	($ in millions)
2019	$ 381
2020	664
2021	815
2022	451
2023	757
Thereafter	5,100
Total	$ 8,168

Debt Issuances and Retirements 2018

We issued at par $850 million of 7.00% Senior Notes due 2024 ("2024 notes") and $400 million of 7.50% Senior Notes due 2026 ("2026 notes") pursuant to a public offering for net proceeds of approximately $1.236 billion. We may redeem some or all of the 2024 notes at any time prior to April 1, 2021 and some or all of the 2026 notes at any time prior to October 1, 2021, in each case at a price equal to 100% of the principal amount of the notes to be redeemed plus a "make-whole" premium. At any time prior to April 1, 2021, with respect to the 2024 notes, and October 1, 2021, with respect to the 2026 notes, we also may redeem up to 35% of the aggregate principal amount of each series of notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a specified redemption price. In addition, we may redeem some or all of the 2024 notes at any time on or after April 1, 2021 and some or all of the 2026 notes at any time on or after October 1, 2021, in each case at the redemption prices in accordance with the terms of the notes and the indenture and supplemental indenture governing the notes. These senior notes are unsecured obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Our obligations under the senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our direct and indirect wholly owned subsidiaries.

We used the net proceeds from the 2024 and 2026 notes, together with cash on hand and borrowings under the Chesapeake revolving credit facility, to repay in full $1.233 billion of borrowings under our secured term loan due 2021 for $1.285 billion, which included a $52 million make-whole premium. We recorded a loss of approximately $65 million associated with the repayment of the term loan, including the make-whole premium and the write-off of $13 million of associated deferred charges.

We used a portion of the proceeds from the sale of our Utica Shale assets in Ohio to redeem all of the $1.416 billion aggregate principal amount outstanding of our 8.00% Senior Secured Second Lien Notes due 2022 for $1.477 billion. We recorded a gain of approximately $331 million associated with the redemption, including the realization of the remaining $391 million difference in principal and book value due to troubled debt restructuring accounting in 2015, offset by the make-whole premium of $60 million.

We repaid upon maturity $44 million principal amount of our 7.25% Senior Notes due 2018.

As required by the terms of the indenture for our 2.25% Contingent Convertible Senior Notes due 2038 (“2038 notes”), the holders were provided the option to require us to purchase on December 15, 2018, all or a portion of the holders’ 2038 notes at par plus accrued and unpaid interest up to, but excluding, December 15, 2018. On December 17, 2018, we paid an aggregate of approximately $8 million to purchase all of the 2038 notes that were tendered and not withdrawn. An aggregate of $1 million principal amount of the 2038 notes remained outstanding as of December 31, 2018. Subsequent to December 31, 2018, we redeemed these notes at par and discharged the related indenture.

Debt Issuances and Retirements - 2017

We issued through two private placements $1.300 billion aggregate principal amount of unsecured 8.00% Senior Notes due 2027 for net proceeds of approximately $1.285 billion. The first private placement was issued at par and the second private placement was issued at 99.75% of par. Some or all of the notes may be redeemed at any time prior to June 15, 2022, subject to a make-whole premium. We also may redeem some or all of the notes at any time on or after June 15, 2022, at the applicable redemption price in accordance with the terms of the notes and the indenture and supplemental indenture governing the notes. In addition, subject to certain conditions, we may redeem up to 35% of the aggregate principal amount of the notes at any time prior to June 15, 2020, at a price equal to 108% of the principal amount of the notes to be redeemed using the net proceeds of certain equity offerings.

We also issued in a private placement $300 million aggregate principal amount of additional 8.00% Senior Notes due 2025 (“new 2025 notes”) at 101.25% of par for net proceeds of $301 million. The new 2025 notes are an additional issuance of our outstanding 8.00% Senior Notes due 2025, which we issued in 2016 in an original aggregate principal amount of $1.0 billion at 98.52% of par. The new 2025 Notes issued and the previously issued senior notes due 2025 will be treated as a single class of notes under the indenture.

We retired $2.389 billion principal amount of our outstanding senior notes, senior secured second lien notes, contingent convertible notes and term loan through purchases in the open market, tender offers or repayment upon maturity for $2.592 billion using proceeds from the issuances described above. For the open market repurchases and tender offers, we recorded a net aggregate gain of approximately $233 million, including $374 million of premium associated with our 8.00% Senior Secured Second Lien Notes due 2022.

Senior Notes and Convertible Senior Notes

Our senior notes and our convertible senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Our obligations under the senior notes and the convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our direct and indirect wholly owned subsidiaries. See Note 23 for consolidating financial information regarding our guarantor and non-guarantor subsidiaries.

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

Chesapeake Revolving Credit Facility

In 2018, we amended and restated our credit agreement dated December 15, 2014. The amended and restated Chesapeake revolving credit facility matures in September 2023 and the aggregate initial commitment of the lenders and borrowing base under the facility is $3.0 billion. The Chesapeake revolving credit facility provides for an accordion feature, pursuant to which the aggregate commitments thereunder may be increased to up to $4.0 billion from time to time, subject to agreement of the participating lenders and certain other customary conditions. Borrowing base redeterminations will continue to occur semiannually and our next borrowing base redetermination is scheduled for the second quarter of 2019. As of December 31, 2018, we had outstanding borrowings of $419 million under the Chesapeake revolving credit facility and had used $107 million of the Chesapeake revolving credit facility for various letters of credit. We recorded a loss of $3 million associated with certain deferred charges related to the Chesapeake revolving credit facility prior to its amendment and restatement.

Borrowings under the Chesapeake revolving credit facility bear interest at an alternative base rate (ABR) or LIBOR, at our election, plus an applicable margin ranging from 0.50%-2.00% per annum for ABR loans and 1.50%-3.00% per annum for LIBOR loans, depending on the percentage of the borrowing base then being utilized and whether our leverage ratio exceeds 4.00 to 1.

The Chesapeake revolving credit facility is subject to various financial and other covenants. The terms of the revolving credit facility include covenants limiting, among other things, our ability to incur additional indebtedness, make investments or loans, incur liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into transactions with affiliates. The Chesapeake revolving credit facility contains financial covenants that, after the suspension of most of the covenants during the fourth quarter of 2018 as a result of the closing of the sale of certain of our Utica Shale, beginning in the first quarter of 2019, require us to maintain (i) a leverage ratio of not more than 5.50 to 1 through the fiscal quarter ending September 30, 2019, which threshold decreases over time to 4.00 to 1 for the fiscal quarter ending March 31, 2021 and each fiscal quarter thereafter, (ii) a secured leverage ratio of not more than 2.50 to 1 until the later of (x) the fiscal quarter ending March 31, 2021 or (y) the fiscal quarter in when the Company's leverage ratio does not exceed 4.00 to 1 and (iii) a fixed charge coverage ratio of not less than 2.00 to 1 through the fiscal quarter ending December 31, 2019; not less than 2.25 to 1 through the fiscal quarter ending June 30, 2020; and not less than 2.50 to 1 for the fiscal quarter ended September 30, 2020 and thereafter.

For the fiscal quarter ended December 31, 2018, our only applicable financial covenant required us to maintain a leverage ratio of not more than 5.50 to 1.

As of December 31, 2018, we were in compliance with all applicable financial covenants under the credit agreement and we were able to borrow up to the full availability under the Chesapeake revolving credit facility.

Fair Value of Debt

We estimate the fair value of our senior notes based on the market value of our publicly traded debt as determined based on the yield of our senior notes (Level 1). The fair value of all other debt is based on a market approach using estimates provided by an independent investment financial data services firm (Level 2). Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below:

	December 31, 2018		December 31, 2017	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Short-term debt (Level 1)	$ 381	$ 379	$ 52	$ 53
Long-term debt (Level 1)	$ 3,495	$ 3,173	$ 2,633	$ 2,629
Long-term debt (Level 2)	$ 3,846	$ 3,644	$ 7,286	$ 7,301

4. Contingencies and Commitments

Contingencies

Litigation and Regulatory Proceedings

We are 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 or may seek damages and penalties, the amount of which is indeterminate. Our total accrued liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different.

Business Operations. We are involved in various lawsuits and disputes incidental to our business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions.

Regarding royalty claims, we and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits against us allege, among other things, that we used below-market prices, made improper deductions, utilized improper measurement techniques entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL, or similar theories. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The lawsuits seek compensatory, consequential, treble, and punitive damages, restitution and disgorgement of profits, declaratory and injunctive relief regarding our royalty payment practices, pre-and post-judgment interest, and attorney's fees and costs. Plaintiffs have varying royalty provisions in their respective leases, oil and gas law varies from state to state, and royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations. We have resolved a number of these claims through negotiated settlements of past and future royalty obligations and have prevailed in various other lawsuits. We are currently defending numerous lawsuits seeking damages with respect to underpayment of royalties in multiple states where we have operated, including those discussed below.

On December 9, 2015, the Commonwealth of Pennsylvania, by the Office of Attorney General, filed a lawsuit in the Bradford County Court of Common Pleas related to royalty underpayment and lease acquisition and accounting practices with respect to properties in Pennsylvania. The lawsuit, which primarily relates to the Marcellus Shale and Utica Shale, alleges that we violated the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL) by making improper deductions and entering into arrangements with affiliates that resulted in underpayment of royalties. The lawsuit includes other UTPCPL claims and antitrust claims, including that a joint exploration agreement to which we are a party established unlawful market allocation for the acquisition of leases. The lawsuit seeks statutory restitution, civil penalties and costs, as well as a temporary injunction from exploration and drilling activities in Pennsylvania until restitution, penalties and costs have been paid, and a permanent injunction from further violations of the UTPCPL.

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the divestiture of substantially all of our midstream business and most of our gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights, intentional interference with contractual relations, and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources. These lawsuits seek in aggregate compensatory, consequential, treble, and punitive damages, restitution and disgorgement of profits, declaratory and injunctive relief regarding our royalty payment practices, pre-and post-judgment interest, and attorney's fees and costs. On December 20, 2017 and August 9, 2018, we reached tentative settlements to resolve substantially all Pennsylvania civil royalty cases for a total of approximately $35 million.

We believe losses are reasonably possible in certain of the pending royalty cases for which we have not accrued a loss contingency, but we are currently unable to estimate an amount or range of loss or the impact the actions could have on our future results of operations or cash flows. Uncertainties in pending royalty cases generally include the complex nature of the claims and defenses, the potential size of the class in class actions, the scope and types of the properties and agreements involved, and the applicable production years.

We also previously disclosed defending lawsuits alleging various violations of the Sherman Antitrust Act and state antitrust laws. In 2016, putative class action lawsuits were filed in the U.S. District Court for the Western District of Oklahoma and in Oklahoma state courts, and an individual lawsuit was filed in the U.S. District Court of Kansas, in each case against us and other defendants. The lawsuits generally allege that, since 2007 and continuing through April 2013, the defendants conspired to rig bids and depress the market for the purchases of oil and natural gas leasehold interests and properties in the Anadarko Basin containing producing oil and natural gas wells. The lawsuits seek damages, attorney's fees, costs and interest, as well as enjoinment from adopting practices or plans that would restrain competition in a similar manner as alleged in the lawsuits. On April 12, 2018, we reached a tentative settlement to resolve substantially all Oklahoma civil class action antitrust cases for an insignificant amount. The final fairness hearing is set for April 25, 2019.

On July 28, 2017, OOGC America LLC (OOGC) filed a demand for arbitration with the American Arbitration Association against Chesapeake Exploration, L.L.C., our wholly owned subsidiary, in connection with OOGC's purchase of certain oil and gas leases and other assets pursuant to a Purchase and Sale Agreement entered into on October 10, 2010. In connection with the sale, we also entered into a Development Agreement with OOGC, dated November 15, 2010 (the "Development Agreement"), which governs each of our rights and obligations with respect to the sale, including the transportation and marketing of oil and gas. OOGC's breach of contract, breach of agency and fiduciary duties and other claims generally allege, among other things, that we subjected OOGC to excessive rates for gathering and other services provided for under the Development Agreement and interfered with OOGC's right to audit the documents that supported those rates. On November 13, 2018, a unanimous panel denied every claim asserted by OOGC other than OOGC being entitled to a declaration clarifying its audit rights.

On July 24, 2018, Healthcare of Ontario Pension Plan (HOOPP) filed a demand for arbitration with the American Arbitration Association regarding HOOPP's purchase of our interest in Chaparral Energy, Inc. stock for $215 million on January 5, 2014. HOOPP claims that we engaged in material misrepresentations and fraud, and that we violated the Exchange Act and Oklahoma Uniform Securities Act. HOOPP seeks either rescission or $215 million in monetary damages, and in either case, interest, attorney's fees, disgorgement and punitive damages. We intend to vigorously defend these claims.

In February 2019, a putative class action lawsuit in the District Court of Dallas County, Texas was filed against FTS International, Inc. ("FTSI"), certain investment banks, FTSI's directors including certain of our officers and certain shareholders of FTSI including us. The lawsuit alleges various violations of Sections 11 (with respect to certain of our officers in their capacities as directors of FTSI) and 15 (with respect to such officers and us) of the Securities Act of 1933 in connection with public disclosure made during the initial public offering of FTSI. The suit seeks damages in excess of $1,000,000 and attorneys' fees and other expenses. We intend to vigorously defend these claims.

Environmental Contingencies

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

We are named as a defendant in numerous lawsuits in Oklahoma alleging that we and other companies have engaged in activities that have caused earthquakes. These lawsuits seek compensation for injury to real and personal property, diminution of property value, economic losses due to business interruption, interference with the use and enjoyment of property, annoyance and inconvenience, personal injury and emotional distress. In addition, they seek the reimbursement of insurance premiums and the award of punitive damages, attorneys' fees, costs, expenses and interest.

Other Matters

Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to our business operations is likely to have a material adverse effect on our future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Commitments

Operating Leases

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

	December 31, 2018
	($ in millions)
2019	$ 3
2020	1
Total	$ 4

Operating lease expense for the years ended December 31, 2018, 2017 and 2016, was $4 million, $3 million and $5 million, respectively.

Gathering, Processing and Transportation Agreements

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

The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest and royalty interest owners, credits for third-party volumes or future costs under cost-of-service agreements, are presented below:

	December 31, 2018
	($ in millions)
2019	$ 832
2020	774
2021	683
2022	581
2023	470
2024 – 2034	2,431
Total	$ 5,771

In addition, we have entered into long-term agreements for certain natural gas gathering and related services within specified acreage dedication areas in exchange for cost-of-service based fees redetermined annually, or tiered fees based on volumes delivered relative to scheduled volumes. Future gathering fees may vary with the applicable agreement.

Service Contract

We have a contract with a third-party contractor to provide maintenance and other services to our natural gas compressors under capital lease. This commitment is not recorded as an obligation in the accompanying consolidated balance sheets. The aggregate undiscounted minimum future payments under this service contract is detailed below.

