UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2019

☐ **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	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, par value $0.01	CHK	New York Stock Exchange
6.625% Senior Notes due 2020	CHK20A	New York Stock Exchange
6.875% Senior Notes due 2020	CHK20	New York Stock Exchange
6.125% Senior Notes due 2021	CHK21	New York Stock Exchange
5.375% Senior Notes due 2021	CHK21A	New York Stock Exchange
4.875% Senior Notes due 2022	CHK22	New York Stock Exchange
5.75% Senior Notes due 2023	CHK23	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	CHK Pr D	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act. Yes ☐ No ☒

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 ☒ 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 ☒ No ☐

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 ☒ 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 ☒

The aggregate market value of our common stock held by non-affiliates on June 28, 2019, was approximately $2.2 billion. As of February 19, 2020, there were 1,954,583,780 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2020 Annual Meeting of Shareholders are incorporated by reference in Part III.

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.

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., “Brazos Valley Longhorn” or “BVL” 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, including matters relating to our ability to meet debt service requirement, cost-cutting measures, reductions in expenditures, refinancing transactions, capital exchange transactions, asset divestitures, reductions in capital expenditures, operational efficiencies, cost savings due to operational and capital efficiencies related to the WildHorse Merger and the other items discussed in the Introduction to Item 7 of Part II of this report. 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:

- our ability to comply with the covenants under our revolving credit facility and other indebtedness;
- the volatility of oil, natural gas and NGL prices, which are affected by general economic and business conditions, as well as increased demand for (and availability of) alternative fuels and electric vehicles;
- 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;
- legislative and regulatory initiatives addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal;
- 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 and cost savings;
- 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 13,500 oil and natural gas wells. We have significant 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 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 717.4 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 EBITDAX ratio.

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. We continue to focus on reducing debt, increasing cash provided by operating activities, improving margins through financial discipline and operating efficiencies and maintaining exceptional environmental and safety performance. To accomplish these goals, we intend to allocate our capital expenditures to projects we believe offer the highest return and value 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 per barrel of oil equivalent production (production, gathering, processing and transportation and general and administrative) through operational efficiencies, including improving our production volumes from existing wells.

We believe that our dedication to financial discipline, the flexibility and efficiency of our capital program 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, 2019, we held an interest in approximately 13,500 gross (6,800 net) productive wells, including 11,400 properties in which we held a working interest and 2,100 properties in which we held an overriding or royalty interest. Of the 11,400 properties in which we had a working interest, we operated 8,500 wells, of which 7,000 gross (4,000 net), were classified as productive natural gas wells and 4,400 gross (2,800 net) were classified as productive oil wells. During 2019, we drilled or participated in 370 gross (273 net) wells as operator and participated in another 49 gross (3 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:

	2019				2018				2017			
	Gross	**%**	**Net**	**%**	**Gross**	**%**	**Net**	**%**	**Gross**	**%**	**Net**	**%**
Development:												
Productive	414	100	271	100	363	99	227	99	462	99	292	99
Dry	—	—	—	—	2	1	1	1	4	1	2	1
Total	414	100	271	100	365	100	228	100	466	100	294	100
Exploratory:												
Productive	1	20	1	20	10	83	9	82	2	100	2	100
Dry	4	80	4	80	2	17	2	18	—	—	—	—
Total	5	100	5	100	12	100	11	100	2	100	2	100

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

	2019		2018		2017	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Marcellus	44	22	52	23	43	21
Haynesville	22	16	30	21	37	34
Eagle Ford	150	85	162	98	180	106
Brazos Valley	83	79	—	—	—	—
Powder River Basin	75	57	41	34	25	21
Mid-Continent	40	12	52	32	114	58
Utica	—	—	40	31	69	56
Other	5	5	—	—	—	—
Total	419	276	377	239	468	296

As of December 31, 2019, we had 123 gross (70 net) wells in the process of being drilled or completed.

Production Volumes, Sales Prices, Production Expenses 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,		
	2019	2018	2017
Net Production:			
Oil (mmbbl)	43	33	33
Natural gas (bcf)	728	832	878
NGL (mmbbl)	12	19	21
Oil equivalent (mmboe)	177	190	200
Average Sales Price of Production:			
Oil ($ per bbl)	$ 59.16	$ 67.25	$ 51.03
Natural gas ($ per mcf)	$ 2.45	$ 2.99	$ 2.76
NGL ($ per bbl)	$ 15.62	$ 26.50	$ 23.18
Oil equivalent ($ per boe)	$ 25.57	$ 27.27	$ 22.88
Average Sales Price (including realized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 60.00	$ 57.42	$ 53.19
Natural gas ($ per mcf)	$ 2.60	$ 3.00	$ 2.75
NGL ($ per bbl)	$ 15.62	$ 25.84	$ 22.98
Oil equivalent ($ per boe)	$ 26.42	$ 25.56	$ 23.17
Expenses ($ per boe):			
Oil, natural gas and NGL production	$ 2.94	$ 2.50	$ 2.59
Oil, natural gas and NGL gathering, processing and transportation	$ 6.13	$ 7.35	$ 7.36

Oil, Natural Gas and NGL Reserves

The tables below set forth information as of December 31, 2019, 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, 2019			
	Oil (mmbbl)	Natural Gas (bcf)	NGL (mmbbl)	Total (mmboe)
Proved developed	201	3,377	82	846
Proved undeveloped	157	3,189	38	726
Total proved[(a)]	358	6,566	120	1,572

	Proved Developed	Proved Undeveloped	Total Proved
	($ in millions)		
Estimated future net revenue[(b)]	$ 10,488	$ 6,656	$ 17,144
Present value of estimated future net revenue (PV-10)[(b)]	$ 6,341	$ 2,674	$ 9,015
Standardized measure[(b)]			$ 9,000

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(a) Marcellus, Eagle Ford, Haynesville and Brazos Valley accounted for approximately 42%, 19%, 18%, and 14% respectively, of our estimated proved reserves by volume as of December 31, 2019.

(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 pricing differentials and costs under existing economic conditions as of December 31, 2019, 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, 2019. The prices used in our PV-10 measure were $55.69 of oil and $2.58 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, 2019. 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 $15 million as of December 31, 2019.

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 comparison 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, 2019, our proved reserve estimates included 726 mmboe of reserves classified as proved undeveloped, compared to 700 mmboe as of December 31, 2018. Presented below is a summary of changes in our proved undeveloped reserves (PUDs) for 2019:

	Total (mmboe)
Proved undeveloped reserves, beginning of period	700
Extensions and discoveries	185
Revisions of previous estimates	(128)
Developed	(167)
Purchase of reserves-in-place	136
Proved undeveloped reserves, end of period	726

As of December 31, 2019, all PUDs were planned to be developed within five years of original recording. In 2019, we invested approximately $1.2 billion to convert 167 mmboe of PUDs to proved developed reserves. In 2020, we estimate that we will invest approximately $1.4 billion for PUD conversion. We added 185 mmboe of proved undeveloped reserves through extensions and discoveries primarily due to an updated five-year development plan. We recorded a downward revision of 128 mmboe from previous estimates due to lateral length adjustments, performance, updates to our five-year development plan and changes in commodity prices.

The future net revenue attributable to our estimated PUDs was $6.7 billion and the present value was $2.7 billion as of December 31, 2019. These values were calculated assuming that we will expend approximately $5 billion to develop these reserves ($1.4 billion in 2020, $1.3 billion in 2021, $1.0 billion in 2022, $744 million in 2023 and $566 million in 2024). 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 846 mmboe of proved developed reserves as of December 31, 2019, approximately 13 mmboe, or 2%, 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, 2019, 2018 and 2017, 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 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 this report for further discussion of our reserve quantities.

Reserves Estimation

Our Corporate Reserves Department prepared approximately 19% by volume, and approximately 15% 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 17 years of practical experience in the oil and gas industry, with approximately 15 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 81% by volume, and approximately 85% by value, of our estimated proved reserves as of December 31, 2019. 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.