	December 31, 2018
	($ in millions)
2019	$ 5
2020	5
2021	5
Total	$ 15

Oil, Natural Gas and NGL Purchase Commitments

We commit to purchase oil, natural gas and NGL from other owners in the properties we operate, including owners associated with our remaining volumetric production payment (VPP) transaction. Production purchases under these arrangements are based on market prices at the time of production, and the purchased oil, natural gas and NGL are resold at market prices. See *Volumetric Production Payments* in Note 14 for further discussion of our VPP transactions.

Other Commitments

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

In connection with acquisitions and divestitures, our purchase and sale agreements generally provide indemnification to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party and/or other specified matters. These indemnifications generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or cannot be quantified at the time of entering into or consummating a particular transaction. For divestitures of oil and natural gas properties, our purchase and sale agreements may require the return of a portion of the proceeds we receive as a result of uncured title or environmental defects.

Certain of our oil and natural gas properties are burdened by non-operating interests, such as royalty and overriding royalty interests, including overriding royalty interests sold through our VPP transactions. As the holder of the working interest from which these interests have been created, we have the responsibility to bear the cost of developing and producing the reserves attributable to these interests. See *Volumetric Production Payments* in Note 14 for further discussion of our VPP transactions.

While executing our strategic priorities, we have incurred certain cash charges, including contract termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity.

5. Other Liabilities

Other current liabilities as of December 31, 2018 and 2017 are detailed below:

	December 31, 2018	December 31, 2017
	($ in millions)	
Revenues and royalties due others	$ 687	$ 612
Accrued drilling and production costs	258	216
Joint interest prepayments received	73	74
Accrued compensation and benefits	202	214
Other accrued taxes	108	43
Other	212	296
Total other current liabilities	$ 1,540	$ 1,455

Other long-term liabilities as of December 31, 2018 and 2017 are detailed below:

	December 31, 2018	December 31, 2017
	($ in millions)	
CHK Utica ORRI conveyance obligation[(a)]	$ —	$ 156
Unrecognized tax benefits	53	101
Other	103	97
Total other long-term liabilities	$ 156	$ 354

(a) In 2018, we repurchased previously conveyed ORRI from the CHK Utica, L.L.C. investors and extinguished our obligation to convey future ORRIs to the CHK Utica, L.L.C. investors for combined consideration of $199 million. The total CHK Utica ORRI conveyance obligation extinguished in 2018 was $183 million, of which, $30 million was recorded in current liabilities and $153 million was recorded in long-term liabilities. The fair value of the consideration allocated to the extinguishment of liability, $122 million, was less than the carrying amount of the conveyance obligation and resulted in a gain of $61 million recognized in other income on our consolidated statement of operations. The fair value of the consideration allocated to the purchase of ORRIs on proved producing properties was $77 million and recorded in proved oil and natural gas properties in our consolidated balance sheet.

6. Capital Lease Obligation

In 2018, we sold our wholly owned subsidiary, Midcon Compression, L.L.C., to a third party and subsequently leased back some natural gas compressors for 38 months. The aggregate undiscounted minimum future lease payments are presented below:

	December 31, 2018
	($ in millions)
2019	$ 10
2020	10
2021	10
Total minimum lease payments	30
Less imputed interest	(3)
Present value of minimum lease payments	27
Less current maturities	(10)
Present value of minimum lease payment, less current maturities	$ 17

7. Revenue Recognition

The FASB issued *Revenue from Contracts with Customers* (Topic 606) superseding virtually all existing revenue recognition guidance. We adopted this new standard in the first quarter of 2018 using the modified retrospective approach. We applied the new standard to all contracts that were not completed as of January 1, 2018 and reflected the aggregate effect of all modifications in determining and allocating the transaction price. The cumulative effect of adoption of $8 million did not have a material impact on our consolidated financial statements. However, the adoption did result in certain purchase and sale contracts being recorded on a net basis, as an agent, rather than on a gross basis, as principal, due to management's evaluation under new considerations within Topic 606 that indicated we do not have control over the specified commodity in purchase and sale contracts with the same counterparty. Such presentation change did not have an impact on income (loss) from operations, earnings per share or cash flows.

In accordance with the new revenue standard requirements, the disclosure of the impact of adoption on our consolidated statements of operations was as follows:

	Before adoption of ASC 606	Adjustments	As Reported
		($ in millions)	
Statement of Operations for the Year Ended December 31, 2018			
Marketing revenues	$ 5,871	$ (795)	$ 5,076
Marketing operating expenses	$ 5,953	$ (795)	$ 5,158

The following table shows revenue disaggregated by operating area and product type, for the year ended December 31, 2018:

	Year Ended December 31, 2018			
	Oil	Natural Gas	NGL	Total
	($ in millions)			
Marcellus	$ —	$ 924	$ —	$ 924
Haynesville	2	836	—	838
Eagle Ford	1,514	173	185	1,872
Powder River Basin	244	68	38	350
Mid-Continent	246	84	55	385
Utica	195	401	224	820
Revenue from contracts with customers	2,201	2,486	502	5,189
Gains (losses) on oil, natural gas and NGL derivatives	124	(147)	(11)	(34)
Oil, natural gas and NGL revenue	$ 2,325	$ 2,339	$ 491	$ 5,155
Marketing revenue from contracts with customers	$ 2,740	$ 1,194	$ 456	$ 4,390
Other marketing revenue	457	229	—	686
Marketing revenue	$ 3,197	$ 1,423	$ 456	$ 5,076

Accounts Receivable

Accounts receivable as of December 31, 2018 and 2017 are detailed below:

	December 31,	
	2018	2017
	($ in millions)	
Oil, natural gas and NGL sales	$ 976	$ 959
Joint interest billings	211	209
Other	77	184
Allowance for doubtful accounts	(17)	(30)
Total accounts receivable, net	$ 1,247	$ 1,322

8. Income Taxes

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

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Current			
Federal	$ —	$ (14)	$ (14)
State	—	5	(5)
Current Income Taxes	—	(9)	(19)
Deferred			
Federal	3	13	(147)
State	(13)	(2)	(24)
Deferred Income Taxes	(10)	11	(171)
Total	$ (10)	$ 2	$ (190)

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

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Income tax expense (benefit) at the federal statutory rate (21%, 35%, 35%)	$ 182	$ 333	$ (1,606)
State income taxes (net of federal income tax benefit)	23	66	(30)
Remeasurement of deferred tax assets and liabilities	—	1,266	—
Change in valuation allowance	(230)	(1,676)	1,423
Other	15	13	23
Total	$ (10)	$ 2	$ (190)

We applied the guidance in SAB 118 when accounting for the enactment-date effect of the Tax Act. At December 31, 2017, we had not completed our accounting for all of the enactment-date income tax effects of the Tax Act under ASC 740, Income Taxes, for certain items as we were waiting on additional guidance to be issued. At December 31, 2018, we have now completed our accounting for all of the enactment-date income tax effects of the Tax Act. The adjustments made during 2018 are considered immaterial but nevertheless are included as a component of income tax expense in our consolidated statement of operations for the year ended December 31, 2018, which is fully offset with an adjustment to the valuation allowance against our net deferred tax asset.

We reassessed the realizability of our deferred tax assets and continue to maintain a valuation allowance against all or substantially all of our net deferred tax asset. The $230 million net decrease in our valuation allowance is reflected as a component of income tax expense in our consolidated statement of operations for the year ended December 31, 2018. This decrease in the valuation allowance is primarily due to offsetting current year tax expense.

Deferred income taxes are provided to reflect temporary differences in the tax basis of assets and liabilities and their reported amounts in the financial statements. The tax-effected temporary differences, tax credits and net operating loss carryforwards that comprise our deferred taxes are as follows:

	Years Ended December 31,	
	2018	2017
	($ in millions)	
Deferred tax liabilities:		
Property, plant and equipment	$ (544)	$ —
Volumetric production payments	(117)	(129)
Carrying value of debt	(95)	—
Derivative instruments	(56)	—
Other	(7)	(20)
Deferred tax liabilities	(819)	(149)
Deferred tax assets:		
Property, plant and equipment	—	1
Net operating loss carryforwards	2,737	2,248
Carrying value of debt	—	161
Disallowed business interest carryforward	194	—
Asset retirement obligations	40	42
Investments	132	161
Derivative instruments	—	17
Accrued liabilities	89	125
Other	60	71
Deferred tax assets	3,252	2,826
Valuation allowance	(2,433)	(2,674)
Net deferred tax assets	819	152
Net deferred tax assets	$ —	$ 3

As of December 31, 2018, we had federal NOL carryforwards of approximately $10.138 billion and state NOL carryforwards of approximately $10.688 billion, which excludes the NOL carryforwards related to unrecognized tax benefits. The associated deferred tax assets related to these federal and state NOL carryforwards were $2.129 billion and $608 million, respectively. The federal NOL carryforwards generated in tax years prior to 2018 expire between 2031 and 2037. As a result of the Tax Act, the 2018 federal NOL carryforward has no expiration. The value of these carryforwards depends on our ability to generate future taxable income. As of December 31, 2018 and 2017, we had deferred tax assets of $3.252 billion and $2.826 billion upon which we had a valuation allowance of $2.433 billion and $2.674 billion, respectively. Of the net change in the valuation allowance of $241 million for both federal and state deferred tax assets, $230 million is reflected as a component of income tax expense in the consolidated statement of operations and the remainder is reflected in components of stockholders' equity.

A valuation allowance against deferred tax assets, including NOL carryforwards and disallowed business interest, is recognized when it is more likely than not that all or some portion of the benefit from the deferred tax assets will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, and we consider the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of existing taxable temporary differences, and tax planning strategies, as well as the current and forecasted business economics of our industry. Management assesses all available evidence, both positive and negative, to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objectively verifiable negative evidence is the cumulative loss incurred over the three-year period ended December 31, 2018. Such objective negative evidence limits our ability to consider various forms of subjective positive evidence, such as our projections for future income. Accordingly, management has not changed its judgment for the period ended December 31, 2018 with respect to the need for a valuation allowance against all or substantially all of our net deferred tax asset position. The amount of the deferred tax asset considered realizable could be adjusted if projections of future taxable income are increased and/or if objective negative evidence in the form of cumulative losses is no longer present. Based on our current forecast, we may come out of a three-year cumulative loss position during 2019. Should we return to a level of sustained profitability as forecasted, consideration will need to be given to future projections of taxable income to determine whether such projections provide an adequate source of taxable income for the realization of our deferred tax assets, namely federal NOL carryforwards and disallowed business interest carryforwards. If so, then all or a portion of the valuation allowance could possibly be released as early as 2019.

Our ability to utilize NOL carryforwards and possibly other tax attributes to reduce future federal taxable income and federal income tax is subject to various limitations under Section 382 of the Code. The utilization of these attributes may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders (as such shareholders are defined in Treasury regulations), and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of Chesapeake.

As of December 31, 2018, we do not believe that an ownership change has occurred that would limit the utilization of our NOL carryforwards and other tax attributes. Certain future transactions involving our equity (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOL carryforwards and possibly other tax attributes.

Accounting guidance for recognizing and measuring uncertain tax positions requires a more likely than not threshold condition be met on a tax position, based solely on the technical merits of being sustained, before any benefit of the tax position can be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of uncertain tax positions. As of December 31, 2018 and 2017, the amount of unrecognized tax benefits related to NOL carryforwards and tax liabilities associated with uncertain tax positions was $79 million and $106 million, respectively. Of the 2018 amount, $32 million is related to state tax liabilities, $29 million is related to state tax receivables not expected to be recovered and the remainder is related to NOL carryforwards. Of the 2017 amount, $74 million is related to state tax liabilities, $4 million is related to federal tax liabilities and the remainder is related to NOL carryforwards. If recognized, $61 million of the uncertain tax positions identified would have an effect on the effective tax rate. No material changes to the current uncertain tax positions are expected within the next 12 months. As of December 31, 2018 and 2017, we had accrued liabilities of $20 million and $23 million, respectively, for interest related to these uncertain tax positions. We recognize interest related to uncertain tax positions as a component of interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

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

	2018	2017	2016
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 106	$ 202	$ 280
Additions based on tax positions related to the current year	—	—	—
Additions to tax positions of prior years	—	4	33
Settlements	—	(100)	(111)
Expiration of the applicable statute of limitations	(23)	—	—
Reductions to tax positions of prior years	(4)	—	—
Unrecognized tax benefits at end of period	$ 79	$ 106	$ 202

Our federal and state income tax returns are subject to examination by federal and state tax authorities. Federal examination cycles 2010 through 2013 and 2014 through 2015 were settled with the Internal Revenue Service (IRS) during the first and third quarters of 2018, respectively. However, certain of these tax years remain open for purposes of adjusting federal net operating loss carryforwards upon utilization. Tax years 2016 through 2018 remain open for all purposes of examination by the IRS. In addition, tax years 2016 through 2018 as well as certain earlier years remain open for examination by state tax authorities. Currently, several state examinations are in progress of various years. We do not anticipate that the outcome of any state audit will have a significant impact on our results of operations or financial position.

9. Related Party Transactions

Our equity method investees are considered related parties. Hydraulic fracturing and other services are provided to us in the ordinary course of business by our equity affiliate FTSI. As well operators, we are reimbursed by other working interest owners through the joint interest billing process for their proportionate share of these costs. For the years ended December 31, 2018, 2017 and 2016, our expenditures for hydraulic fracturing services with FTSI were $93 million, $111 million and $3 million, respectively.

10. Equity

Common Stock

A summary of the changes in our common shares issued for the years ended December 31, 2018, 2017 and 2016 is detailed below:

	Years Ended December 31, 2018	2017	2016
	(in thousands)		
Shares issued as of January 1	908,733	896,279	664,796
Restricted stock issuances (net of forfeitures and cancellations)	4,983	2,488	1,945
Exchange/conversion of preferred stock	—	9,966	120,186
Exchange of convertible notes	—	—	55,428
Exchange of senior notes	—	—	53,924
Shares issued as of December 31	913,716	908,733	896,279

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2018:

Preferred Stock Series	Issue Date	Liquidation Preference per Share	Holder's Conversion Right	Conversion Rate	Conversion Price	Company's Conversion Right From	Company's Market Conversion Trigger[(a)]
5.75% cumulative convertible non-voting	May and June 2010	$ 1,000	Any time	39.6858	$ 25.1979	May 17, 2015	$ 32.7573
5.75% (series A) cumulative convertible non-voting	May 2010	$ 1,000	Any time	38.3508	$ 26.0751	May 17, 2015	$ 33.8976
4.50% cumulative convertible	September 2005	$ 100	Any time	2.4561	$ 40.7152	September 15, 2010	$ 52.9298
5.00% cumulative convertible (series 2005B)	November 2005	$ 100	Any time	2.7745	$ 36.0431	November 15, 2010	$ 46.8560

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

Outstanding shares of our preferred stock for the years ended December 31, 2018, 2017 and 2016 are detailed below:

	5.75%	5.75% (Series A)	4.50%	5.00% (Series 2005B)
	(in thousands)			
Shares outstanding as of January 1, 2018 and December 31, 2018	770	463	2,559	1,811
Shares outstanding as of January 1, 2017	843	476	2,559	1,962
Preferred stock conversions/exchanges[(a)]	(73)	(13)	—	(151)
Shares outstanding as of December 31, 2017	770	463	2,559	1,811
Shares outstanding as of January 1, 2016	1,497	1,100	2,559	2,096
Preferred stock conversions/exchanges[(b)]	(654)	(624)	—	(134)
Shares outstanding as of December 31, 2016	843	476	2,559	1,962

(a) During 2017, holders of our 5.75% Cumulative Convertible Preferred Stock exchanged 72,600 shares into 7,442,156 shares of common stock, holders of our 5.75% (Series A) Cumulative Convertible Preferred Stock exchanged 12,500 shares into 1,205,923 shares of common stock and holders of our 5.00% (Series 2005B) Cumulative Convertible Preferred Stock exchanged 150,948 shares into 1,317,756 shares of common stock. In connection with the exchanges, we recognized a loss equal to the excess of the fair value of all common stock issued in exchange for the preferred stock over the fair value of the common stock issuable pursuant to the original terms of the preferred stock. The loss of $41 million is reflected as a reduction to net income available to common stockholders for the purpose of calculating earnings per common share.

(b) During 2016, holders of our 5.75% Cumulative Convertible Preferred Stock converted 653,872 shares into 59,141,429 shares of common stock, holders of our 5.75% (Series A) Cumulative Convertible Preferred Stock converted 624,137 shares into 60,032,734 shares of common stock and holders of our 5.00% (Series 2005B) Cumulative Convertible Preferred Stock exchanged or converted 134,000 shares into 1,012,032 shares of common stock. In connection with the exchanges noted above, we recognized a loss equal to the excess of the fair value of all common stock issued in exchange for the preferred stock over the fair value of the common stock issuable pursuant to the original terms of the preferred stock. The loss of $428 million is reflected as a reduction to net income available to common stockholders for the purpose of calculating earnings per common share.

Dividends

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

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

In January 2016, we suspended dividend payments on our convertible preferred stock to provide additional liquidity in the depressed commodity price environment. In the first quarter of 2017, we reinstated the payment of dividends on each series of our outstanding convertible preferred stock and paid our dividends in arrears.

Accumulated Other Comprehensive Income (Loss)

For the years ended December 31, 2018 and 2017, changes in accumulated other comprehensive income (loss) for cash flow hedges, net of tax, are detailed below:

	Years Ended December 31,	
	2018	2017
	($ in millions)	
Balance, as of January 1	$ (57)	$ (96)
Other comprehensive income before reclassifications	—	5
Amounts reclassified from accumulated other comprehensive income[(a)]	34	34
Net other comprehensive income	34	39
Balance, as of December 31	$ (23)	$ (57)

(a) Net losses on cash flow hedges for commodity contracts reclassified from accumulated other comprehensive income (loss), net of tax, to oil, natural gas and NGL revenues in the consolidated statements of operations.

Noncontrolling Interests

Chesapeake Granite Wash Trust. We own 23,750,000 common units in the Chesapeake Granite Wash Trust (the Trust) representing a 51% beneficial interest. We have determined that the Trust is a VIE and that we are the primary beneficiary. As a result, the Trust is included in our consolidated financial statements. As of December 31, 2018 and 2017, we had $123 million and $124 million, respectively, of noncontrolling interests on our consolidated balance sheets attributable to the Trust. Net income attributable to the Trust's noncontrolling interest was $4 million for each of the years ended December 31, 2018 and 2017 and net loss attributable to the Trust's noncontrolling interest was $9 million for the year ended December 31, 2016.

The Trust's legal existence is separate from Chesapeake and our other consolidated subsidiaries, and the Trust is not a guarantor of any of Chesapeake's debt. The creditors or beneficial holders of the Trust have no recourse to the general credit of Chesapeake. We have presented parenthetically on the face of the consolidated balance sheets the assets of the Trust that can be used only to settle obligations of the Trust and the liabilities of the Trust for which creditors do not have recourse to the general credit of Chesapeake.

11. Share-Based Compensation

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

Share-Based Compensation Plans

2014 Long Term Incentive Plan. Our 2014 Long Term Incentive Plan (2014 LTIP), which is administered by the Compensation Committee of our Board of Directors, became effective on June 13, 2014 after it was approved by shareholders at our 2014 Annual Meeting. The 2014 LTIP replaced our Amended and Restated Long Term Incentive Plan which was adopted in 2005. The 2014 LTIP provides for up to 71,600,000 shares of common stock that may be issued as long-term incentive compensation to our employees and non-employee directors; provided, however, that the 2014 LTIP uses a fungible share pool under which (i) each share issued pursuant to a stock option or stock appreciation right (SAR) reduces the number of shares available under the 2014 LTIP by 1.0 share; (ii) each share issued pursuant to awards other than options and SARs reduces the number of shares available by 2.12 shares; (iii) if any awards of restricted stock under the 2014 LTIP, or its predecessor plan, are forfeited, expire, are settled for cash, or are tendered by the participant or withheld by us to satisfy any tax withholding obligation, then the shares subject to the award may be used again for awards; and (iv) PSUs and other performance awards which are payable solely in cash are not counted against the aggregate number of shares issuable. In addition, the 2014 LTIP prohibits the reuse of shares withheld or delivered to satisfy the exercise price of, or to satisfy tax withholding requirements for, an option or SAR. The 2014 LTIP also prohibits "net share counting" upon the exercise of options or SARs.

The 2014 LTIP authorizes the issuance of the following types of awards: (i) nonqualified and incentive stock options; (ii) SARs; (iii) restricted stock; (iv) performance awards, including PSUs; and (v) other stock-based awards. For both stock options and SARs, the exercise price may not be less than the fair market value of our common stock on the date of grant and the maximum exercise period may not exceed ten years from the date of grant. Awards granted under the plan vest at specified dates and/or upon the satisfaction of certain performance or other criteria, as determined by the Compensation Committee. As of December 31, 2018, 35,389,825 shares of common stock remained issuable under the 2014 LTIP.

Equity-Classified Awards

Restricted Stock. We grant restricted stock to employees and non-employee directors. A summary of the changes in unvested restricted stock during 2018, 2017 and 2016 is presented below:

	Shares of Unvested Restricted Stock	Weighted Average Grant Date Fair Value
	(in thousands)	
Unvested restricted stock as of January 1, 2018	13,178	$ 6.37
Granted	6,067	$ 3.73
Vested	(5,808)	$ 7.67
Forfeited	(1,579)	$ 6.02
Unvested restricted stock as of December 31, 2018	11,858	$ 4.43
Unvested restricted stock as of January 1, 2017	9,092	$ 11.39
Granted	9,872	$ 5.40
Vested	(4,573)	$ 13.73
Forfeited	(1,213)	$ 8.32
Unvested restricted stock as of December 31, 2017	13,178	$ 6.37
Unvested restricted stock as of January 1, 2016	10,455	$ 17.31
Granted	4,604	$ 4.58
Vested	(4,692)	$ 17.23
Forfeited	(1,275)	$ 13.91
Unvested restricted stock as of December 31, 2016	9,092	$ 11.39

The aggregate intrinsic value of restricted stock that vested during 2018 was approximately $20 million based on the stock price at the time of vesting.

As of December 31, 2018, there was approximately $33 million of total unrecognized compensation expense related to unvested restricted stock. The expense is expected to be recognized over a weighted average period of approximately 2.02 years.

Stock Options. In 2018, 2017 and 2016, we granted members of management stock options that vest ratably over a three-year period. Each stock option award has an exercise price equal to the closing price of our common stock on the grant date. Outstanding options expire seven years to ten years from the date of grant.

We utilize the Black-Scholes option pricing model to measure the fair value of stock options. The expected life of an option is determined using the simplified method. Volatility assumptions are estimated based on the average of historical volatility of Chesapeake stock over the expected life of an option. The risk-free interest rate is based on the U.S. Treasury rate in effect at the time of the grant over the expected life of the option. The dividend yield is based on an annual dividend yield, taking into account our dividend policy, over the expected life of the option. We used the following weighted average assumptions to estimate the grant date fair value of the stock options granted in 2018:

Expected option life – years	6.0
Volatility	63.55%
Risk-free interest rate	2.72%
Dividend yield	—%

The following table provides information related to stock option activity for 2018, 2017 and 2016:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share		Weighted Average Contract Life in Years	Aggregate Intrinsic Value[a]	
	(in thousands)				($ in millions)	
Outstanding as of January 1, 2018	16,285	$	8.25	7.73	$	1
Granted	3,611	$	3.01			
Exercised	—	$	—		$	—
Expired	(602)	$	13.83			
Forfeited	(1,198)	$	5.45			
Outstanding as of December 31, 2018	18,096	$	7.20	7.15	$	—
Exercisable as of December 31, 2018	8,250	$	10.73	5.73	$	—
Outstanding as of January 1, 2017	8,593	$	11.88	7.22	$	14
Granted	9,226	$	5.45			
Exercised	—	$	—		$	—
Expired	(435)	$	18.50			
Forfeited	(1,099)	$	9.12			
Outstanding as of December 31, 2017	16,285	$	8.25	7.73	$	1
Exercisable as of December 31, 2017	4,474	$	15.15	5.26	$	—
Outstanding as of January 1, 2016	5,377	$	19.37	5.80	$	—
Granted	4,932	$	3.71			
Exercised	—	$	—		$	—
Expired	(771)	$	19.46			
Forfeited	(945)	$	5.66			
Outstanding as of December 31, 2016	8,593	$	11.88	7.22	$	14
Exercisable as of December 31, 2016	2,844	$	19.60	5.53	$	—

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

As of December 31, 2018, there was $13 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 1.56 years.

Restricted Stock and Stock Option Compensation. We recognized the following compensation costs, net of actual forfeitures, related to restricted stock and stock options for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
General and administrative expenses	$ 28	$ 37	$ 38
Oil and natural gas properties	6	12	16
Oil, natural gas and NGL production expenses	5	12	13
Marketing expenses	—	—	1
Total restricted stock and stock option compensation	$ 39	$ 61	$ 68

Liability-Classified Awards

Performance Share Units. We granted PSUs to senior management that vest ratably over a three-year performance period and are settled in cash. The ultimate amount earned is based on achievement of performance metrics established by the Compensation Committee of the Board of Directors. Compensation expense associated with PSU awards is recognized over the service period based on the graded-vesting method. The value of the PSU awards at the end of each reporting period is dependent upon our estimates of the underlying performance measures.

For PSUs granted in 2017 and 2016, performance metrics include a total shareholder return (TSR) component, which can range from 0% to 100% and an operational performance component based on finding and development costs, which can range from 0% to 100%, resulting in a maximum payout of 200%. The payout percentage for the 2016 and 2017 PSU awards is capped at 100% if our absolute TSR is less than zero. The PSUs are settled in cash on the third anniversary of the awards. We utilized a Monte Carlo simulation for the TSR performance measure and the following assumptions to determine the grant date fair value and the reporting date fair value of the 2017 awards. The performance period for the 2016 awards ended on December 31, 2018 and the TSR component has been finalized.

Grant Date Assumptions

Assumption	2017 Awards
Volatility	80.65%
Risk-free interest rate	1.54%
Dividend yield for value of awards	—%

Reporting Date Assumptions

Assumption	2017 Awards
Volatility	64.69%
Risk-free interest rate	2.63%
Dividend yield for value of awards	—%

As the above assumptions and expected satisfaction of performance metrics change, the PSU liabilities will be adjusted quarterly through the end of the performance period.

For PSUs granted in 2018, performance metrics include an operational performance component based on a ratio of cumulative earnings before interest expense, income taxes, and depreciation, depletion and amortization expense (EBITDA) to capital expenditures, for which payout can range from 0% to 200%. The vested PSUs are settled in cash on each of the three annual vesting dates. We used the closing price of our common stock on the grant date to determine the grant date fair value of the PSUs. The PSU liability will be adjusted quarterly, based on changes in our stock price and expected satisfaction of performance metrics, through the end of each vesting period.

Cash Restricted Stock Units. In 2018, we granted CRSUs to employees that vest straight-line over a three-year period and are settled in cash on each of the three annual vesting dates. The ultimate amount earned is based on the closing price of our common stock on each of the vesting dates. We used the closing price of our common stock on the grant date to determine the grant date fair value of the CRSUs. The CRSU liability will be adjusted quarterly, based on changes in our stock price, through the end of each vesting period.

The following table presents a summary of our liability-classified awards:

	Units	Grant Date Fair Value	December 31, 2018 Fair Value	December 31, 2018 Vested Liability
		($ in millions)	($ in millions)	
2018 PSU Awards:				
Payable 2019, 2020 and 2021	3,959,647	$ 12	$ 11	$ —
2017 PSU Awards:				
Payable 2020	1,217,774	$ 8	$ 3	$ 1
2016 PSU Awards:				
Payable 2019	2,348,893	$ 10	$ 6	$ 4
2018 CRSU Awards:				
Payable 2019, 2020 and 2021	15,189,197	$ 46	$ 32	$ —

We recognized the following compensation costs (credits), net of actual forfeitures, related to our liability-classified awards for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31, 2018	2017	2016
		($ in millions)	
General and administrative expenses	$ 7	$ (4)	$ 14
Oil and natural gas properties	3	—	—
Oil, natural gas and NGL production expenses	2	—	—
Restructuring and other termination costs	—	—	1
Total liability-classified awards compensation	$ 12	$ (4)	$ 15

12. Employee Benefit Plans

Our qualified 401(k) profit sharing plan (401(k) Plan) is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) Plan accounts, subject to plan limits and those set by the IRS. We match employee contributions dollar for dollar (subject to a maximum contribution of 15% of an employee's base salary and performance bonus) in cash. We contributed $31 million, $35 million and $39 million to the 401(k) Plan in 2018, 2017 and 2016, respectively.

We also maintain a nonqualified deferred compensation plan (DC Plan). To be eligible to participate in the DC Plan, an active employee must have a base salary of at least $150,000, have a hire date on or before December 1, immediately preceding the year in which the employee is able to participate, or be designated as eligible to participate. We match 100% of employee contributions up to 15% of base salary and performance bonus in the aggregate for the DC Plan with Chesapeake common stock, and an employee who is at least age 55 may elect for the matching contributions to be made in any one of the DC Plan’s investment options. The maximum compensation that can be deferred by employees under all of our deferred compensation plans, including the Chesapeake 401(k) Plan, is a total of 75% of base salary and 100% of performance bonus. The participant may choose separate deferral election percentages for both plans. We contributed $7 million, $8 million and $9 million to the DC Plan during 2018, 2017 and 2016, respectively, to fund the match. The deferred compensation company match of 15% has a five-year vesting schedule based on years of service. Any participant who is active on December 31 of the plan year will receive the deferred compensation company match which will be awarded on an annual basis.