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, 2019. 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	547	350	253	172	16	16	816	538
Haynesville	293	263	36	29	1	1	330	293
Eagle Ford	310	186	68	46	—	—	378	232
Brazos Valley	411	321	302	156	—	—	713	477
Powder River Basin	96	77	166	128	1	1	263	206
Mid-Continent	900	582	211	138	17	16	1,128	736
Other[(a)]	167	132	967	912	431	427	1,565	1,471
Total	2,724	1,911	2,003	1,581	466	461	5,193	3,953

(a) Includes 1.3 million net acres retained in the 2016 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, 2019:

	Acres Expiring	
	Gross Acres	Net Acres
	(in thousands)	
Years Ending December 31:		
2020	83	79
2021	62	54
2022	28	28
After 2022	88	86
Held-by-production[(a)]	1,742	1,334
Total	2,003	1,581

(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 6 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 12% and 10% of total revenues (before the effects of hedging) for the years ended December 31, 2019 and 2018, respectively. Sales to Royal Dutch Shell PLC constituted approximately 10% of total revenues (before the effects of hedging) for the year ended December 31, 2017. No other purchasers accounted for more than 10% of our total revenues in 2019, 2018 or 2017.

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 that 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.

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/data;
- hydraulic fracturing;
- 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 well completion and hydraulic fracturing;
- water withdrawal;
- well production and operations, including processing and gathering systems;
- emergency response, contingency plans and spill prevention plans;
- emissions and discharges permitting;
- 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, administrative, civil or criminal fines or penalties or 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 safety and health compliance 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 the protection of the environment and safety and health compliance 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.

Our operations also are 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, while 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. For further discussion, see Item *1A. Risk Factors - We are subject to extensive governmental regulation, which can change and could adversely impact our business.*

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 make it difficult or impossible to conduct our operations, and thereby reduce the amount of oil, natural gas and NGL that we are ultimately able to produce 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.

For further discussion, see Item *1A. Risk Factors - Oil and natural gas drilling and producing operations can be hazardous and may expose us to liabilities.*

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 $50 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, 53, 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., 43, 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, 61, 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.

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

James R. Webb, 52, 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, 47, 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 2,300 employees as of December 31, 2019.

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 a reduction of the carrying value of our oil and natural gas properties due to recognizing impairments in proved and unproved 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, 2019, 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 19, 2020, the NYMEX WTI oil price was $53.29 per bbl and the NYMEX Henry Hub natural gas price was $1.99 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, including impacts from global or national health epidemics and concerns, such as the recent coronavirus;
- 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 and others to agree to and maintain oil price and production controls;
- increased use of competing energy products, including alternative energy sources;
- 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. As of February 19, 2020, including January and February derivative contracts that have settled, approximately 70% of our 2020 forecasted oil, natural gas and NGL production revenue was hedged. We had approximately 76% downside oil price protection through swaps and collars at an average price of $59.90 per bbl. We had 39% downside gas price protection through swaps at $2.76 per mcf and 14% under put spread arrangements based on an average bought put NYMEX price of $2.05 per mcf and exposure below an average sold put NYMEX price of $1.80 per mcf. Even with oil, natural gas and NGL derivatives currently in place to mitigate price risks associated with a portion of our 2020 cash flows, we have substantial exposure to oil, natural gas and NGL prices in 2020 and 2021 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, 2019, we had approximately $8.916 billion in principal amount of debt outstanding (including $301 million of current maturities and $1.590 billion drawn under our senior secured revolving credit facility). As of December 31, 2019, we had approximately $59 million of letters of credit issued and borrowing capacity of approximately $1.351 billion under our $3.0 billion senior secured revolving credit facility. See Note 5 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, 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 $3.0 billion credit facility for liquidity, and the borrowing base is subject to a redetermination in the second quarter of 2020. If our borrowing base under our revolving credit facility decreases 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 our credit facility declines as a result of lower oil and natural gas prices, asset dispositions or otherwise, we may be required to pledge additional collateral 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, including by curtailing our drilling program; 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 facility and term loan facility bear interest at a variable rate and expose us to interest rate risk. As of December 31, 2019, we had $3.1 billion 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 facility requires us to maintain compliance with specified financial ratios and satisfy certain financial condition tests, including a leverage ratio as of the end of each fiscal quarter of not greater than 4.50 to1 through the fiscal quarter ending December 31, 2021, with step-downs to 4.25 to 1 for the fiscal quarter ending March 31, 2022 and to 4.00 to 1 for each fiscal quarter ending thereafter, a first lien secured leverage ratio of not greater than 2.50 to 1 as of the end of each fiscal quarter, and a fixed charge coverage ratio of not less than 2.00 to 1 as of the end of the fiscal quarter ending December 31, 2019, 2.25 to 1 as of the end of each fiscal quarter ending March 31 and June 30, 2020, and 2.50 to 1 as of the end of each fiscal quarter ending September 30, 2020 and thereafter. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a continued downturn in our business or a downturn in the economy in general or otherwise conduct necessary corporate activities. Further declines in oil, NGL and natural gas prices, or a prolonged period of low oil, NGL and natural gas prices could eventually result in our failing to meet one or more of the financial covenants under our credit facility, 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.

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 facility that, if not cured or waived, could result in acceleration of all indebtedness outstanding thereunder and cross-default rights under our other debt. If that should occur, we may be unable to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. In addition, in the event of an event of default under the credit facility or other indebtedness, the affected lenders could foreclose on the collateral securing the credit facility and require repayment of all borrowings outstanding thereunder. If the amounts outstanding under the credit facility 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.

If we cannot meet the continued listing requirements of the NYSE, the NYSE may delist our common stock, which would have an adverse impact on the trading volume, liquidity and market price of our common stock and allow holders of our convertible senior notes to require us to repurchase their notes.

On December 10, 2019, we were notified by the New York Stock Exchange (the "NYSE") that the average closing price of our common stock, $0.01 par value per share (the "Common Stock"), over a prior 30 consecutive trading day period was below $1.00 per share, which is the minimum average closing price per share required to maintain listing on the NYSE under Section 802.01C of the NYSE Listed Company Manual. We have a period of six months following the receipt of the notice to regain compliance with the minimum share price requirement, with the possibility of extension at the discretion of the NYSE. In order to regain compliance, on the last trading day in any calendar month during the cure period, the Common Stock must have: (i) a closing price of at least $1.00 per share; and (ii) an average closing price of at least $1.00 per share over the 30 trading day period ending on the last trading day of such month. If we fail to regain compliance with Section 802.01C of the NYSE Listed Company Manual by the end of the cure period, the Common Stock will be subject to the NYSE's suspension and delisting procedures. To regain compliance with NYSE listing standards we intend to implement a reverse stock split, subject to approval of our board of directors and shareholders.

If the Common Stock ultimately were to be delisted for any reason, it could negatively impact us as it would likely reduce the liquidity and market price of the Common Stock; reduce the number of investors willing to hold or acquire the Common Stock; and negatively impact our ability to access equity markets and obtain financing. If the Common Stock were to be removed from listing on the NYSE (and the Common Stock were not to become listed on other specified stock exchanges), holders of our convertible senior notes would have a right to require us to repurchase their notes. As of December 31, 2019, there was $1.06 billion aggregate principal amount of convertible senior notes outstanding, and there can be no assurance we would be able to repurchase such notes if required to do so in connection with a delisting.

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 24, 2020, we have posted approximately $60 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 $220 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 facility, and negatively impact our liquidity.

If commodity prices remain depressed or drilling efforts are unsuccessful, we may be required to record write downs of the carrying value of our oil and natural gas properties.

We have been required to write down the carrying value of certain of our oil and natural gas properties in the past and there is a risk that we will be required to take additional writedowns in the future. Writedowns may occur in the future when oil and natural gas prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, or due to the anticipated sale of properties.

The successful efforts method of accounting requires that we periodically review the carrying value of our oil and natural gas properties for possible impairment. Impairment is recognized for the excess of book value over fair value when the book value of a proven property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on oil and natural gas prices at the time of the impairment review, or as a result of continuing evaluation of drilling results, production data, economics, divestiture activity, and other factors. A writedown constitutes a non-cash charge to earnings and does not impact cash or cash flows from operating activities; however, it reflects our long-term ability to recover an investment, reduces our reported earnings and increases certain leverage ratios. 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 facility. 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 2020 capital expenditures, inclusive of capitalized interest, are $1.3 - $1.6 billion compared to our 2019 capital spending level of $2.2 billion. Management continues to review operational plans for 2020 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, 2019, approximately 46% 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 $5 billion during the next five years ending in 2024. 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, 2019 present value is based on a $55.69 per bbl of oil price and a $2.58 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.