Any assets placed in trust by us to fund future obligations of our DC Plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the Company as to their deferred compensation in the plan.

13. Derivative and Hedging Activities

We use derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility. All of our oil, natural gas and NGL derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty. None of our open oil, natural gas and NGL derivative instruments were designated for hedge accounting as of December 31, 2018 and 2017.

Oil, Natural Gas and NGL Derivatives

As of December 31, 2018 and 2017, our oil, natural gas and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*: We receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. In exchange for higher fixed prices on certain of our swap trades, we may sell call options and call swaptions.
- *Options*: We sell, and occasionally buy, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the counterparty the excess on sold call options and we receive the excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
- *Call Swaptions*: We sell call swaptions to counterparties in exchange for a premium that allow the counterparty, on a specific date, to extend an existing fixed-price swap for a certain period of time.
- *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, we receive the fixed price and pay 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 the sale by us of an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option strike price.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. We receive the fixed price differential and pay the floating market price differential to the counterparty for the hedged commodity.

The estimated fair values of our oil, natural gas and NGL derivative instrument assets (liabilities) as of December 31, 2018 and 2017 are provided below:

	December 31, 2018		December 31, 2017	
	Notional Volume	Fair Value	Notional Volume	Fair Value
		($ in millions)		($ in millions)
Oil (mmbbl):				
Fixed-price swaps	12	$ 157	21	$ (151)
Collars	8	98	—	—
Three-way collars	—	—	2	(10)
Call swaptions	—	—	2	(13)
Basis protection swaps	7	5	11	(9)
Total oil	27	260	36	(183)
Natural gas (bcf):				
Fixed-price swaps	623	26	532	149
Three-way collars	88	1	—	—
Collars	55	(3)	47	11
Call options	44	—	110	(3)
Call swaptions	106	(9)	—	—
Basis protection swaps	50	—	65	(7)
Total natural gas	966	15	754	150
NGL (mmgal):				
Fixed-price swaps	—	—	33	(2)
Contingent Consideration:				
Utica divestiture		7		—
Total estimated fair value		$ 282		$ (35)

We have terminated certain commodity derivative contracts that were previously designated as cash flow hedges for which the original contract months are yet to occur. See further discussion below under *Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss)*.

Contingent Consideration Arrangements

In 2018, we sold our Utica Shale position to Encino. The agreement includes additional contingent payments to us of up to $100 million comprised of $50 million in consideration in each case if, on or prior to December 31, 2019, there is a period of twenty (20) trading days out of a period of thirty (30) consecutive trading days where (i) the average of the NYMEX natural gas strip prices for the months comprising the year 2022 equals or exceeds $3.00/mmbtu as calculated pursuant to the purchase agreement, and (ii) the average of the NYMEX natural gas strip price for the months comprising the year 2023 equals or exceeds $3.25/mmbtu as calculated pursuant to the purchase agreement. See Note 14 for further details regarding the transaction.

Foreign Currency Derivatives

During 2017, both our 6.25% Euro-denominated Senior Notes due 2017 and cross currency swaps for the same principal amount matured. Upon maturity of the notes, the counterparties paid us €246 million and we paid the counterparties $327 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. The swaps were designated as cash flow hedges and, because they were entirely effective in having eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates, changes in their fair value did not impact earnings.

Supply Contract Derivatives

In 2016, we sold a long-term natural gas supply contract to a third party for cash proceeds of $146 million, which is included in marketing revenue as a realized gain. We reversed the cumulative unrealized gains, resulting in an unrealized loss of $297 million.

Effect of Derivative Instruments – Consolidated Balance Sheets

The following table presents the fair value and location of each classification of derivative instrument included in the consolidated balance sheets as of December 31, 2018 and 2017 on a gross basis and after same-counterparty netting:

Balance Sheet Classification	Gross Fair Value	Amounts Netted in the Consolidated Balance Sheets	Net Fair Value Presented in the Consolidated Balance Sheets
		($ in millions)	
As of December 31, 2018			
Commodity Contracts:			
Short-term derivative asset	$ 306	$ (104)	$ 202
Long-term derivative asset	117	(41)	76
Short-term derivative liability	(107)	104	(3)
Long-term derivative liability	(41)	41	—
Contingent Consideration:			
Short-term derivative asset	7	—	7
Total derivatives	$ 282	$ —	$ 282
As of December 31, 2017			
Commodity Contracts:			
Short-term derivative asset	$ 157	$ (130)	$ 27
Short-term derivative liability	(188)	130	(58)
Long-term derivative liability	(4)	—	(4)
Total derivatives	$ (35)	$ —	$ (35)

As of December 31, 2018 and 2017, we did not have any cash collateral balances for these derivatives.

Effect of Derivative Instruments – Consolidated Statements of Operations

The components of oil, natural gas and NGL revenues for the years ended December 31, 2018, 2017 and 2016 are presented below:

	Years Ended December 31, 2018	2017	2016
	($ in millions)		
Oil, natural gas and NGL revenues	$ 5,189	$ 4,574	$ 3,866
Gains (losses) on undesignated oil, natural gas and NGL derivatives	—	445	(545)
Losses on terminated cash flow hedges	(34)	(34)	(33)
Total oil, natural gas and NGL revenues	$ 5,155	$ 4,985	$ 3,288

The components of marketing revenues for the years ended December 31, 2018, 2017 and 2016 are presented below:

	Years Ended December 31, 2018	2017	2016
	($ in millions)		
Marketing revenues	$ 5,069	$ 4,511	$ 4,881
Gains on undesignated marketing natural gas derivatives	7	—	—
Losses on undesignated supply contract derivatives	—	—	(297)
Total marketing revenues	$ 5,076	$ 4,511	$ 4,584

Gains as a result of changes in the fair value of our contingent consideration arrangements are recognized in loss on sale of oil and natural gas properties in the consolidated statement of operations.

Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss)

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

	Years Ended December 31, 2018		2017		2016	
	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)					
Balance, beginning of period	$ (114)	$ (57)	$ (153)	$ (96)	$ (160)	$ (99)
Net change in fair value	—	—	5	5	(27)	(13)
Losses reclassified to income	34	34	34	34	34	16
Balance, end of period	$ (80)	$ (23)	$ (114)	$ (57)	$ (153)	$ (96)

The accumulated other comprehensive loss as of December 31, 2018 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the original contract months are yet to occur. Remaining deferred gain or loss amounts will be recognized in earnings in the month for which the original contract months are to occur. As of December 31, 2018, we expect to transfer approximately $34 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. The remaining amounts will be transferred by December 31, 2022.

Credit Risk Considerations

Our derivative instruments expose us to our counterparties' credit risk. To mitigate this risk, we enter into derivative contracts only with counterparties that are highly rated or deemed by us to have acceptable credit strength 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, 2018, our oil, natural gas and NGL derivative instruments were spread among 11 counterparties.

Hedging Arrangements

Certain of our hedging arrangements are with counterparties that are also lenders (or affiliates of lenders) under the Chesapeake revolving credit facility. The contracts entered into with these counterparties are secured by the same collateral that secures the Chesapeake revolving credit facility. In addition, we enter into bilateral hedging agreements with other counterparties. The counterparties' and our obligations under the bilateral hedging agreements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds. As of December 31, 2018, we posted an immaterial amount in letters of credit as collateral for our commodity derivatives. No cash was posted as collateral for our commodity derivatives.

Fair Value

The fair value of our derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as oil, natural gas and NGL forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are compared to the values given by our counterparties for reasonableness. Since oil, natural gas and NGL swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. All other derivatives have some level of unobservable input, such as volatility curves, and are therefore classified as Level 3. Derivatives are also subject to the risk that either party to a contract will be unable to meet its obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date, this has not had a material impact on the values of our derivatives.

The following table provides information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2018 and 2017:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
As of December 31, 2018				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 319	$ 103	$ 422
Commodity liabilities	—	(131)	(16)	(147)
Utica divestiture contingent consideration	—	—	7	7
Total derivatives	$ —	$ 188	$ 94	$ 282
As of December 31, 2017				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ —	$ 8	$ 8
Commodity liabilities	—	(20)	(23)	(43)
Total derivatives	$ —	$ (20)	$ (15)	$ (35)

A summary of the changes in the fair values of our financial assets (liabilities) classified as Level 3 during 2018 and 2017 is presented below:

	Commodity Derivatives	Utica Contingent Consideration
	($ in millions)	
Balance, as of January 1, 2018	$ (15)	$ —
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	77	7
Total purchases, issuances, sales and settlements:		
Settlements	25	—
Balance, as of December 31, 2018	$ 87	$ 7
Balance, as of January 1, 2017	$ (10)	$ —
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	2	—
Total purchases, issuances, sales and settlements:		
Settlements	(7)	—
Balance, as of December 31, 2017	$ (15)	$ —

(a)

	Commodity Derivatives 2018	Commodity Derivatives 2017	Utica Contingent Consideration 2018	Utica Contingent Consideration 2017
	($ in millions)			
Total gains included in earnings for the period	$ 77	$ 2	$ 7	$ —
Change in unrealized gains (losses) related to assets still held at reporting date	$ 86	$ (14)	$ 7	$ —

Qualitative and Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

The significant unobservable inputs for Level 3 derivative contracts include market volatility. Changes in market volatility impact the fair value measurement of our derivative contracts, which is based on an estimate derived from option models. For example, an increase or decrease in the forward prices and volatility of oil and natural gas prices decreases or increases the fair value of oil and natural gas derivatives. The following table presents quantitative information about Level 3 inputs used in the fair value measurement of our commodity derivative contracts as of December 31, 2018:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value December 31, 2018
				($ in millions)
Oil trades	Oil price volatility curves	23.70% – 42.17%	32.51%	$ 98
Natural gas trades	Natural gas price volatility curves	12.88% – 90.93%	24.93%	$ (11)
Utica contingent consideration	Natural gas price volatility curves	10.36% – 57.66%	—	$ 7

14. Oil and Natural Gas Property Transactions

Under full cost accounting rules, we accounted for the sales of oil and natural gas properties as adjustments to capitalized costs, with no recognition of gain or loss unless a sale involves a significant change in proved reserves and significantly alters the relationship between capitalized costs and proved reserves.

2018 Transactions

We sold all of our approximately 1,500,000 gross (900,000 net) acres in Ohio, of which approximately 320,000 net acres are prospective for the Utica Shale with approximately 920 producing wells, along with related property and equipment (collectively, the “Designated Properties”) for net proceeds of $1.868 billion to Encino, with additional contingent payments to us of up to $100 million comprised of $50 million in consideration in each case if, on or prior to December 31, 2019, there is a period of twenty (20) trading days out of a period of thirty (30) consecutive trading days where (i) the average of the NYMEX natural gas strip prices for the months comprising the year 2022 equals or exceeds $3.00/mmbtu as calculated pursuant to the purchase agreement, and (ii) the average of the NYMEX natural gas strip prices for the months comprising the year 2023 equals or exceeds $3.25/mmbtu as calculated pursuant to the purchase agreement.

The sale of our Designated Properties to Encino involved a significant change in proved reserves and significantly altered the relationship between costs and proved reserves and therefore resulted in the recognition of loss of approximately $578 million. Under SEC rules for full cost companies, a transaction is deemed to be significant if the properties being sold represent 25% or more of the reserve quantities of the divesting company.

In 2018, we sold portions of our acreage, producing properties and other related property and equipment in the Mid-Continent, including our Mississippian Lime assets, for approximately $491 million, subject to certain customary closing adjustments. Included in the sales were approximately 238,500 net acres and interests in approximately 3,200 wells. Also, in 2018, we received proceeds of approximately $37 million subject to customary closing adjustments, for the sale of other oil and natural gas properties covering various operating areas.

2017 Transactions

We sold portions of our acreage and producing properties in our Haynesville Shale operating area in northern Louisiana for approximately $915 million, subject to certain customary closing adjustments. Included in the sales were approximately 119,500 net acres and interests in 576 wells that were producing approximately 80 mmcf of gas per day at the time of closing.

We received proceeds of approximately $350 million, net of post-closing adjustments, for the sale of other oil and natural gas properties covering various operating areas.

2016 Transactions

We conveyed our interests in the Barnett Shale operating area located in north central Texas and received from the buyer aggregate net proceeds of approximately $218 million. We sold approximately 212,000 net developed and undeveloped acres along with other property and equipment. We simultaneously terminated most of our future commitments associated with this asset. In connection with this disposition, we paid $361 million to terminate certain natural gas gathering and transportation agreements and paid $58 million to restructure a long-term sales agreement. We recognized $361 million of expense for the termination of contracts and deferred charges of $58 million for the restructured contract. The deferred charges will be amortized to marketing, gathering and compression revenue over the life of the agreement. Additionally, we recognized a charge of $284 million in 2016 related to the impairment of other fixed assets sold in the divestiture.

We sold the majority of our upstream and midstream assets in the Devonian Shale located in West Virginia, Kentucky and Virginia for proceeds of $140 million. We sold an interest in approximately 1.3 million net acres, retaining all rights below the base of the Kope formation, and approximately 5,300 wells along with related gathering assets, and other property and equipment. Additionally, we recognized an impairment charge of $142 million in 2016 related to other fixed assets sold in the divestiture. In connection with this divestiture, we purchased the underlying interests in one of our remaining VPP transactions for $127 million. All of the acquired interests were conveyed in our divestiture and we no longer have any future obligations related to this VPP.

We acquired oil and natural gas properties in the Haynesville Shale for approximately $85 million.

We sold certain of our other noncore oil and natural gas properties for net proceeds of approximately $1.048 billion, after post-closing adjustments. In conjunction with certain of these sales, we purchased oil and natural gas interests previously sold to third parties in connection with four of our VPP transactions for approximately $259 million. Substantially all of the acquired interests were part of the asset divestitures discussed above and we no longer have any further commitments or obligations related to these VPPs. The asset divestitures cover various operating areas.

Volumetric Production Payments

A VPP is a limited-term overriding royalty interest in oil and natural gas 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 non-recourse to the seller (i.e., the purchaser's only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain all production beyond the specified volumes, if any, after the scheduled production volumes have been delivered. If contractually scheduled volumes exceed the actual volumes produced from the VPP wellbores that are attributable to the ORRI conveyed, either the shortfall will be made up from future production from these wellbores (or, at our option, from our retained interest in the wellbores) through an adjustment mechanism, or the initial term of the VPP will be extended until all scheduled volumes, to the extent produced, are delivered from the VPP wellbores to the VPP buyer. We retain drilling rights on the properties below currently producing intervals and outside of producing wellbores.

As the operator of the properties from which the VPP volumes have been sold, we bear the cost of producing the reserves attributable to these interests, which we include as a component of production expenses and production taxes in our consolidated statements of operations in the periods these 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. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. Future costs will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which the production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all.

We have committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

In connection with certain asset divestitures in 2016, we purchased the remaining oil and natural gas interests previously sold in connection with VPP #10, VPP #4, VPP #3, VPP #2 and VPP #1. A majority of the oil and natural gas interests purchased were subsequently sold to the buyers of the assets.

As of December 31, 2018, we had the following VPP outstanding:

				Volume Sold			
VPP #	Date of VPP	Location	Proceeds	Oil	Natural Gas	NGL	Total
			($ in millions)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	May 2011	Mid-Continent	$ 853	1.7	138	4.8	177

The volumes remaining to be delivered on behalf of our VPP buyers as of December 31, 2018 were as follows:

		Volume Remaining as of December 31, 2018			
VPP #	Term Remaining	Oil	Natural Gas	NGL	Total
	(in months)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	26	0.2	23.1	0.6	28.1

15. Other Property and Equipment

Other Property and Equipment

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

	December 31, 2018	December 31, 2017	Estimated Useful Life
	($ in millions)		(in years)
Buildings and improvements	$ 1,053	$ 1,093	10 – 39
Computer equipment	353	345	5
Natural gas compressors[(a)]	48	235	3 – 20
Land	106	126	
Other	161	187	5 – 20
Total other property and equipment, at cost	1,721	1,986	
Less: accumulated depreciation	(630)	(672)	
Total other property and equipment, net	$ 1,091	$ 1,314	

(a) Includes assets under capital lease of $27 million, less accumulated depreciation of $1 million, as of December 31, 2018. The related amortization expense for assets under capital lease is included in depreciation, depletion and amortization expense on our consolidated statement of operations.

16. Investments

In 2018, FTS International, Inc. (NYSE: FTSI) completed an initial public offering. Due to the offering, the ownership percentage of our equity method investment in FTSI decreased from approximately 29% to 24% and resulted in a gain of $78 million. In addition, we sold approximately 4.3 million shares of FTSI in the offering for net proceeds of approximately $74 million and recognized a gain of $61 million decreasing our ownership percentage to approximately 20%. We continue to hold approximately 22.0 million shares in the publicly traded company. In 2016, we recognized an other-than-temporary impairment of $119 million related to our Sundrop investment.

17. Impairments

Impairments of Oil and Natural Gas Properties

Our proved oil and natural gas properties are subject to quarterly full cost ceiling tests. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. Estimated future net revenues for the quarterly ceiling limit are calculated using the average of commodity prices on the first day of the month over the trailing 12-month period. In 2018 and 2017, we did not have an impairment for our oil and natural gas properties. In 2016, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in an impairment in the carrying value of our oil and natural gas properties of $2.564 billion.

Impairments of Fixed Assets

We review our long-lived assets, other than oil and natural gas properties, for recoverability whenever events or changes in circumstances indicate that carrying amounts may not be recoverable. We recognize an impairment if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. A summary of our impairments of fixed assets by asset class and other charges for the years ended December 31, 2018, 2017 and 2016 is as follows:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Natural gas compressors	$ 45	$ —	$ 21
Barnett Shale exit costs	—	—	284
Devonian Shale exit costs	—	—	142
Gathering systems	—	—	3
Buildings and land	4	5	11
Other	4	—	—
Total impairments of fixed assets and other	$ 53	$ 5	$ 461

Natural Gas Compressors. In 2018, we recorded a $45 million impairment related to 890 compressors for the difference between carrying value and the fair value of the assets. In 2016, we recorded a $13 million impairment related to obsolescence of 205 compressors. Additionally in 2016, we recorded an $8 million impairment related to 155 compressors for the difference between the aggregate sales price and carrying value.

Barnett Shale Exit Costs. In 2016, we conveyed our interests in the Barnett Shale operating area located in north central Texas and recognized an impairment charge of $284 million related to other fixed assets sold in the divestiture.

Devonian Shale Exit Costs. In 2016, we sold the majority of our upstream and midstream assets in the Devonian Shale located in West Virginia and Kentucky. We recognized an impairment charge of $142 million in 2016 related to other fixed assets sold in the divestiture.

Nonrecurring Fair Value Measurements. Fair value measurements for certain of the impairments were based on recent sales information for comparable assets. As the fair value was estimated using the market approach based on recent prices from orderly sales transactions for comparable assets between market participants, these values were classified as Level 2 in the fair value hierarchy. Other inputs used were not observable in the market; these values were classified as Level 3 in the fair value hierarchy.

18. Other Operating Expense

In 2017, we terminated future natural gas transportation commitments related to divested assets for cash payments of $126 million. Also in 2017, we paid $290 million to assign an oil transportation agreement to a third party. In 2016, we conveyed our interests in the Barnett Shale operating area located in north central Texas and simultaneously terminated most of our future commitments associated with this asset. As a result of this transaction, we recognized $361 million of charges related to the termination of natural gas gathering and transportation agreements.

19. Restructuring and Other Termination Costs

Workforce Reductions

In 2018, we underwent a reduction in workforce impacting approximately 13% of employees across all functions, primarily on our Oklahoma City campus. In connection with the reduction, we incurred a total charge of approximately $38 million for one-time termination benefits. The following table summarizes our restructuring liabilities:

	Other Current Liabilities
	($ in millions)
Balance as of December 31, 2017	$ —
Initial restructuring recognition on January 30, 2018	38
Termination benefits paid	(38)
Balance as of December 31, 2018	$ —

In 2016, we recognized $6 million of charges related to a reduction in workforce in connection with the restructuring of our compressor manufacturing subsidiary and the reductions in workforce resulting from the conveyance of our interests in the Barnett Shale and Devonian Shale operating areas.

20. Fair Value Measurements

Recurring Fair Value Measurements

Other Current Assets. Assets related to our deferred compensation plan are included in other current assets. The fair value of these assets is determined using quoted market prices as they consist of exchange-traded securities.

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

Financial Assets (Liabilities). The following table provides fair value measurement information for the above-noted financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2018 and 2017:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
	($ in millions)			
As of December 31, 2018				
Financial Assets (Liabilities):				
Other current assets	$ 50	$ —	$ —	$ 50
Other current liabilities	(51)	—	—	(51)
Total	$ (1)	$ —	$ —	$ (1)
As of December 31, 2017				
Financial Assets (Liabilities):				
Other current assets	$ 57	$ —	$ —	$ 57
Other current liabilities	(60)	—	—	(60)
Total	$ (3)	$ —	$ —	$ (3)

See Note 3 for information regarding fair value measurement of our debt instruments. See Note 13 for information regarding fair value measurement of our derivatives.

Nonrecurring Fair Value Measurements

See Note 17 regarding nonrecurring fair value measurements.

21. Asset Retirement Obligations

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

	Years Ended December 31,	
	2018	2017
	($ in millions)	
Asset retirement obligations, beginning of period	$ 177	$ 261
Additions	3	5
Revisions	11	(34)
Settlements and disposals	(35)	(70)
Accretion expense	10	15
Asset retirement obligations, end of period	166	177
Less current portion	11	15
Asset retirement obligation, long-term	$ 155	$ 162

22. Major Customers

Sales to Valero Energy Corporation constituted approximately 10% of our total revenues (before the effects of hedging for the year ended December 31, 2018. Sales to Royal Dutch Shell PLC constituted approximately 10% of our total revenues (before the effects of hedging) for the year ended December 31, 2017. Sales to BP PLC constituted approximately 10% of our total revenues (before the effects of hedging) for the years ended December 31, 2016.

23. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company, owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes and contingent convertible senior notes listed in Note 3 are fully and unconditionally guaranteed, jointly and severally, by certain of our 100% owned subsidiaries on a senior unsecured basis. Subsidiaries with noncontrolling interests, consolidated variable interest entities and certain de minimis subsidiaries are non-guarantors.

The tables below are condensed consolidating financial statements for Chesapeake Energy Corporation (parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of December 31, 2018 and 2017 and for the years ended December 31, 2018 and 2017. This financial information may not necessarily be indicative of our results of operations, cash flows or financial position had these subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2018
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 4	$ 1	$ 1	$ (2)	$ 4
Other current assets	60	1,532	2	—	1,594
Intercompany receivable, net	6,098	203	—	(6,301)	—
Total Current Assets	6,162	1,736	3	(6,303)	1,598
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties at cost, based on full cost accounting, net	598	7,302	24	—	7,924
Other property and equipment, net	—	1,091	—	—	1,091
Property and equipment held for sale, net	—	15	—	—	15
Total Property and Equipment, Net	598	8,408	24	—	9,030
LONG-TERM ASSETS:					
Other long-term assets	26	293	—	—	319
Investments in subsidiaries and intercompany advances	1,500	(97)	—	(1,403)	—
TOTAL ASSETS	$ 8,286	$ 10,340	$ 27	$ (7,706)	$ 10,947
CURRENT LIABILITIES:					
Current liabilities	$ 523	$ 2,306	$ 1	$ (2)	$ 2,828
Intercompany payable, net	25	6,276	—	(6,301)	—
Total Current Liabilities	548	8,582	1	(6,303)	2,828
LONG-TERM LIABILITIES:					
Long-term debt, net	7,341	—	—	—	7,341
Other long-term liabilities	53	258	—	—	311
Total Long-Term Liabilities	7,394	258	—	—	7,652
EQUITY:					
Chesapeake stockholders' equity	344	1,500	(97)	(1,403)	344
Noncontrolling interests	—	—	123	—	123
Total Equity	344	1,500	26	(1,403)	467
TOTAL LIABILITIES AND EQUITY	$ 8,286	$ 10,340	$ 27	$ (7,706)	$ 10,947

**CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2017
($ in millions)**

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 5	$ 1	$ 2	$ (3)	$ 5
Other current assets	154	1,364	3	(1)	1,520
Intercompany receivable, net	8,697	436	—	(9,133)	—
Total Current Assets	8,856	1,801	5	(9,137)	1,525
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties at cost, based on full cost accounting, net	435	8,888	27	—	9,350
Other property and equipment, net	—	1,314	—	—	1,314
Property and equipment held for sale, net	—	16	—	—	16
Total Property and Equipment, Net	435	10,218	27	—	10,680
LONG-TERM ASSETS:					
Other long-term assets	52	168	—	—	220
Investments in subsidiaries and intercompany advances	806	(146)	—	(660)	—
TOTAL ASSETS	$ 10,149	$ 12,041	$ 32	$ (9,797)	$ 12,425
CURRENT LIABILITIES:					
Current liabilities	$ 190	$ 2,168	$ 2	$ (4)	$ 2,356
Intercompany payable, net	433	8,648	52	(9,133)	—
Total Current Liabilities	623	10,816	54	(9,137)	2,356
LONG-TERM LIABILITIES:					
Long-term debt, net	9,921	—	—	—	9,921
Other long-term liabilities	101	419	—	—	520
Total Long-Term Liabilities	10,022	419	—	—	10,441
EQUITY:					
Chesapeake stockholders’ equity (deficit)	(496)	806	(146)	(660)	(496)
Noncontrolling interests	—	—	124	—	124
Total Equity (Deficit)	(496)	806	(22)	(660)	(372)
TOTAL LIABILITIES AND EQUITY	$ 10,149	$ 12,041	$ 32	$ (9,797)	$ 12,425

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2018
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$ —	$ 5,136	$ 19	$ —	$ 5,155
Marketing	—	5,076	—	—	5,076
Total Revenues	—	10,212	19	—	10,231
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	539	—	—	539
Oil, natural gas and NGL gathering, processing and transportation	—	1,391	7	—	1,398
Production taxes	—	123	1	—	124
Marketing	—	5,158	—	—	5,158
General and administrative	2	277	1	—	280
Restructuring and other termination costs	—	38	—	—	38
Provision for legal contingencies, net	—	26	—	—	26
Depreciation, depletion and amortization	—	1,142	3	—	1,145
Loss on sale of oil and natural gas properties	—	578	—	—	578
Impairments	—	53	—	—	53
Other operating expense	—	10	—	—	10
Total Operating Expenses	2	9,335	12	—	9,349
INCOME (LOSS) FROM OPERATIONS	(2)	877	7	—	882
OTHER INCOME (EXPENSE):					
Interest expense	(485)	(2)	—	—	(487)
Gains on investments	—	139	—	—	139
Gains on purchases or exchanges of debt	263	—	—	—	263
Other income	3	67	—	—	70
Equity in net earnings of subsidiary	1,084	3	—	(1,087)	—
Total Other Income (Expense)	865	207	—	(1,087)	(15)
INCOME BEFORE INCOME TAXES	863	1,084	7	(1,087)	867
INCOME TAX BENEFIT	(10)	—	—	—	(10)
NET INCOME	873	1,084	7	(1,087)	877
Net income attributable to noncontrolling interests	—	—	(4)	—	(4)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	873	1,084	3	(1,087)	873
Other comprehensive income	—	34	—	—	34
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$ 873	$ 1,118	$ 3	$ (1,087)	$ 907

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2017
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$ —	$ 4,962	$ 23	$ —	$ 4,985
Marketing	—	4,511	—	—	4,511
Total Revenues	—	9,473	23	—	9,496
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	562	—	—	562
Oil, natural gas and NGL gathering, processing and transportation	—	1,463	8	—	1,471
Production taxes	—	88	1	—	89
Marketing	—	4,598	—	—	4,598
General and administrative	1	259	2	—	262
Provision for legal contingencies, net	(79)	41	—	—	(38)
Depreciation, depletion and amortization	—	991	4	—	995
Impairments	—	5	—	—	5
Other operating expense	—	413	—	—	413
Total Operating Expenses	(78)	8,420	15	—	8,357
INCOME FROM OPERATIONS	78	1,053	8	—	1,139
OTHER INCOME (EXPENSE):					
Interest expense	(424)	(2)	—	—	(426)
Gains on purchases or exchanges of debt	233	—	—	—	233
Other income	1	8	—	—	9
Equity in net earnings of subsidiary	1,063	4	—	(1,067)	—
Total Other Income (Expense)	873	10	—	(1,067)	(184)
INCOME BEFORE INCOME TAXES	951	1,063	8	(1,067)	955
INCOME TAX EXPENSE	2	—	—	—	2
NET INCOME	949	1,063	8	(1,067)	953
Net income attributable to noncontrolling interests	—	—	(4)	—	(4)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	949	1,063	4	(1,067)	949
Other comprehensive income	—	39	—	—	39
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$ 949	$ 1,102	$ 4	$ (1,067)	$ 988

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2018
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$ 85	$ 1,912	$ 10	$ (7)	$ 2,000
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(1,958)	—	—	(1,958)
Acquisitions of proved and unproved properties	—	(288)	—	—	(288)
Proceeds from divestitures of proved and unproved properties	—	2,231	—	—	2,231
Additions to other property and equipment	—	(21)	—	—	(21)
Proceeds from sales of other property and equipment	—	147	—	—	147
Proceeds from sales of investments	—	74	—	—	74
Net Cash Provided by Investing Activities	—	185	—	—	185
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving credit facility borrowings	11,697	—	—	—	11,697
Payments on revolving credit facility borrowings	(12,059)	—	—	—	(12,059)
Proceeds from issuance of senior notes, net	1,236	—	—	—	1,236
Cash paid to purchase debt	(2,813)	—	—	—	(2,813)
Cash paid for preferred stock dividends	(92)	—	—	—	(92)
Other financing activities	(26)	(123)	(13)	7	(155)
Intercompany advances, net	1,971	(1,974)	2	1	—
Net Cash Used In Financing Activities	(86)	(2,097)	(11)	8	(2,186)
Net decrease in cash and cash equivalents	(1)	—	(1)	1	(1)
Cash and cash equivalents, beginning of period	5	1	2	(3)	5
Cash and cash equivalents, end of period	$ 4	$ 1	$ 1	$ (2)	$ 4

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2017
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$ 5	$ 736	$ 14	$ (10)	$ 745
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(2,186)	—	—	(2,186)
Acquisitions of proved and unproved properties	—	(285)	—	—	(285)
Proceeds from divestitures of proved and unproved properties	—	1,249	—	—	1,249
Additions to other property and equipment	—	(21)	—	—	(21)
Other investing activities	—	55	—	—	55
Net Cash Used In Investing Activities	—	(1,188)	—	—	(1,188)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving credit facility borrowings	7,771	—	—	—	7,771
Payments on revolving credit facility borrowings	(6,990)	—	—	—	(6,990)
Proceeds from issuance of senior notes, net	1,585	—	—	—	1,585
Cash paid to purchase debt	(2,592)	—	—	—	(2,592)
Cash paid for preferred stock dividends	(183)	—	—	—	(183)
Other financing activities	(39)	(5)	(13)	32	(25)
Intercompany advances, net	(456)	456	—	—	—
Net Cash Provided by (Used In) Financing Activities	(904)	451	(13)	32	(434)
Net increase (decrease) in cash and cash equivalents	(899)	(1)	1	22	(877)
Cash and cash equivalents, beginning of period	904	2	1	(25)	882
Cash and cash equivalents, end of period	$ 5	$ 1	$ 2	$ (3)	$ 5

24. Subsequent Events

On January 31, 2019, our shareholders approved a proposal to amend our restated certificate of incorporation to increase the number of authorized shares of our stock from 2,000,000,000 shares to 3,000,000,000 shares.