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.

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 our senior secured revolving credit facility. 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 reduce 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 2020 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 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. 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, such as the January 30, 2020 well control incident at a wellsite located in Burleson County, Texas, causing the deaths of three of our contractors' employees and injuring a fourth;
- 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 opinion.

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.

Moreover, certain of these events could result in environmental pollution and impact to third parties, including persons living in proximity to our operations, our employees and employees of our contractors, leading to possible injuries, death or significant damage to property and natural resources.

We are subject to extensive governmental regulation, which can change and 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 developments could, among other things, restrict production levels, impose price controls, change 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, 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. This is particularly true of changes related to pipeline safety, seismic activity and climate change, as discussed below.

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 for 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." In October 2019, PHMSA issued three new final rules, that, among other things, extend certain requirements for integrity assessments and leak detections beyond high consequence areas. 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.

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. 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.

Seismic Activity. Earthquakes in some of our operating areas and elsewhere have prompted concerns about seismic activity. 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.

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 the 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, in September 2018, BLM published a final rule to repeal certain requirements of these regulations. Similarly, in September 2019, EPA published a rule proposing to reconsider certain aspects of its regulations for the control of methane emissions. Nevertheless, several states where we operate, including Wyoming, 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 renewable energy standards and/or cap-and-trade and/or carbon tax programs. A cap-and-trade program generally would cap overall greenhouse gas emissions on an economy- wide basis and require major sources of greenhouse gas emissions or major fuel producers to acquire and surrender emission allowances. 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 an increasing number of financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this would make it more difficult and expensive 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.

Conservation measures and technological advances could reduce demand for natural gas and oil.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to natural gas and oil, technological advances in fuel economy and energy generation devices could reduce demand for natural gas and oil. The impact of the changing demand for natural gas and oil could adversely impact our earnings, cash flows and financial position.

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.

Development activities, particularly hydraulic fracturing, require the use and disposal of significant quantities of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. The imposition of new environmental initiatives and regulations, such as the OCC's volume reduction plans for oil and natural gas disposal wells injecting wastewater into the Arbuckle formation and the EPA's June 2016 pretreatment standards for wastewater, could further restrict our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of oil and natural gas.

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 failure to comply with environmental laws and regulations can result in the imposition of administrative, civil 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 or our industry could have an adverse effect on our operations.

Negative public perception regarding us 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. The 2020 presidential and congressional elections may result in a change in administration and control of Congress with the potential consequence of increased restrictions on oil and gas production activities, which could materially adversely affect our industry and our financial condition and results of operations.

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 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. For example, the California Consumer Privacy Act ("CCPA") was signed into law on June 28, 2018 and largely took effect on January 1, 2020. The CCPA, among other things, contains new disclosure obligations for businesses that collect personal information about California residents and enhanced consumer protections for those individuals, and provides for statutory fines for data security breaches or other CCPA violations. Meanwhile, over fifteen other states have considered privacy laws like the CCPA.

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 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 facility, term loan facility, 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 facility and to offer to purchase our term loan 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.

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 achieved $250 million of cost savings in 2019 and 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.

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 net operating loss (NOL) carryforwards, disallowed business interest carryforwards and possibly other tax attributes 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 attributes may be subject to an annual limitation under Section 382 of the Code should transactions involving our equity, including issuances of our stock or the sale or exchange of our stock by certain shareholders, result in a cumulative shift of more than 50% in the beneficial ownership of our stock during any three-year testing period (an "Ownership Change"). The annual 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 by recognized built-in gains occurring within a five-year period following the Ownership Change, but only to the extent of the net unrealized built-in gain which existed at the time of the Ownership Change. However, proposed regulations issued on September 10, 2019, and on January 14, 2020, under Section 382(h) of the Code (the "Proposed Regulations") would, if finalized in their current form, limit the potential increases to the annual limitation amount for certain built-in gains existing at the time of an Ownership Change, (unless the transition relief provisions of the Proposed Regulations are applicable), thereby significantly reducing the ability to utilize tax attributes. 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 NOL carryforwards and disallowed business interest carryforwards, such as depreciable basis of tangible equipment. Some states impose similar limitations on tax attribute utilization upon experiencing an Ownership Change.

We believe that based on information currently available neither the WildHorse Merger, the exchanges of our common stock for certain outstanding senior notes that occurred during 2019 nor the exchange of our common stock for certain Cumulative Convertible Preferred Stock that also occurred during 2019 resulted in an Ownership Change. Therefore, with the exception of the NOL carryforwards and disallowed business interest carryforwards acquired upon the WildHorse Merger, we do not believe we have a limitation on the ability to utilize our carryforwards and other tax attributes under Section 382 of the Code as of December 31, 2019. However, issuances, sales or exchanges of our stock (including, potentially, relatively small transactions and transactions beyond our control) occurring after December 31, 2019, taken together with other prior transactions with respect to our stock, could trigger an Ownership Change and therefore a limitation on our ability to utilize our carryforwards and other tax attributes. Furthermore, if such an Ownership Change were to occur and the Proposed Regulations are finalized in their current form, the severity of the limitation may worsen due to the inability to consider certain recognized built-in gains in the calculation of the annual limitation amount. Any such limitation could result in a significant portion of our NOL carryforwards expiring before we would be able to utilize them to reduce taxable income in future periods. Based on the foregoing, certain NOL carryforwards, disallowed business interest carryforwards and other tax attributes may need to be written off or have a valuation allowance maintained against them which may result in a material charge to income tax expense.

ITEM 1B. *Unresolved Staff Comments*

Not applicable.

ITEM 2. *Properties*

Information regarding our properties is included in Item 1 and in the Supplementary Information included in Item 8 of this report.

ITEM 3. *Legal Proceedings*

Litigation and Regulatory Proceedings

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 6 of the notes to our consolidated financial statements included in Item 8 of this report for information regarding our estimation and provision for potential losses related to litigation and regulatory proceedings.

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.

We and other natural gas producers have been named in various lawsuits alleging underpayment of royalties and other shares of the proceeds of production. 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 amounts owed 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 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 or other shares of the proceeds of production 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. We intend to vigorously defend these claims.

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 $36 million.

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 USACE and the Pennsylvania Department of Environmental Protection (PADEP) regarding potential violations of the permitting requirements of the federal 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.

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 are in 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. We intend to vigorously defend these claims.

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

The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17CFR 229.104) is included in Exhibit 95.1 to this Annual Report on Form 10-K.

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 NYSE under the symbol "CHK".

Shareholders

As of February 19, 2020, there were approximately 1,940 holders of record of our common stock and approximately 308,000 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, 2019:

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
				($ in millions)
October 1, 2019 through October 31, 2019	44,323	$ 1.44	—	$ —
November 1, 2019 through November 30, 2019	—	$ —	—	$ —
December 1, 2019 through December 31, 2019	—	$ —	—	$ —
Total	44,323	$ —	—	

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

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, 2019, 2018, 2017, 2016 and 2015. 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. Financial information for prior periods has been recast to reflect retrospective application of the successful efforts method of accounting. See Notes 1 and 2 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the change in accounting principle.

	Years Ended December 31,				
	2019	2018	2017	2016	2015
	($ in millions, except per share data)				
STATEMENT OF OPERATIONS DATA:					
Total revenues	$ 8,595	$ 10,030	$ 10,039	$ 8,705	$ 13,794
Net income (loss) available to common stockholders[a]	$ (416)	$ 133	$ (631)	$ (4,018)	$ (11,383)
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ (0.25)	$ 0.15	$ (0.70)	$ (5.26)	$ (17.18)
Diluted	$ (0.25)	$ 0.15	$ (0.70)	$ (5.26)	$ (17.18)
CASH DIVIDEND DECLARED PER COMMON SHARE	$ —	$ —	$ —	$ —	$ 0.0875
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 16,193	$ 12,735	$ 14,925	$ 17,048	$ 21,432
Long-term debt, net of current maturities	$ 9,073	$ 7,341	$ 9,921	$ 9,938	$ 10,311
Total equity	$ 4,401	$ 2,133	$ 1,943	$ 2,565	$ 5,256

(a) Includes $11 million, $131 million, $814 million, $563 million and $11.590 billion of impairments of oil and gas properties and other fixed assets for the years ended December 31, 2019, 2018, 2017, 2016 and 2015, respectively.