On February 1, 2019, we acquired WildHorse Resource Development Corporation ("WildHorse"), an oil and gas company with operations in the Eagle Ford Shale and Austin Chalk formations in southeast Texas for approximately 717.3 million shares of our common stock and $381 million in cash, and the assumption of WildHorse's debt of $1.4 billion as of February 1, 2019. We funded the cash portion of the consideration through borrowings under our revolving credit facility.

On February 1, 2019, we entered into a first amendment (the "Chesapeake facility amendment") to our Chesapeake revolving credit facility. Among other things, the Chesapeake facility amendment (i) designated Brazos Valley Longhorn and its subsidiaries as unrestricted subsidiaries under the Chesapeake revolving credit facility and (ii) expressly permitted our initial investment in WildHorse under the limitations on investments covenant. As a result of Brazos Valley Longhorn and its subsidiaries being designated as unrestricted subsidiaries under the Chesapeake revolving credit facility, transactions between Brazos Valley Longhorn and its subsidiaries, on the one hand, and Chesapeake and its subsidiaries other than Brazos Valley Longhorn, BVL Finance Corp. and the other BVL Guarantors, on the other hand, are required to be on an arm's-length basis, subject to certain exceptions, and Chesapeake is limited in the amount of investments it can make in Brazos Valley Longhorn and its subsidiaries.

On February 1, 2019, Brazos Valley Longhorn, as successor by merger to WildHorse, entered into a sixth amendment (the "WildHorse facility amendment") to the Wildhorse revolving credit facility. Among other things, the WildHorse facility amendment (i) amended the merger covenant and the definition of change of control to permit our acquisition of WildHorse and (ii) permits borrowings under the WildHorse revolving credit facility to be used to redeem or repurchase the WildHorse senior notes so long as certain conditions are met.

On February 1, 2019, Brazos Valley Longhorn, as successor by merger to WildHorse, and BVL Finance Corp., entered into a fourth supplemental indenture (the "WildHorse supplemental indenture") to the WildHorse indenture. Pursuant to the Wildhorse supplemental indenture, (i) Brazos Valley Longhorn assumed the rights and obligations of WildHorse as issuer under the WildHorse indenture and (ii) BVL Finance Corp. was named as a co-issuer of the WildHorse senior notes under the WildHorse indenture. We will account for the WildHorse acquisition by applying the acquisition method of accounting, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date.

Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2018 and 2017 are as follows:

	2018 First Quarter	2018 Second Quarter	2018 Third Quarter	2018 Fourth Quarter
	($ in millions except per share data)			
Total revenues	$ 2,489	$ 2,255	$ 2,418	$ 3,069
Income from operations	$ 278	$ 30	$ 280	$ 294
Net income (loss) attributable to Chesapeake	$ 293	$ (17)	$ 84	$ 513
Net income (loss) available to common stockholders	$ 268	$ (40)	$ 60	$ 486
Net income (loss) per common share:				
Basic	$ 0.30	$ (0.04)	$ 0.07	$ 0.53
Diluted	$ 0.29	$ (0.04)	$ 0.07	$ 0.49

	2017 First Quarter	2017 Second Quarter	2017 Third Quarter	2017 Fourth Quarter
	($ in millions except per share data)			
Total revenues	$ 2,753	$ 2,281	$ 1,943	$ 2,519
Income from operations	$ 241	$ 399	$ 94	$ 405
Net income (loss) attributable to Chesapeake	$ 140	$ 494	$ (18)	$ 333
Net income (loss) available to common stockholders	$ 75	$ 470	$ (41)	$ 309
Net income (loss) per common share:				
Basic	$ 0.08	$ 0.52	$ (0.05)	$ 0.34
Diluted	$ 0.08	$ 0.47	$ (0.05)	$ 0.33

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

Net Capitalized Costs

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

	December 31, 2018	December 31, 2017
	($ in millions)	
Oil and oil and natural gas properties:		
Proved	$ 69,642	$ 68,858
Unproved	2,337	3,484
Total	71,979	72,342
Less accumulated depreciation, depletion and amortization	(64,055)	(62,992)
Net capitalized costs	$ 7,924	$ 9,350

Unproved properties not subject to amortization as of December 31, 2018 and 2017, consisted mainly of leasehold acquired through direct purchases of significant oil and natural gas property interests. We capitalized approximately $162 million, $194 million and $242 million of interest during 2018, 2017 and 2016, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full cost pool. We will continue to evaluate our unproved properties, and although the timing of the ultimate evaluation or disposition of the properties cannot be determined, we can expect the majority of our unproved properties not held by production to be transferred into the amortization base over the next five years.

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

Costs incurred in oil and natural gas property acquisition, exploration and development activities which have been capitalized are summarized as follows:

	Years Ended December 31, 2018	2017	2016
		($ in millions)	
Acquisition of Properties:			
Proved properties	$ 80	$ 23	$ 403
Unproved properties	216	271	403
Exploratory costs	132	21	52
Development costs	2,009	2,146	1,312
Costs incurred[(a)]	$ 2,437	$ 2,461	$ 2,170

(a) Includes capitalized interest and asset retirement obligations as follows:

Capitalized interest	$ 162	$ 194	$ 242
Asset retirement obligations[(b)]	$ 8	$ (34)	$ (57)

(b) Activity in 2017 and 2016 primarily reflects revisions as the result of decreased plugging and abandonment costs in certain of our operating areas.

In 2018, we invested approximately $807 million to convert 115 mmboe of PUDs to proved developed reserves.

Results of Operations from Oil, Natural Gas and NGL Producing Activities

Our results of operations from oil, natural gas and NGL producing activities are presented below for 2018, 2017 and 2016. The following table includes revenues and expenses associated directly with our oil, natural gas and NGL producing activities. It does not include any interest costs or indirect general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil, natural gas and NGL operations.

	Years Ended December 31,		
	2018	2017	2016
		($ in millions)	
Oil, natural gas and NGL sales	$ 5,155	$ 4,985	$ 3,288
Oil, natural gas and NGL production expenses	(539)	(562)	(710)
Oil, natural gas and NGL gathering, processing and transportation expenses	(1,398)	(1,471)	(1,855)
Production taxes	(124)	(89)	(74)
Impairment of oil and natural gas properties	—	—	(2,564)
Depletion and depreciation	(1,073)	(913)	(1,003)
Imputed income tax provision[(a)]	(525)	(768)	1,027
Results of operations from oil, natural gas and NGL producing activities	$ 1,496	$ 1,182	$ (1,891)

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

Oil, Natural Gas and NGL Reserve Quantities

Our petroleum engineers and independent petroleum engineering firm estimated all of our proved reserves as of December 31, 2018, 2017 and 2016. Our independent petroleum engineering firm, Software Integrated Solutions, Division of Schlumberger Technology Corporation, estimated an aggregate of 80%, 83% and 70% of our estimated proved reserves (by volume) as of December 31, 2018, 2017 and 2016.

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

Developed oil, natural gas and NGL reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods where production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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

Presented below is a summary of changes in estimated reserves for 2018, 2017 and 2016:

	Oil	Gas	NGL	Total
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)
December 31, 2018				
Proved reserves, beginning of period	260.2	8,600	218.6	1,912
Extensions, discoveries and other additions	56.3	1,162	19.8	270
Revisions of previous estimates	(30.5)	242	5.4	15
Production	(32.7)	(832)	(18.9)	(190)
Sale of reserves-in-place	(37.8)	(2,395)	(121.6)	(559)
Purchase of reserves-in-place	—	—	—	—
Proved reserves, end of period[(a)]	215.5	6,777	103.3	1,448
Proved developed reserves:				
Beginning of period	150.9	4,980	134.9	1,116
End of period	127.6	3,314	67.9	748
Proved undeveloped reserves:				
Beginning of period	109.3	3,620	83.6	796
End of period[(b)]	87.9	3,463	35.4	700

	Oil (mmbbl)	Gas (bcf)	NGL (mmbbl)	Total (mmboe)
December 31, 2017				
Proved reserves, beginning of period	399.1	6,496	226.4	1,708
Extensions, discoveries and other additions	62.7	3,694	44.9	723
Revisions of previous estimates	(168.1)	(315)	(31.0)	(252)
Production	(32.7)	(878)	(20.9)	(200)
Sale of reserves-in-place	(0.9)	(418)	(0.8)	(71)
Purchase of reserves-in-place	0.1	21	—	4
Proved reserves, end of period[(c)]	260.2	8,600	218.6	1,912
Proved developed reserves:				
Beginning of period	200.4	5,126	134.1	1,189
End of period	150.9	4,980	134.9	1,116
Proved undeveloped reserves:				
Beginning of period	198.7	1,370	92.2	519
End of period[(b)]	109.3	3,620	83.6	796
December 31, 2016				
Proved reserves, beginning of period	313.7	6,041	183.5	1,504
Extensions, discoveries and other additions	191.2	1,798	89.0	580
Revisions of previous estimates	(58.9)	598	2.8	43
Production	(33.2)	(1,050)	(24.4)	(233)
Sale of reserves-in-place	(14.7)	(1,190)	(28.1)	(241)
Purchase of reserves-in-place	1.0	299	3.6	55
Proved reserves, end of period[(d)]	399.1	6,496	226.4	1,708
Proved developed reserves:				
Beginning of period	215.6	5,329	158.0	1,262
End of period	200.4	5,126	134.1	1,189
Proved undeveloped reserves:				
Beginning of period	98.1	712	25.5	242
End of period[(b)]	198.7	1,370	92.2	519

(a) Includes 1 mmbbl of oil, 17 bcf of natural gas and 2 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, of which 1 mmbbl of oil, 8 bcf of natural gas and 1 mmbbl of NGL are attributable to noncontrolling interest holders.

(b) As of December 31, 2018, 2017 and 2016, there were no PUDs that had remained undeveloped for five years or more.

(c) Includes 1 mmbbl of oil, 20 bcf of natural gas and 2 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, of which 1 mmbbl of oil, 10 bcf of natural gas and 1 mmbbl of NGL are attributable to the noncontrolling interest holders.

(d) Includes 1 mmbbl of oil, 23 bcf of natural gas and 2 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, of which 1 mmbbl of oil, 12 bcf of natural gas and 1 mmbbl of NGL are attributable to the noncontrolling interest holders.

During 2018, we sold 559 mmboe of proved reserves for approximately $1.8 billion primarily in the Utica and MidContinent. We recorded extensions and discoveries of 270 mmboe, primarily related to undeveloped well additions located in Marcellus and Powder River Basin operating areas. In addition, we recorded upward revisions of 28 mmboe due to higher oil, natural gas and NGL prices in 2018 partially offset by downward revisions of 13 mmboe due to ongoing portfolio evaluation including longer lateral and spacing adjustments. The oil and natural gas prices used in computing our reserves as of December 31, 2018, were $65.56 per bbl and $3.10 per mcf, respectively, before price differentials.

During 2017, we recorded extensions and discoveries of 723 mmboe primarily in the Gulf Coast, Marcellus and Utica due to longer lateral, successful drilling and additional allocated capital in our 5-year development plan. We recorded a downward revision of 327 mmboe from previous estimates due to an updated development plan in the Eagle Ford aligning up-spacing, our activity schedule and well performance. Additionally, PUDs were removed from properties in the Mid-Continent in the process of being divested. As of December 31, 2017, we did not have sufficient technical data to estimate the impact of enhanced completion techniques in Eagle Ford. The downward revision was partially offset by improved oil, natural gas and NGL prices in 2017 resulting in a 75 mmboe upward revision. The oil and natural gas prices used in computing our reserves as of December 31, 2017, were $51.34 per bbl and $2.98 per mcf, respectively, before price differentials.

During 2016, we sold 241 mmboe of proved reserves for approximately $898 million. We recorded extensions and discoveries of 580 mmboe, primarily related to undeveloped well additions located in Utica and Eagle Ford. In addition, we recorded upward revisions of 113 mmboe due to changes in previous estimates resulting from improved drilling and operating efficiencies, which includes the impact from lower operating and capital costs, partially offset by downward revisions of 70 mmboe which were primarily the result of lower oil, natural gas and NGL prices in 2016. The oil and natural gas prices used in computing our reserves as of December 31, 2016, were $42.75 per bbl and $2.49 per mcf, respectively, before price differentials.

Standardized Measure of Discounted Future Net Cash Flows

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

Future cash inflows and future production and development costs as of December 31, 2018, 2017 and 2016 were determined by applying the average of the first-day-of-the-month prices for the 12 months of the year and year-end costs to the estimated quantities of oil, natural gas and NGL to be produced. Actual future prices and costs may be materially higher or lower than the prices and costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for that year. Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

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

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

	Years Ended December 31, 2018	2017	2016
	($ in millions)		
Future cash inflows	$ 27,312 [a]	$ 26,412 [b]	$ 19,835 [c]
Future production costs	(5,946)	(7,044)	(6,800)
Future development costs	(4,032)	(4,977)	(3,621)
Future income tax provisions	(331)	—	(79)
Future net cash flows	17,003	14,391	9,335
Less effect of a 10% discount factor	(7,508)	(6,901)	(4,956)
Standardized measure of discounted future net cash flows[d]	$ 9,495	$ 7,490	$ 4,379

(a) Calculated using prices of $65.56 per bbl of oil and $3.10 per mcf of natural gas, before field differentials.

(b) Calculated using prices of $51.34 per bbl of oil and $2.98 per mcf of natural gas, before field differentials.

(c) Calculated using prices of $42.75 per bbl of oil and $2.49 per mcf of natural gas, before field differentials.

(d) Excludes discounted future net cash inflows attributable to production volumes sold to VPP buyers. See Note 14.

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

	Years Ended December 31, 2018	2017	2016
	($ in millions)		
Standardized measure, beginning of period[a]	$ 7,490	$ 4,379	$ 4,693
Sales of oil and natural gas produced, net of production costs and gathering, processing and transportation[b]	(3,128)	(2,452)	(1,227)
Net changes in prices and production costs	3,317	3,977	(1,210)
Extensions and discoveries, net of production and development costs	1,666	1,951	1,042
Changes in estimated future development costs	1,113	614	323
Previously estimated development costs incurred during the period	973	775	664
Revisions of previous quantity estimates	47	(1,255)	145
Purchase of reserves-in-place	—	3	394
Sales of reserves-in-place	(2,052)	(116)	13
Accretion of discount	749	441	473
Net change in income taxes	(32)	26	(8)
Changes in production rates and other	(648)	(853)	(923)
Standardized measure, end of period[a][c]	$ 9,495	$ 7,490	$ 4,379

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

(b) Excludes gains and losses on derivatives.

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

ITEM 9. *Changes In and Disagreements with Accountants on Accounting and Financial Disclosure*

Not applicable.

ITEM 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded as of December 31, 2018 that our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management's Report on Internal Control Over Financial Reporting is set forth in Item 8 of this Annual Report on Form 10-K.

ITEM 9B. *Other Information*

Not applicable.

PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance*

The names of executive officers and certain other senior officers of the Company and their ages, titles and biographies as of the date hereof are incorporated by reference from Item 1 of Part I of this report. The other information called for by this Item 10 is incorporated herein by reference to the definitive proxy statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2019 (the 2019 Proxy Statement).

ITEM 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the 2019 Proxy Statement.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information called for by this Item 12 is incorporated herein by reference to the 2019 Proxy Statement.

ITEM 13. *Certain Relationships and Related Transactions and Director Independence*

The information called for by this Item 13 is incorporated herein by reference to the 2019 Proxy Statement.

ITEM 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the 2019 Proxy Statement.

PART IV

ITEM 15. ***Exhibits and Financial Statement Schedules***

(a) The following financial statements, financial statement schedules and exhibits are filed as a part of this report:

1. *Financial Statements*. Chesapeake's consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules*. No financial statement schedules are applicable or required.
3. *Exhibits*. The exhibits listed below in the Index of Exhibits are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

INDEX OF EXHIBITS

		Incorporated by Reference				
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed or Furnished Herewith**
2.1	Purchase and Sale Agreement by and among certain subsidiaries of Chesapeake Energy Corporation and EAP Ohio, LLC dated July 26, 2018.	10-Q	001-13726	2.1	10/30/2018	
2.2.1*	Agreement and Plan of Merger by and among Chesapeake Energy Corporation, Coleburn Inc. and WildHorse Resource Development Corporation, dated as of October 29, 2018, as amended.	8-K	001-13726	2.1	10/30/2018	
2.2.2	Amendment No. 1 to Agreement and Plan of Merger, dated as of December 12, 2018, by and among Chesapeake Energy Corporation, Coleburn Inc. and WildHorse Resource Development Corporation.	S-4/A	333-228679	Annex A	12/19/2018	
3.1.1	Chesapeake Energy Corporation Restated Certificate of Incorporation.					X
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008	
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	8/11/2008	
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010	
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010	
3.2	Chesapeake Energy Corporation Amended and Restated Bylaws.	8-K	001-13726	3.2	6/19/2014	
4.1**	Indenture dated as of November 8, 2005 among Chesapeake Energy Corporation, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% Senior Notes due 2020.	8-K	001-13726	4.1.1	11/15/2005	

4.2.1**	Indenture dated as of August 2, 2010 among Chesapeake Energy Corporation, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee.	S-3	333-168509	4.1	8/3/2010
4.2.2	Second Supplemental Indenture, dated as of August 17, 2010 to Indenture dated as of August 2, 2010 with respect to 6.625% Senior Notes due 2020.	8-A	001-13726	4.3	9/24/2010
4.2.3	Fifth Supplemental Indenture dated February 11, 2011 to Indenture dated as of August 2, 2010 with respect to 6.125% Senior Notes due 2021.	8-A	001-13726	4.2	2/22/2011
4.2.4	Fourteenth Supplemental Indenture dated March 18, 2013 among Chesapeake Energy Corporation, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and Deutsche Bank Trust Company Americas, as Trustee, to Indenture dated as of August 2, 2010.	S-3	333-168509	4.17	3/18/2013
4.2.5	Sixteenth Supplemental Indenture dated April 1, 2013 to Indenture dated as of August 2, 2010 with respect to 5.375% Senior Notes due 2021.	8-A	001-13726	4.3	4/8/2013
4.2.6	Seventeenth Supplemental Indenture dated April 1, 2013 to Indenture dated as of August 2, 2010 with respect to 5.75% Senior Notes due 2023.	8-A	001-13726	4.4	4/8/2013
4.3.1**	Indenture dated as of April 24, 2014 by and among Chesapeake Energy Corporation, as Issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and Deutsche Bank Trust Company Americas, as Trustee.	8-K	001-13726	4.1	4/29/2014
4.3.2	First Supplemental Indenture dated as of April 24, 2014 to Indenture dated as of April 24, 2014 with respect to Floating Rate Senior Notes due 2019.	8-K	001-13726	4.2	4/29/2014
4.3.3	Second Supplemental Indenture dated as of April 24, 2014 to Indenture dated as of April 24 2014 with respect to 4.875% Senior Notes due 2022.	8-K	001-13726	4.3	4/29/2014
4.4.1	Credit Agreement dated December 15, 2014 by and among: Chesapeake Energy Corporation, as borrower; MUFG Union Bank N.A., as administrative agent, co-syndication agent, a swingline lender and a letter of credit issuer; Wells Fargo Bank and National Association, as co-syndication agent, a swingline lender and a letter of credit issuer; Bank of America, N.A., Crédit Agricole Corporate and Investment Bank and JPMorgan Chase Bank, N.A., as co-documentation agents and letter of credit issuers; and certain other lenders named therein.	10-Q	001-13726	4.1	8/14/2016

4.4.2	First Amendment to Credit Agreement dated September 30, 2015 among Chesapeake, as borrower, MUFG Union Bank N.A., as administrative agent, co-syndication agent, a swingline lender and a letter of credit issuer; Wells Fargo Bank, National Association, as co-syndication agent, a swingline lender and a letter of credit issuer; and certain other lenders named therein.	10-Q	001-13726	4.1	11/4/2015
4.4.3	Second Amendment to Credit Agreement dated December 15, 2015 among Chesapeake, as borrower, MUFG Union Bank N.A., as administrative agent, co-syndication agent, a swingline lender and a letter of credit issuer; Wells Fargo Bank, National Association, as co-syndication agent, a swingline lender and a letter of credit issuer; and certain other lenders named therein.	8-K	001-13726	10.1	12/16/2015
4.4.4††	Third Amendment to Credit Agreement dated April 8, 2016 among Chesapeake Energy Corporation, as borrower; MUFG Union Bank N.A., as administrative agent, a swingline lender and a letter of credit issuer; and certain other lenders named therein.	10-Q	001-13726	4.2	8/4/2016
4.4.5	Fourth Amendment to Credit Agreement dated May 19, 2017 among Chesapeake Energy Corporation, as borrower; MUFG Union Bank N.A., as administrative agent, a swingline lender and a letter of credit issuer; and certain other lenders named therein.	8-K	001-13726	10.1	5/22/2017
4.4.6	Amended and Restated Credit Agreement, dated as of September 12, 2018, by and among: (i) the Company, as borrower; (ii) MUFG Union Bank N.A., as the administrative agent, a swingline lender and a letter of credit issuer; (iii) Wells Fargo Bank, National Association, as co-syndication agent, a swingline lender and a letter of credit issuer; (iv) JPMorgan Chase Bank, N.A., as co-syndication agent, a swingline lender and a letter of credit issuer; and (v) certain other lenders and letter of credit issuers named therein.	8-K	001-13726	10.1	9/12/2018
4.5	Intercreditor Agreement dated as of December 23, 2015 between MUFG Bank, N.A., as Priority Lien Agent, and Deutsche Bank Trust Company Americas, as Second Lien Collateral Trustee, and acknowledged by Chesapeake and certain of its subsidiaries.	8-K	001-13726	10.1	12/23/2015
4.6	Collateral Trust Agreement, dated as of December 23, 2015, by and among Chesapeake, the guarantors named therein, and Deutsche Bank Trust Company Americas as the representative of the holders of the Second Lien Notes and as collateral trustee.	8-K	001-13726	10.2	12/23/2015
4.7	Indenture dated as of October 5, 2016, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Deutsche Bank Trust Company Americas, as trustee, with respect to the 5.5% Convertible Senior Notes due 2026.	8-K	001-13726	4.1	10/5/2016

4.8	Sixth Supplemental indenture dated as of December 20, 2016 to indenture dated as of April 24, 2014 with respect to 8.00% Senior Notes due 2025.	8-K	001-13726	4.2	12/20/2016
4.9	Registration Rights Agreement dated as of December 20, 2016, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Deutsche Bank Securities, Inc.	8-K	001-13726	4.4	12/20/2016
4.10	Purchase Agreement, dated May 22, 2017, by and among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Citigroup Global Markets Inc., as representative of the initial purchasers named therein, relating to the private placement of the 8.00% Senior Notes due 2027.	8-K	001-13726	10.1	5/23/2017
4.11	Seventh Supplemental Indenture dated as of June 6, 2017 to Indenture dated as of April 24, 2014 with respect to 8.00% Senior Notes due 2027.	8-K	001-13726	4.2	6/7/2017
4.12	Registration Rights Agreement dated as of June 6, 2017, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Citigroup Global Markets Inc.	8-K	001-13726	4.4	6/7/2017
4.13	Purchase Agreement, dated September 27, 2017, by and among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Morgan Stanley & Co. LLC, as representative of the initial purchasers named therein, relating to the private placement of the 8.00% Senior Notes due 2025 and 8.00% Senior Notes due 2027.	8-K	001-13726	10.1	9/28/2017
4.14	Registration Rights Agreement, dated as of October 12, 2017, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Morgan Stanley & Co. LLC with respect to 8.00% Senior Notes due 2025.	8-K	001-13726	4.4	10/12/2017
4.15	Registration Rights Agreement, dated as of October 12, 2017, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Morgan Stanley & Co. LLC with respect to 8.00% Senior Notes due 2027.	8-K	001-13726	4.5	10/12/2017
4.16	Eighth Supplemental Indenture, dated as of September 27, 2018 to Indenture dated as of April 24, 2014 with respect to 7.00% Senior Notes due 2024.	8-K	001-13726	4.2	9/27/2018
4.17	Ninth Supplemental Indenture, dated as of September 27, 2018 to Indenture dated as of April 24, 2014 with respect to 7.50% Senior Notes due 2026.	8-K	001-13726	4.3	9/27/2018
4.18.1	Indenture dated as of February 1, 2017 by and among WildHorse Resource Development Corporation, as Issuer, each of the guarantors party thereto, and U.S. Bank National Association, as Trustee.	8-K	001-37964	4.1	2/1/2017

4.18.2	First Supplemental Indenture, dated as of June 30, 2017, by and among WHR Eagle Ford LLC, WildHorse Resource Development Corporation, the other subsidiary guarantors named therein and U.S. Bank National Association, as Trustee.	10-Q	001-37964	4.6	8/10/2017	
4.18.3	Second Supplemental Indenture, dated as of January 8, 2018 among Burleson Sand LLC, WildHorse Resource Development Corporation, the other subsidiary guarantors named therein and U.S. Bank National Association, as Trustee.	10-K	001-37964	4.6	3/12/2018	
4.18.4	Third Supplemental Indenture, dated as of August 2, 2018 among WHCC Infrastructure, a subsidiary of WildHorse Resource Development Corporation, the other Guarantors (as defined in the Indenture referred to therein) and U.S. Bank National Association, as Trustee.	10-Q	001-37964	4.6	8/9/2018	
4.18.5	Fourth Supplemental Indenture, dated as February 1, 2019 among Brazos Valley Longhorn, L.L.C., as Successor Issuer, Brazos Valley Longhorn Finance Corp., as Co-Issuer, the Guarantors (as defined in the Indenture referred to therein) and U.S. Bank National Association, as Trustee.	8-K	001-13726	4.1	2/1/2019	
10.1.1†	Chesapeake's 2003 Stock Incentive Plan, as amended.	10-Q	001-13726	10.1.1	11/9/2009	
10.1.2†	Form of 2013 Restricted Stock Award Agreement for Chesapeake's 2003 Stock Incentive Plan.	10-K	001-13726	10.1.3	3/1/2013	
10.2.1†	Chesapeake's 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1	6/20/2013	
10.2.2†	Form of 2013 Restricted Stock Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.3	2/4/2013	
10.2.3†	Form of Nonqualified Stock Option Agreement for 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1	2/4/2013	
10.2.4†	Form of Retention Nonqualified Stock Option Agreement for 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.2	2/4/2013	
10.2.5†	Form of 2013 Non-Employee Director Restricted Stock Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-K	001-13726	10.13.7	3/1/2013	
10.2.6†	Form of 2013 Performance Share Unit Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-K	001-13726	10.13.9	3/1/2013	
10.2.7†	Form of 2014 Performance Share Unit Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-K	001-13726	10.4.7	2/27/2014	
10.2.8†	Form of Restricted Stock Unit Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-Q	001-13726	10.8	8/6/2013	
10.2.9†	Form of Non-Employee Director Restricted Stock Unit Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-Q	001-13726	10.9	8/6/2013	