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 of this report.

Recent 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 717.4 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 achieved $250 million of cost savings in 2019 and 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;
- entered into a secured 4.5-year term loan facility for $1.5 billion to finance a tender offer for unsecured notes issued by Brazos Valley Longhorn and Brazos Valley Longhorn Finance Corp., each a wholly owned subsidiary of Chesapeake, and to fund the retirement of Brazos Valley Longhorn's secured revolving credit facility;
- exchanged new 11.5% Senior Secured Second Lien Notes due 2025 for 8.00% Senior Notes due 2027, 8.00% Senior Notes due 2026, 8.00% Senior Notes due 2025, 7.50% Senior Notes due 2026 and 7.00% Senior Notes due 2024. Also, we issued an additional $120 million of 11.5% Senior Secured Second Lien Notes due 2025 pursuant to a private offering, at 89.75% of par. These transactions resulted in the removal of approximately $900 million principal amount of debt from the company's balance sheet.
- privately negotiated exchanges of approximately $507 million principal amount of our outstanding senior notes for 235,563,519 shares of common stock and $186 million principal amount of our outstanding convertible senior notes for 73,389,094 shares of common stock, reducing annual interest payments;
- exchanged 40,000 shares of our 5.75% (Series A) Cumulative Convertible Preferred Stock for 10,367,950 shares of common stock, reducing annual preferred stock dividend payments;
- extended our debt maturity profile by privately exchanging approximately $884 million aggregate principal amount of our existing 6.625% Senior Notes due 2020, 6.875% Senior Notes due 2020, 6.125% Senior Notes due 2021 and 5.375% Senior Notes due 2021 for approximately $919 million aggregate principal amount of new 8.00% Senior Notes due 2026; and
- improved our cost structure by reducing combined production, gathering, processing and transportation and general and administrative expenses by approximately $0.79 per boe, or $290 million in 2019 compared to 2018, or 13%. The primary driver in the reduction is lower gathering, processing and transportation expenses due to certain 2018 divestitures and recently renegotiated contracts.

In 2020 and beyond, our focus remains concentrated on four long-term strategic priorities:

- reduce total leverage to achieve long-term net debt/EBITDAX of 2x;
- achieve sustained free cash flow generation;
- improve margins through financial discipline and operating efficiencies; and
- maintain industry leading environmental and safety performance.

Natural gas prices are at their lowest levels since the first half of 2016. Accordingly, a majority of our 2020 capital will be allocated to our higher margin oil assets with total expected 2020 capital expenditures being approximately 30% lower than 2019 while maintaining flat oil production. We plan to seek the lowest capital program possible to reach and sustain positive cash flow.

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 believe the prolonged lower commodity price environment has fundamentally changed the expectations of capital markets, resulting in new capital being both more difficult and more expensive to access. Currently, capital markets are no longer willing to fund organic growth. We believe our strategic priorities are consistent with these expectations as we look to continue to increase our cash flow and expand our margins by focusing on high-return drilling locations and reduced capital and operating costs using cash generated from operations and asset sales. We look to continue to reduce debt on our balance sheet with asset sales and liability management activities similar to those completed in 2019.

Change in Accounting Principle

During the first quarter of 2019, we changed our method of accounting for our oil and natural gas exploration and development activities from the full cost method to the successful efforts method of accounting. Financial information for all periods presented has been recast to reflect retrospective application of the successful efforts method of accounting. See Notes 1 and 2 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the change in accounting principle.

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, 2019, we had a cash balance of $6 million compared to $4 million as of December 31, 2018, and a net working capital deficit of $1.141 billion as of December 31, 2019, compared to a net working capital deficit of $1.289 billion as of December 31, 2018. As of December 31, 2019, our working capital deficit includes $385 million of debt due in the next 12 months. Our total principal debt as of December 31, 2019 was $8.916 billion compared to $8.168 billion as of December 31, 2018. As of December 31, 2019, we had $1.351 billion of borrowing capacity available under our revolving credit facility, with outstanding borrowings of $1.590 billion and $59 million utilized for various letters of credit. See Note 5 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.

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 our exposure to adverse market price changes, we enter 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 better predict the total revenue we expect to receive.

As of February 19, 2020, including January and February derivative contracts that have settled, approximately 70% of our 2020 forecasted oil, natural gas and NGL production revenue was hedged. We had approximately 76% downside oil price protection through swaps and collars at an average price of $59.90 per bbl. We had 39% downside gas price protection through swaps at $2.76 per mcf and 14% under put spread arrangements based on an average bought put NYMEX price of $2.05 per mcf and exposure below an average sold put NYMEX price of $1.80 per mcf.

Oil Derivatives[a]

Year	Type of Derivative Instrument	Notional Volume	Average NYMEX Price
		(mmbbls)	
2020	Swaps	30	$59.59
2020	Two-way collars	2	$65.00/$83.25
2020	Basis protection swaps	12	$2.57
2021	Calls	4	$61.58
2022	Calls	4	$61.58

Natural Gas Derivatives[a]

Year	Type of Derivative Instrument	Notional Volume	Average NYMEX Price
		(bcf)	
2020	Swaps	265	$2.76
2020	Calls	22	$12.00
2020	Basis protection swaps	53	$0.03
2020	Put spread[b]	94	$1.80/$2.05
2021	Call swaptions	15	$2.80
2021	Calls	96	$2.75
2022	Call swaption	15	$2.80

(a) Includes amounts settled in January and February 2020.

(b) *Put spread:* These instruments contain a fixed floor price (bought put) and sub floor price (sold put). If the market price exceeds the bought put strike, we receive the market price. If the market price is between the bought put and sold put strike prices, we receive the bought put price. If the market price falls below the subfloor, we receive the market price plus the difference between the sold put and bought put.

See Note 14 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 are committed to reducing total leverage to achieve long-term net debt/EBITDAX of 2x. To accomplish this goal, we intend to allocate our capital expenditures to projects we believe offer the highest return and value 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 flows from operations, but also increasing our cash flows from operations generated per barrel of oil equivalent production. We continue to seek opportunities to reduce cash costs (production, gathering, processing and transportation and general and administrative), improve our production volumes from existing wells, and achieve additional operating and capital efficiencies with a focus on growing our oil volumes.

We may continue to use a combination of cash, borrowings and issuances of our common stock or other securities and the proceeds from asset sales to retire our outstanding debt or preferred stock through privately negotiated transactions, open market repurchases, redemptions, exchanges, tender offers or otherwise, but we are under no obligation to do so.

Revolving Credit Facility

Our revolving credit facility matures in September 2023 and the current aggregate commitment of the lenders and borrowing base under the facility is $3.0 billion. The 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. Scheduled borrowing base redeterminations will continue to occur semiannually. Our next borrowing base redetermination is scheduled for the second quarter of 2020. Borrowings under the facility bear interest at a variable rate. As of December 31, 2019, we had outstanding borrowings of $1.590 billion under our revolving credit facility and had used $59 million for various letters of credit. See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the terms of our revolving credit facility. As of December 31, 2019, we were in compliance with all applicable financial covenants under the credit agreement. As of December 31, 2019, our leverage ratio was approximately 3.43 to 1, our first lien leverage ratio was approximately 1.21 to 1 and our fixed charge coverage ratio was approximately 3.64 to 1.

Term Loan

In December 2019, we entered into a secured 4.5-year term loan facility in an aggregate principal amount of $1.5 billion for net proceeds of approximately $1.455 billion. Our obligations under the new facility are unconditionally guaranteed on a joint and several basis by the same subsidiaries that guarantee our revolving credit facility and second lien notes (including BVL and its subsidiaries) and are secured by first-priority liens on the same collateral securing our revolving credit facility (with a position in the collateral proceeds waterfall junior to the revolving credit facility). The term loan bears interest at a rate of London Interbank Offered Rate (LIBOR) plus 8.00% per annum, subject to a 1.00% LIBOR floor, or the Alternative Base Rate (ABR) plus 7.00% per annum, subject to a 2.00% ABR floor, at our option. The loan was made at 98% of par. We used the net proceeds to finance tender offers for our unsecured BVL senior notes and to fund the retirement of BVL's secured revolving credit facility. The term loan matures in June 2024 and voluntary prepayments are subject to a make-whole premium prior to the 18-month anniversary of the closing of the term loan, a premium to par of 5.00% from the 18-month anniversary until but excluding the 30-month anniversary, a premium to par of 2.5% from the 30-month anniversary until but excluding the 42-month anniversary and at par beginning on the 42-month anniversary. The term loan may be subject to mandatory prepayments and offers to prepay with net cash proceeds of certain issuances of debt, certain asset sales and other dispositions of collateral and upon a change of control. See Note 5 of the notes to our consolidated financial statements included in Item 8 for further discussion of the term loan facility.