10.2.10†	Form of Pension and Equity Makeup Restricted Stock Award Agreement for 2005 Amended and Restated Long Term Incentive Plan for Robert D. Lawler.	10-Q	001-13726	10.10	8/6/2013	
10.3.1†	Chesapeake Energy Corporation Deferred Amended and Restated Deferred Compensation Plan, effective January 1, 2016.	10-K	001-13726	10.3	2/25/2016	
10.3.2†	Amendment to the Chesapeake Energy Corporation Deferred Compensation Plan, effective January 1, 2019.					X
10.4.1†	Chesapeake Energy Corporation Deferred Compensation Plan for Non-Employee Directors.	10-K	001-13726	10.16	3/1/2013	
10.4.2†	Amendment to the Chesapeake Energy Corporation Deferred Compensation Plan for Non-Employee Directors, effective January 1, 2017.	10-K	001-13726	10.3.2	3/3/2017	
10.5.1†	Employment Agreement dated as of May 20, 2013 between Robert D. Lawler and Chesapeake Energy Corporation.	8-K	001-13726	10.1	5/23/2013	
10.5.2†	Amendment to Employment Agreement between Robert D. Lawler and Chesapeake Energy Corporation dated as of June 16, 2016.	8-K	001-13726	10.1	6/17/2016	
10.5.3†	Amendment to Employment Agreement between Robert D. Lawler and Chesapeake Energy Corporation dated as of December 31, 2018.	8-K	001-13726	10.1	1/4/2019	
10.5.4†	Pension Makeup Restricted Stock Award Agreement for Robert D. Lawler, dated June 17, 2018.	10-Q	001-13726	10.1	8/1/2018	
10.6†	Employment Agreement dated as of January 1, 2019 between Domenic J. Dell'Osso, Jr. and Chesapeake Energy Corporation.	8-K	001-13726	10.2	1/4/2019	
10.7†	Employment Agreement dated as of January 1, 2019 between James R. Webb and Chesapeake Energy Corporation.	8-K	001-13726	10.3	1/4/2019	
10.8†	Employment Agreement dated as of January 1, 2019 between Frank J. Patterson and Chesapeake Energy Corporation.	8-K	001-13726	10.4	1/4/2019	
10.9†	Employment Agreement dated as of January 1, 2019 between M. Jason Pigott and Chesapeake Energy Corporation.	8-K	001-13726	10.5	1/4/2019	
10.10†	Employment Agreement dated as of January 1, 2019 between Chesapeake Energy Corporation and William M. Buergler.					X
10.11†	Form of Employment Agreement dated as of January 1, 2019 between Executive Vice President/Senior Vice President and Chesapeake Energy Corporation.					X
10.12†	Form of Indemnity Agreement for officers and directors of Chesapeake Energy Corporation and its subsidiaries.	8-K	001-13726	10.3	6/27/2012	
10.13†	Chesapeake Energy Corporation 2013 Annual Incentive Plan.	DEF 14A	001-13726	Exhibit G	5/3/2013	

10.13.1†	Chesapeake Energy Corporation Restated 2014 Long Term Incentive Plan.	10-Q	001-13726	10.1	8/3/2017
10.13.2†	Form of Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.2	8/6/2014
10.13.3†	Form of Restricted Stock Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.3	8/6/2014
10.13.4†	Form of Nonqualified Stock Option Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.4	8/6/2014
10.13.5†	Form of Performance Share Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.5	8/6/2014
10.13.6†	Form of Director Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.6	8/6/2014
10.14.1	Voting and Support Agreement, by and among Jay Carlton Graham, Esquisto Holdings, LLC, WHE AcqCo Holdings, LLC, WHR Holdings, LLC, NGP XI US Holdings, L.P., Chesapeake Energy Corporation and WildHorse Resource Development Corporation, dated as of October 29, 2018.	8-K	001-13726	10.1	10/30/2018
10.14.2	Voting and Support Agreement, by and among CP VI Eagle Holdings, L.P., Chesapeake Energy Corporation and WildHorse Resource Development Corporation, dated as of October 29, 2018.	8-K	001-13726	10.2	10/30/2018
10.14.3	Registration Rights Agreement, by and among Esquisto Holdings, LLC, WHE AcqCo Holdings, LLC, WHR Holdings, LLC, NGP XI US Holdings, L.P., CP VI Eagle Holdings, L.P. and Chesapeake Energy Corporation, dated as of October 29, 2018.	8-K	001-13726	10.3	10/30/2018
10.15.1	Credit Agreement, dated December 19, 2016, by and among WildHorse Resource Development Corporation, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, BMO Harris Bank, N.A., as Syndication Agent, the Lenders party thereto and the other parties party thereto.	8-K	001-37964	10.3	12/22/2016
10.15.2	First Amendment to Credit Agreement, dated as of April 4, 2017, by and among WildHorse Resource Development Corporation, each of the guarantors party thereto, and Wells Fargo Bank, National Association, as Administrative Agent for the Lenders party thereto, BMO Harris Bank, N.A., as Syndication Agent, the Lenders party thereto and the other parties party thereto.	10-Q	001-37964	10.1	5/15/2017
10.15.3	Second Amendment to Credit Agreement, dated as of June 30, 2017, by and among WildHorse Resource Development Corporation, each of the guarantors party thereto, and Wells Fargo Bank, National Association, as Administrative Agent for the Lenders party thereto, BMO Harris Bank, N.A., as Syndication Agent, the Lenders party thereto and the other parties party thereto.	8-K	001-37964	10.1	7/7/2017

10.15.4	Third Amendment to Credit Agreement, dated as of October 4, 2017, by and among WildHorse Resource Development Corporation, each of the guarantors party thereto, and Wells Fargo Bank, National Association, as Administrative Agent for the Lenders party thereto, BMO Harris Bank, N.A., as Syndication Agent, the Lenders party thereto and the other parties party thereto.	8-K	001-37964	10.1	10/5/2017	
10.15.5	Fourth Amendment to Credit Agreement, dated as of March 23, 2018 by and among WildHorse Resource Development Corporation, each of the guarantors party thereto, and Wells Fargo Bank, National Association, as Administrative Agent for the Lenders party thereto, BMO Harris Bank, N.A., as Syndication Agent, the Lenders party thereto and the other parties party thereto.	8-K	001-37964	10.1	3/27/2018	
10.15.6	Fifth Amendment to Credit Agreement, dated as of October 15, 2018 by and among WildHorse Resource Development Corporation, each of the guarantors party thereto, and Wells Fargo Bank, National Association, as Administrative Agent for the Lenders party thereto, BMO Harris Bank, N.A., as Syndication Agent, the Lenders party thereto and the other parties party thereto.	10-Q	001-37964	10.1	11/8/2018	
10.15.7	Sixth Amendment to Credit Agreement, dated as of February 1, 2019, by and among Brazos Valley Longhorn, L.L.C. (as successor by merger to WildHorse Resource Development Corporation), each of each of the guarantors party thereto, and Wells Fargo Bank, National Association, as Administrative Agent for the Lenders party thereto, BMO Harris Bank, N.A., as Syndication Agent, the Lenders party thereto and the other parties party thereto.	8-K	001-13726	10.1	2/1/2019	
21	Subsidiaries of Chesapeake Energy Corporation.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of Software Integrated Solutions, Division of Schlumberger Technology Corporation.					X
31.1	Robert D. Lawler, President and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Robert D. Lawler, President and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X

99	Report of Software Integrated Solutions, Division of Schlumberger Technology Corporation.	X
101 INS	XBRL Instance Document.	X
101 SCH	XBRL Taxonomy Extension Schema Document.	X
101 CAL	XBRL Taxonomy Extension Calculation Linkbase Document.	X
101 DEF	XBRL Taxonomy Extension Definition Linkbase Document.	X
101 LAB	XBRL Taxonomy Extension Labels Linkbase Document.	X
101 PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	X

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* Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The registrant hereby undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

** The Company agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities and Exchange Commission upon request.

† Management contract or compensatory plan or arrangement.

†† Confidential treatment has been requested for portions of this exhibit. These portions have been omitted and submitted separately to the Securities and Exchange Commission.

PLEASE NOTE: Pursuant to the rules and regulations of the Securities and Exchange Commission, we have filed or incorporated by reference the agreements referenced above as exhibits to this Annual Report on Form 10-K. The agreements have been filed to provide investors with information regarding their respective terms. The agreements are not intended to provide any other factual information about Chesapeake Energy Corporation or its business or operations. In particular, the assertions embodied in any representations, warranties and covenants contained in the agreements may be subject to qualifications with respect to knowledge and materiality different from those applicable to investors and may be qualified by information in confidential disclosure schedules not included with the exhibits. These disclosure schedules may contain information that modifies, qualifies and creates exceptions to the representations, warranties and covenants set forth in the agreements. Moreover, certain representations, warranties and covenants in the agreements may have been used for the purpose of allocating risk between the parties, rather than establishing matters as facts. In addition, information concerning the subject matter of the representations, warranties and covenants may have changed after the date of the respective agreement, which subsequent information may or may not be fully reflected in our public disclosures. Accordingly, investors should not rely on the representations, warranties and covenants in the agreements as characterizations of the actual state of facts about Chesapeake Energy Corporation or its business or operations on the date hereof.

ITEM 16. *Form 10-K Summary*

Not applicable.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE ENERGY CORPORATION

Date: February 27, 2019

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

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Robert D. Lawler and Domenic J. Dell'Osso, Jr., and each of them, either one of whom may act without joinder of the other, his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all amendments to this Annual Report on Form 10-K, and to file the same, with all, exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each, and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, and each of them, or the substitute or substitutes of any or all of them, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ ROBERT D. LAWLER **Robert D. Lawler**	President and Chief Executive Officer (Principal Executive Officer)	February 27, 2019
/s/ DOMENIC J. DELL'OSSO, JR. **Domenic J. Dell'Osso, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2019
/s/ WILLIAM M. BUERGLER **William M. Buergler**	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2019
/s/ R. BRAD MARTIN **R. Brad Martin**	Chairman of the Board	February 27, 2019
/s/ ARCHIE W. DUNHAM **Archie W. Dunham**	Director and Chairman Emeritus	February 27, 2019
/s/ GLORIA R. BOYLAND **Gloria R. Boyland**	Director	February 27, 2019
/s/ LUKE R. CORBETT **Luke R. Corbett**	Director	February 27, 2019
/s/ MARK A. EDMUNDS **Mark A. Edmunds**	Director	February 27, 2019
/s/ DAVID W. HAYES **David W. Hayes**	Director	February 27, 2019
/s/ LESLIE S. KEATING **Leslie S. Keating**	Director	February 27, 2019
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	February 27, 2019
/s/ THOMAS L. RYAN **Thomas L. Ryan**	Director	February 27, 2019

Company Information

BOARD OF DIRECTORS

R. Brad Martin (1,2)
Chairman of the Board
Chairman
RBM Venture Company
Retired Chairman and Chief Executive Officer
Saks Incorporated

Archie W. Dunham (1,4)
Retiring in May 2019
Chairman Emeritus
Former Executive Chairman
ConocoPhillips

Gloria R. Boyland (1,3)
Corporate Vice President of Operations
and Service Support
FedEx Corporation

Luke R. Corbett (1,3,4)
Manager
Corbett Management LLC
Retired Chairman and Chief Executive Officer
Kerr-McGee Corporation

Mark A. Edmunds (3,4)
Vice Chairman and Partner
Deloitte LLP

Scott A. Gieselman
Nominated for election in May 2019
Partner
NGP Energy Capital Management, L.L.C.

David W. Hayes (3,4)
Partner
NGP Energy Capital Management, L.L.C.

Leslie Starr Keating (3,4)
Retired Executive Vice President,
Supply Chain Strategy and Transformation
Advance Auto Parts, Inc.

Robert D. ("Doug") Lawler
President and Chief Executive Officer
Chesapeake Energy Corporation

Merrill A. ("Pete") Miller, Jr. (2,4)
Retired Executive Chairman
NOW Inc.

Thomas L. Ryan (2,3)
Chairman and Chief Executive Officer
Service Corporation International

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

MANAGEMENT TEAM

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

Domenic J. ("Nick") Dell'Osso, Jr.
Executive Vice President
and Chief Financial Officer

Frank J. Patterson
Executive Vice President –
Exploration and Production

M. Jason Pigott
Executive Vice President –
Operations and Technical Services

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

William M. Buergler
Senior Vice President
and Chief Accounting Officer

INVESTOR INFORMATION

Company financial information, public disclosures and other information are available through Chesapeake's website at www.chk.com. We will promptly deliver free of charge, upon request, a copy of the annual report on Form 10-K to any shareholder requesting a copy. Requests should be directed to Investor Relations at our corporate headquarters address.

COMMON STOCK

Chesapeake Energy Corporation's common stock is listed on the New York Stock Exchange (NYSE) under the symbol CHK. As of March 18, 2019, the record date for our 2019 Annual Meeting of Shareholders, there were approximately 310,000 beneficial owners of our common stock.

INDEPENDENT PUBLIC ACCOUNTANTS

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

STOCK TRANSFER AGENT AND REGISTRAR

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to our transfer agent:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021
(800) 884-4225
www.computershare.com

TRUSTEE FOR THE COMPANY'S SENIOR NOTES

Issued prior to 2013
The Bank of New York
Mellon Trust Company, N.A.
101 Barclay Street, 8th Floor
New York, NY 10286
www.bnymellon.com

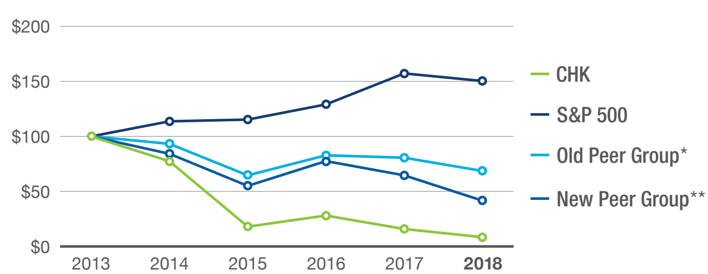
Issued in 2013 – 2019
Deutsche Bank Trust
Company Americas
60 Wall Street, 37th Floor
New York, NY 10005
www.db.com

FORWARD-LOOKING STATEMENTS

The letter to shareholders includes "forward-looking statements" related to our business strategy and objectives for future operations. Although we believe there is a reasonable basis for these forward-looking statements, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1A of our 2018 Annual Report on Form 10-K included in this report. We caution you not to place undue reliance on forward-looking statements, and we undertake no obligation to update this information, except as required by law. We urge you to carefully review and consider the disclosures made in our Form 10-K and our other filings with the Securities and Exchange Commission regarding the risks and factors that may affect our business.

CHESAPEAKE'S FIVE-YEAR COMMON STOCK PERFORMANCE

The graph assumes an investment of $100 on December 31, 2013 and the reinvestment of all dividends. Source: Zacks Investment Research, Inc.



* Anadarko Petroleum Corporation, Apache Corporation, ConocoPhillips, Devon Energy Corporation, Encana Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc. and Occidental Petroleum Corporation

** Anadarko Petroleum Corporation, Antero Resources Corporation, Apache Corporation, Cimarex Energy Co., Devon Energy Corporation, Encana Corporation, EQT Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Company and Range Resources Corporation

CHESAPEAKE ENERGY

6100 NORTH WESTERN AVENUE
OKLAHOMA CITY, OK 73118

chk.com