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, 2019:

	Payments Due By Period				
	Total	**2020**	**2021-2022**	**2023-2024**	**2025 and Beyond**
	($ in millions)				
Long-term debt:					
Principal[a]	$ 8,916	$ 385	$ 583	$ 3,888	$ 4,060
Interest	3,314	705	1,338	1,101	170
Finance lease obligation[b]	20	10	10	—	—
Operating lease obligations[c]	28	10	9	4	5
Operating commitments[d]	8,056	1,143	1,955	1,479	3,479
Standby letters of credit	59	59	—	—	—
VPP obligation[e]	64	55	9	—	—
Other	13	3	8	2	—
Total contractual cash obligations[f]	$ 20,470	$ 2,370	$ 3,912	$ 6,474	$ 7,714

(a) See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our long-term debt.

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

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

(d) See Note 6 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.

(e) See Note 7 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our VPP obligation.

(f) 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 14 and 22, 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.

Capital Expenditures

Our 2020 capital expenditures program is expected to generate greater capital efficiency than the 2019 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 2020 capital expenditures are $1.3 – $1.6 billion compared to our 2019 capital spending level of $2.2 billion. We reduced the midpoint of our 2020 range by approximately 30% from 2019 spending to improve our cash flow profile. Management continues to review operational plans for 2020 and beyond, which could result in changes to projected capital expenditures and projected revenues from sales of oil, natural gas and NGL.

Credit Risk

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 24, 2020, we have posted approximately $60 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 $220 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, 2019, 2018 and 2017. See Note 3 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,		
	2019	**2018**	**2017**
		($ in millions)	
Cash provided by operating activities	$ 1,623	$ 1,730	$ 475
Proceeds from issuances of debt, net	1,563	1,236	1,585
Proceeds from revolving credit facility borrowings, net	496	—	781
Proceeds from divestitures of proved and unproved properties, net	130	2,231	1,249
Proceeds from sales of other property and equipment, net	6	147	55
Proceeds from sales of investments	—	74	—
Total sources of cash and cash equivalents	$ 3,818	$ 5,418	$ 4,145

Cash Flow from Operating Activities

Cash provided by operating activities was $1.623 billion, $1.730 billion and $475 million in 2019, 2018 and 2017, respectively. The decrease in 2019 is primarily the result of lower prices for the oil, natural gas and NGL we sold as well as certain cash expenditures related to our WildHorse acquisition. The increase in 2018 is primarily the result of higher prices for the oil, natural gas and NGL we sold. 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 2019, 2018 and 2017. See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

	Years Ended December 31,					
	2019		2018		2017	
	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds
	($ in millions)					
Term loan	$ 1,500	$ 1,455	$ —	$ —	$ —	$ —
Senior secured second lien notes	120	108	—	—	—	—
Senior notes	—	—	1,250	1,236	1,600	1,585
Total	$ 1,620	$ 1,563	$ 1,250	$ 1,236	$ 1,600	$ 1,585

Divestitures of Proved and Unproved Properties

During 2019, we divested certain non-core assets for approximately $130 million. 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, we divested certain non-core assets for approximately $1.249 billion. Proceeds from these transactions were used to repay debt and fund our development program. See Note 3 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, 2019, 2018 and 2017:

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
Oil and Natural Gas Expenditures:			
Drilling and completion costs	$ 2,180	$ 1,848	$ 2,113
Acquisitions of proved and unproved properties	35	128	88
Total oil and natural gas expenditures	2,215	1,976	2,201
Other Uses of Cash and Cash Equivalents:			
Cash paid to purchase debt	1,073	2,813	2,592
Business combination, net	353	—	—
Payments on revolving credit facility borrowings, net	—	362	—
Extinguishment of other financing	—	122	—
Additions to other property and equipment	48	21	21
Cash paid for preferred stock dividends	91	92	183
Distributions to noncontrolling interest owners	4	6	8
Other	32	27	17
Total other uses of cash and cash equivalents	1,601	3,443	2,821
Total uses of cash and cash equivalents	$ 3,816	$ 5,419	$ 5,022

Drilling and Completion Costs

Our drilling and completion costs increased in 2019 compared to 2018 primarily as a result of increased completion activity in our oil plays. We spud, completed, and connected wells at a higher average working interest in 2019 compared to 2018 due to the divestiture of the Utica asset and the acquisition of the Brazos Valley asset. Our average operated rig count was 18 rigs and spud wells were 333 in 2019 compared to an average operated rig count of 17 rigs and 322 spud wells in 2018 and 17 rigs and 341 spud wells in 2017. We completed 370 operated wells in 2019 compared to 351 in 2018 and 401 in 2017.

Business Combination - Acquisition of WildHorse

In 2019, we acquired WildHorse for approximately 717.4 million shares of our common stock and $381 million less $28 million of cash held by WildHorse as of the acquisition date. See Note 3 of the notes to our consolidated financial statements included in Item 1 of Part I of this report for further discussion of the acquisition.

Cash Paid to Purchase Debt

In 2019, we repurchased $698 million principal amount of our BVL Senior Notes for $693 million and retired our BVL revolving credit facility for $1.028 billion. We also repaid upon maturity $380 million principal amount of our Floating Rate Senior Notes due April 2019. 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.

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.

Dividends

We paid dividends of $91 million and $92 million on our preferred stock during 2019 and 2018, respectively, and we paid dividends of $183 million on our preferred stock during 2017, including $92 million of dividends in arrears that had been suspended throughout 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

2019	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	946	2.48	—	—	158	33	14.88
Haynesville	—	—	702	2.42	—	—	117	24	14.50
Eagle Ford	58	61.22	153	2.73	19	17.04	102	21	41.72
Brazos Valley	33	59.29	49	1.79	5	8.04	47	10	44.96
Powder River Basin	19	54.28	86	2.47	5	16.63	38	8	34.31
Mid-Continent	8	55.69	57	2.13	4	18.02	21	4	29.91
Retained assets[a]	118	59.16	1,993	2.45	33	15.62	483	100	25.57
Divested assets[b]	—	—	2	0.40	—	—	1	—	17.55
Total	118	59.16	1,995	2.45	33	15.62	484	100%	25.57

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	—	—	788	2.90	—	—	131	25	17.42
Eagle Ford	60	69.02	136	3.46	20	25.59	102	20	50.01
Powder River Basin	11	63.36	64	2.90	4	26.83	25	5	38.12
Mid-Continent	9	64.17	60	2.77	4	26.50	24	5	36.61
Retained assets[a]	80	67.72	1,876	3.01	28	25.90	420	81	27.97
Divested assets[b]	10	63.54	402	2.90	24	27.21	101	19	24.37
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	25	14.67
Haynesville	—	—	784	2.85	—	—	131	24	17.10
Eagle Ford	58	52.37	141	3.31	18	22.98	100	18	39.33
Powder River Basin	6	50.06	37	3.01	3	27.37	15	3	32.52
Mid-Continent	8	49.26	66	2.79	5	23.10	23	4	28.92
Retained assets[a]	72	51.82	1,832	2.71	26	23.42	403	74	23.05
Divested assets[b]	18	47.83	574	2.92	31	22.98	145	26	22.41
Total	90	51.03	2,406	2.76	57	23.18	548	100%	22.88

(a) Includes assets retained as of December 31, 2019.

(b) Divested assets include certain Utica assets in Ohio in 2018 and Haynesville assets in 2017 as well as certain Mid-Continent assets in both 2018 and 2017.

Oil, Natural Gas and NGL Sales

	Years Ended December 31,				
	2019	change	2018	change	2017
	($ in millions)				
Oil	$ 2,543	16 %	$ 2,201	32%	$ 1,668
Natural gas	1,782	(28)%	2,486	3%	2,422
NGL	192	(62)%	502	4%	484
Oil, natural gas and NGL sales	$ 4,517	(13)%	$ 5,189	13%	$ 4,574

2019 vs. 2018. Oil revenues increase of $342 million is primarily attributable to increased production volumes through the acquisition of WildHorse offset by a decrease in prices. Increased oil volumes resulted in a $605 million increase offset by a decrease in prices resulting in a $263 million decrease in revenues. Natural gas and NGL revenues decrease of $1.014 billion is primarily attributable to a decrease in natural gas and NGL prices and a decrease in production volumes primarily due to divestiture activity. Decreased natural gas and NGL prices and production volumes resulted in a $650 million and $364 million decrease to revenues, respectively.

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.

See Note 9 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,		
	2019	2018	2017
	($ in millions)		
Oil derivatives – realized gains (losses)	$ 36	$ (321)	$ 70
Oil derivatives – unrealized gains (losses)	(248)	445	(134)
Total gains (losses) on oil derivatives	(212)	124	(64)
Natural gas derivatives – realized gains (losses)	114	7	(9)
Natural gas derivatives – unrealized gains (losses)	103	(154)	489
Total gains (losses) on natural gas derivatives	217	(147)	480
NGL derivatives – realized gains (losses)	—	(13)	(4)
NGL derivatives – unrealized gains (losses)	—	2	(1)
Total gains (losses) on NGL derivatives	—	(11)	(5)
Total gains (losses) on oil, natural gas and NGL derivatives	$ 5	$ (34)	$ 411

See Note 14 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,				
	2019	change	2018	change	2017
	($ in millions)				
Marketing revenues	$ 3,967	(22)%	$ 5,076	13%	$ 4,511
Marketing expenses	4,003	(22)%	5,158	12%	4,598
Marketing margin	$ (36)	56 %	$ (82)	6%	$ (87)

2019 vs. 2018. Marketing revenues and expenses decreased in 2019 primarily as a result of decreased oil, natural gas and NGL prices received in our marketing operations. Marketing margin improved as a result of improved pricing on oil inventory and better margins on non-equity gas and oil transactions offset by an increase in pipeline deficiency fees.

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. Marketing margin was negatively impacted by downstream pipeline delivery commitments.

Other Revenue

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
Other revenue	$ 63	$ 63	$ 67

Other revenue primarily relates to the amortization of deferred VPP revenue. Our remaining deferred revenue balance of $64 million will be amortized on a straight-line basis through February 2021. See Note 7 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our VPPs.

Gains (Losses) on Sales of Assets

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
Gains (losses) on sales of assets	$ 43	$ (264)	$ 476

In 2019, we received proceeds of approximately $136 million, net of post-closing adjustments, and recognized a net gain of approximately $43 million, primarily for the sale of non-core 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 for net proceeds of $1.868 billion to Encino and recognized a loss of $273 million associated with the transaction. Also 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, and we recognized a gain of approximately $12 million associated with the transactions.

In 2017, 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, and recognized a gain of approximately $326 million.

See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of these transactions.

Oil, Natural Gas and NGL Production Expenses

	Years Ended December 31,				
	2019	change	2018	change	2017
	($ in millions)				
Oil, natural gas and NGL production expenses					
Marcellus	$ 32	(6)%	$ 34	21 %	$ 28
Haynesville	47	(18)%	57	8 %	53
Eagle Ford	180	(1)%	181	(3)%	187
Brazos Valley	96	n/a	—	n/a	—
Powder River Basin	71	45 %	49	69 %	29
Mid-Continent	94	(4)%	98	(8)%	107
Retained Assets[(a)]	520	24 %	419	4 %	404
Divested Assets[(b)]	—	(100)%	55	(51)%	113
Total oil, natural gas and NGL production expenses	$ 520	10 %	$ 474	(8)%	$ 517
	($ per boe)				
Oil, natural gas and NGL production expenses					
Marcellus	$ 0.56	(16)%	$ 0.67	16 %	$ 0.58
Haynesville	$ 1.10	(8)%	$ 1.20	9 %	$ 1.10
Eagle Ford	$ 4.79	(2)%	$ 4.87	(5)%	$ 5.13
Brazos Valley	$ 5.62	n/a	$ —	n/a	$ —
Powder River Basin	$ 5.13	(4)%	$ 5.34	(3)%	$ 5.51
Mid-Continent	$ 12.22	8 %	$ 11.31	(8)%	$ 12.31
Retained Assets[(a)]	$ 2.94	8 %	$ 2.73	(1)%	$ 2.75
Divested Assets[(b)]	$ —	(100)%	$ 1.49	(30)%	$ 2.14
Total oil, natural gas and NGL production expenses per boe	$ 2.94	18 %	$ 2.50	(3)%	$ 2.59

(a) Includes assets retained as of December 31, 2019.

(b) Divested assets include certain Utica assets in Ohio in 2018 and Haynesville assets in 2017 as well as certain Mid-Continent assets in both 2018 and 2017.

2019 vs. 2018. The absolute and per unit increase was the result of the acquisition of WildHorse in 2019 and increased production volumes in the Powder River Basin, partially offset by the sale of certain oil and natural gas properties in 2018 and 2019. Production expenses in 2019 included approximately $11 million associated with VPP production volumes.

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. Production expenses in 2018 included approximately $15 million 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,		
	2019	2018	2017
	($ in millions, except per unit)		
Oil, natural gas and NGL gathering, processing and transportation expenses	$ 1,082	$ 1,398	$ 1,471
Oil ($ per bbl)	$ 3.20	$ 4.30	$ 3.94
Natural gas ($ per mcf)	$ 1.21	$ 1.32	$ 1.34
NGL ($ per bbl)	$ 5.32	$ 8.37	$ 7.88
Total ($ per boe)	$ 6.13	$ 7.35	$ 7.36

2019 vs. 2018. The absolute and per unit decrease for oil and natural gas gathering, processing and transportation expenses was primarily due to the divestiture of our Utica Shale properties in 2018.

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.

Severance and Ad Valorem Taxes

	Years Ended December 31,				
	2019	change	2018	change	2017
	($ in millions, except per unit)				
Severance taxes	$ 144	16%	$ 124	39%	$ 89
Ad valorem taxes	80	23%	65	44%	45
Severance and ad valorem taxes	$ 224	19%	$ 189	41%	$ 134
Severance taxes per boe	$ 0.81	25%	$ 0.65	48%	$ 0.44
Ad valorem taxes per boe	0.46	35%	0.34	55%	0.22
Severance and ad valorem taxes per boe	$ 1.27	28%	$ 0.99	50%	$ 0.66

2019 vs. 2018. The absolute and per unit increase in severance taxes was primarily due to the addition of Texas assets through our acquisition of WildHorse, expiring tax exemptions in Haynesville and the divestiture of Ohio assets that were taxed at a lower rate. The absolute and per unit increase in ad valorem taxes was primarily due to a change in the mix of taxable oil and natural gas reserves by state. The addition of Texas assets through our acquisition of WildHorse increased the amount of oil and natural gas reserves subject to ad valorem tax whereas the divestiture of Ohio assets decreased the amount of oil and gas reserves not subject to ad valorem tax.

2018 vs. 2017. The absolute and per unit increase in severance taxes was primarily due to higher prices received for our oil, natural gas and NGL production, offset by lower production volumes. The total per unit increase in ad valorem taxes was the result of increased ad valorem tax primarily due to higher prices received for our oil, natural gas and NGL production.

Exploration Expenses

	Years Ended December 31,				
	2019	change	2018	change	2017
	($ in millions, except per unit)				
Impairments of unproved properties	$ 32	(46)%	$ 59	(72)%	$ 214
Dry hole expense	25	(32)%	37	n/a	—
Geological and geophysical expense and other	27	(59)%	66	214 %	21
Exploration expense	$ 84	(48)%	$ 162	(31)%	$ 235

2019 vs. 2018. The decrease in exploration expense was primarily due to fewer impairments of unproved properties and fewer exploratory geological and geophysical projects. In addition, we recognized a reduction in delay rental expense primarily due to the divested Utica operating area in 2018.

2018 vs. 2017. The decrease in exploration expense was primarily due to fewer impairments of unproved properties, partially offset by an increase in dry hole expense and exploratory geological and geophysical projects.

General and Administrative Expenses

	Years Ended December 31,				
	2019	**change**	**2018**	**change**	**2017**
	($ in millions, except per unit)				
Gross overhead	$ 682	(4)%	$ 714	(10)%	$ 791
Allocated to production expenses	(132)	(6)%	(141)	(20)%	(177)
Allocated to marketing expenses	(14)	(30)%	(20)	(31)%	(29)
Allocated to exploration expenses	(11)	10 %	(10)	67 %	(6)
Allocated to sand mine expense	(7)	— %	—	— %	—
Capitalized general and administrative expenses	(56)	4 %	(54)	(10)%	(60)
Reimbursed from third parties	(147)	(5)%	(154)	(17)%	(186)
General and administrative expenses, net	$ 315	(6)%	$ 335	1 %	$ 333
General and administrative expenses, net per boe	$ 1.78	1 %	$ 1.76	5 %	$ 1.67

2019 vs. 2018. The decrease in gross overhead expense is primarily due to compensation reductions in our long-term incentives that are tied to the Company's equity performance.

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.

Restructuring and Other Termination Costs. In 2019, we incurred a charge of $12 million related to one-time termination benefits for certain employees. In January 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. See Note 21 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,		
	2019	**2018**	**2017**
	($ in millions)		
Provision for legal contingencies, net	$ 19	$ 26	$ (38)

The 2019 and the 2018 amounts consist of accruals for loss contingencies 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 6 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of royalty claims.

Depreciation, Depletion and Amortization

	Years Ended December 31,				
	2019	change	2018	change	2017
	($ in millions, except per unit)				
Depreciation, depletion and amortization	$ 2,264	30%	$ 1,737	2%	$ 1,697
Depreciation, depletion and amortization per boe	$ 12.82	40%	$ 9.13	8%	$ 8.49

The absolute and per unit increases in 2018 and 2019 are primarily the result of a higher depletion rate. The depletion rate increases are driven by a higher concentration of our production mix and capital deployment in liquids-rich operating areas, which generally involve higher finding costs per boe relative to gas-rich operating areas. The depletion rate in 2019 also reflects our acquisition of WildHorse assets, located in a liquids-rich operating area.

Impairments

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
Impairments due to lower forecasted commodity prices	$ 8	$ 23	$ 27
Impairments due to reduction in future development[(a)]	—	—	560
Impairments due to anticipated sale	—	55	222
Total impairments of oil and natural gas properties	8	78	809
Impairments of other fixed assets	3	53	5
Total impairments	$ 11	$ 131	$ 814

(a) The impairment was the result of an updated development plan in 2017, which included a removal of PUDs from properties in the process of being divested in the Mid-Continent operating area.

Other fixed assets. 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. See Note 19 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,				
	2019	change	2018	change	2017
	($ in millions)				
Other operating expense	$ 92	n/a	$ —	(100)%	$ 416

In 2019, we recorded approximately $37 million of costs related to our acquisition of WildHorse which consisted of consulting fees, financial advisory fees, legal fees and travel and lodging expenses. In addition, we recorded approximately $38 million of severance expense as a result of the acquisition of WildHorse. A majority of the WildHorse executives and employees were terminated at the time of acquisition. These executives and employees were entitled to severance benefits in accordance with existing employment agreements.

The 2017 amount consists of discrete costs incurred to terminate various gathering and transportation agreements, including those associated with oil and natural gas asset divestitures. See Note 20 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,		
	2019	2018	2017
	($ in millions)		
Interest expense on senior notes	$ 578	$ 591	$ 551
Interest expense on term loan	4	86	127
Amortization of loan discount, issuance costs and other	3	24	40
Amortization of premium	(5)	(88)	(138)
Interest expense on revolving credit facility	96	37	39
Realized gains on interest rate derivatives	(5)	(3)	(3)
Unrealized losses on interest rate derivatives	4	2	4
Capitalized interest	(24)	(16)	(19)
Total interest expense	$ 651	$ 633	$ 601
Interest expense per boe	$ 3.68	$ 3.33	$ 2.99
Average senior notes borrowings	$ 7,857	$ 8,160	$ 7,714
Average credit facility borrowings	$ 1,934	$ 505	$ 443
Average term loan borrowings	$ 37	$ 911	$ 1,446

See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our debt instruments.

Gains (Losses) on Investments.

FTS International Inc. (NYSE: FTSI). In 2018, FTS International, Inc. 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 2019, the hydraulic fracturing industry experienced challenging operating conditions resulting in the current fair value of our investment in FTSI falling below book value of $65 million and remaining below that value as of the end of the year. Based on FTSI's 2019 operating results and FTSI's share price of $1.04 per share as of December 31, 2019, we determined that the reduction in fair value is other-than-temporary, and recognized an impairment of our investment in FTSI of approximately $43 million. We will continue to monitor the hydraulic fracturing industry, FTSI operating results and FTSI share price for indicators that the reduction in fair value is other-than-temporary, which could result in an additional impairment of our investment in FTSI. See Note 18 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our investments.

JWH Midstream LLC (JWH). In 2019, in connection with the acquisition of WildHorse, we obtained a 50% membership interest in JWH Midstream LLC (JWH). The carrying value of our investment in JWH, which was being accounted for as an equity method investment, was approximately $17 million. In 2019, we paid approximately $7 million to terminate our involvement in the partnership. This removed us from any future obligations related to this joint venture and, therefore, we impaired the full value of the investment and recognized approximately $24 million of impairment expense in 2019.

Gains (Losses) on Purchases or Exchanges of Debt. In 2019, we privately negotiated exchanges of approximately $507 million principal amount of our outstanding senior notes for 235,563,519 shares of common stock and $186 million principal amount of our outstanding convertible senior notes for 73,389,094 shares of common stock. We recorded an aggregate net gain of approximately $64 million associated with the exchanges. Additionally, in various transactions throughout 2019, we repurchased approximately $698 million principal amount of the BVL Senior Notes, recognizing a net $10 million gain on the transactions.

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.

Other Income. In 2019, we recognized $9 million of other income from the sale of seismic data licenses to third parties. The remaining amount in 2019 was from other non-operating miscellaneous 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.

Income Tax Expense (Benefit). We recorded an income tax benefit of $331 million in 2019, an income tax benefit of $10 million in 2018 and income tax expense of $2 million in 2017. The income tax benefit for 2019 consists mainly of a partial release of the valuation allowance maintained against our net deferred tax asset position. The partial release was a consequence of recording a net deferred tax liability of $314 million resulting from the business combination accounting for WildHorse. Other material items included in the 2019 income tax benefit include a benefit for the reversal of a liability for unrecognized tax benefits of $32 million partially offset by an expense of $10 million associated with Texas no longer being in a net deferred tax asset position, and a current state income tax expense of $6 million. See Note 10 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 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.

Impairments. Long-lived assets used in operations, including proved oil and gas properties, are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. If there is an indication the carrying amount of an asset may not be recovered, the asset is assessed by management through an established process in which changes to significant assumptions such as prices, volumes, and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value by discounting using a weighted average cost of capital. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is assessed by management using the income approach. Level 3 inputs associated with the calculation of discounted cash flows used in the impairment analysis include our estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves and other relevant data. Additionally, we utilize a combination of NYMEX strip pricing and consensus pricing, adjusted for differentials, to value the reserves.

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 carryforwards and disallowed business interest 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 any loss that creates a 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, 2019, and 2018, we had deferred tax assets totaling $2.449 billion and $3.231 billion upon which we had a valuation allowance of $1.805 billion and $2.011 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 10 of the notes to our consolidated financial statements included in Item 8 of this report.

Contingencies. We are subject to various legal proceedings, claims, and liabilities that arise in the ordinary course of business. Except for contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, we accrue losses 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, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. Our in-house legal personnel regularly assess contingent liabilities and, in certain circumstances, consult with third-party legal counsel or consultants to assist in the evaluation of our liability for these contingencies.

We make judgments and estimates when we establish liabilities for litigation and other contingent matters. Estimates of litigation-related liabilities are based on the facts and circumstances of the individual case and on information currently available to us. The extent of information available varies based on the status of the litigation and our evaluation of the claim and legal arguments. In future periods, a number of factors could significantly change our estimate of litigation-related liabilities, including discovery activities; briefings filed with the relevant court; rulings from the court made pre-trial, during trial, or at the conclusion of any trial; and similar cases involving other plaintiffs and defendants that may set or change legal precedent. As events unfold throughout the litigation process, we evaluate the available information and may consult with third-party legal counsel to determine whether liability accruals should be established or adjusted.

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, 2019, and 2018, the fair values of our derivatives were net assets of $130 million and $282 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.

Disclosures About Effects of Transactions with Related Parties

Our equity method investees are considered related parties. See Note 24 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*

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our exposure to market risk. The term market risk relates to our risk of loss arising from adverse changes in oil, natural gas, and NGL prices and interest rates. These disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Price Risk

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL, which have historically been volatile. To mitigate a portion of our exposure to adverse price changes, we enter 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.

We determine 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 14 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.

For the year ended December 31, 2019, oil, natural gas, and NGL revenue, excluding any effect of our derivative instruments, were $2.543 billion, $1.782 billion, and $192 million, respectively. Based on 2019 production, oil, natural gas, and NGL revenue for the year ended December 31, 2019 would have increased or decreased by approximately $254 million, $178 million, and $19 million, respectively, for each 10% increase or decrease in prices. As of December 31, 2019, the fair values of our oil and gas derivatives were net assets of $5 million and $125 million, respectively. A 10% increase in forward oil prices would decrease the valuation of oil derivatives by $147 million while a 10% decrease would increase the valuation by $150 million. A 10% increase in forward gas prices would decrease the valuation of gas derivatives by approximately $58 million while a 10% decrease would increase the valuation by $57 million. This fair value change assumes volatility based on prevailing market parameters at December 31, 2019. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for further information on our open derivative positions.

Beginning with this report, we have revised our commodity price risk disclosure alternative from the tabular format to a sensitivity analysis, which we believe is a more commonly used and easily understood disclosure alternative. We have presented below the tabular analysis as of December 31, 2019 and 2018 for comparative purposes.

Oil, Natural Gas and NGL Derivatives

As of December 31, 2019, and 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. Swaptions allow the counterparty, on a specific date, to extend an existing fixed-price swap for a certain period of time or to increase the notional volumes of an existing fixed-price swap.
- *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, 2019, 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	24	$ 58.54	$ —	$ —	$ —	$ (7)
Collars:						
Short-term	2	$ —	$ 83.25	$ 65.00	$ —	14
Basis Protection Swaps:						
Short-term	8	$ —	$ —	$ —	$ 2.49	(2)
Total Oil						5
	(bcf)	**($ per mcf)**				
Natural Gas:						
Swaps:						
Short-term	265	$ 2.76	$ —	$ —	$ —	125
Call Options (sold):						
Short-term	22	$ —	$ 12.00	$ —	$ —	—
Call Swaptions:						
Long-term	29	$ 2.80	$ —	$ —	$ —	(2)
Basis Protection Swaps:						
Short-term	30	$ —	$ —	$ —	$ 0.08	2
Total Natural Gas						125
				Total Commodities		$ 130

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

	Volume	Weighted Average Price: Fixed	Call	Put	Differential	Fair Value 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

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						
	2020	2021	2022	2023	2024	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate	$ 385	$ 294	$ 289	$ 174	$ 624	$ 4,060	$ 5,826
Average interest rate	6.38%	5.80%	4.88%	5.75%	7.00%	9.34%	8.39%
Debt – variable rate	$ —	$ —	$ —	$ 1,590	$ 1,500	$ —	$ 3,090
Average interest rate	—%	—%	—%	4.78%	9.93%	—%	7.28%

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 facility and our term loan facility. 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.

During the year ended December 31, 2019, $5 million of net gains related to settled interest rate derivative contracts were transferred from our senior note liability or unrealized gains or losses and recorded within interest expense as realized gains or losses. As of December 31, 2019, there were no remaining open or settled interest rate derivative contracts.

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, 2019.

The effectiveness of the Company's internal control over financial reporting, as of December 31, 2019, 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, 2020

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, 2019 and 2018, and the related consolidated statements of operations, of comprehensive income (loss), of stockholders’ equity and of cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 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, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which it accounts for oil and natural gas exploration and development activities from the full cost method to the successful efforts method in 2019. This matter is also discussed below as a critical audit matter.

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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Acquisition of Proved Oil and Natural Gas Properties and Related Fair Value Estimate

As described in Note 3 to the consolidated financial statements, $3.3 billion of the purchase price from the February 2019 business combination of Wildhorse Resource Development Corporation was allocated to proved oil and natural gas properties. Management applied the applicable accounting guidance, under which an acquirer should recognize the identifiable assets acquired and the liabilities assumed on the acquisition date at fair value. The fair value estimate of proved oil and natural gas properties as of the acquisition date was based on estimated proved oil and natural gas reserves and related future net cash flows discounted using a weighted average cost of capital, including estimates of future production rates and future development costs. As disclosed by management, the accuracy of the reserve estimates 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. The estimates of oil and natural gas reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the acquisition of proved oil and natural gas properties and related fair value estimate is a critical audit matter are there was significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating the significant assumptions used in developing the estimates, including future production rates, future development costs, and the weighted average cost of capital. In addition, the audit effort involved the use of professionals with specialized skill and knowledge in evaluating the audit evidence obtained from these procedures.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the acquisition accounting, including the purchase price allocation based upon estimates of fair value, management's estimates of proved oil and natural gas reserves in determining the fair value of acquired proved oil and natural gas properties, and the calculation of the weighted average cost of capital. These procedures also included, among others, evaluating the significant assumptions used by management in developing these estimates, including future production rates, future development costs, and the weighted average cost of capital. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved oil and natural gas reserves. As a basis for this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of the data used by the specialists and an evaluation of the specialists' findings. Evaluating the significant assumptions relating to the estimates of proved oil and gas reserves also involved obtaining evidence to support the reasonableness of the assumptions, including whether the assumptions used were reasonable considering the past performance of the acquired entity, and whether they were consistent with evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of management's model and evaluating the reasonableness of the assumptions used in the model.

The Impact of Proved Oil and Natural Gas Reserves on Proved Oil and Natural Gas Properties, Net

The Company's property and equipment, net balance was $14.8 billion as of December 31, 2019, and depreciation, depletion and amortization (DD&A) expense for the year ended December 31, 2019 was $2.3 billion, both of which substantially relate to proved oil and natural gas properties. As described in Note 1 to the consolidated financial statements, the Company follows the successful efforts method of accounting for its oil and natural gas properties. Costs of drilling and equipping successful wells, costs to construct or acquire facilities, and associated asset retirement costs are depreciated using the unit-of-production (UOP) method based on total estimated proved developed oil and natural gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves. When circumstances indicate that the carrying value of proved oil and gas properties may not be recoverable, management compares unamortized capitalized costs to the expected undiscounted pre-tax future cash flows for the associated assets grouped at the lowest level for which identifiable cash flows are independent of cash flows of other assets. If the expected undiscounted pre-tax future cash flows, based on management's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized costs, the capitalized costs are reduced to fair value. Fair value is generally estimated using the income approach. The expected future cash flows used for impairment reviews and related fair value measurements are typically based on judgmental assessments of future production volumes, commodity prices, operating costs, and capital investment plans, considering all available information at the date of review. The estimates of oil and natural gas reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on proved oil and natural gas properties, net is a critical audit matter are there was significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating the significant assumptions used in developing those estimates, including future production, future pricing differentials, and future development costs.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and natural gas reserves, the calculation of DD&A expense, and the impairment assessment of proved oil and natural gas properties. These procedures also included, among others, evaluating the significant assumptions used by management in developing these estimates, including future production, future pricing differentials, and future development costs. Procedures were also performed to test the unit-of-production rate used to calculate DD&A expense. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved oil and natural gas reserves. As a basis for this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of the data used by the specialists and an evaluation of the specialists' findings. Evaluating the significant assumptions relating to the estimates of proved oil and natural gas reserves also involved obtaining evidence to support the reasonableness of the assumptions, including whether the assumptions used were reasonable considering the past performance of the Company, and whether they were consistent with evidence obtained in other areas of the audit.

C*hange in Accounting from the Full Cost Method to the Successful Efforts Method*

As described above and in Note 2, during the first quarter of 2019, the Company voluntarily changed its method of accounting for oil and natural gas exploration and development activities from the full cost method to the successful efforts method. Accordingly, financial information for prior periods has been recast to reflect retrospective application of the successful efforts method. As a result of its change in accounting principle from the full cost method to the successful efforts method, management recorded significant impairments of its proved oil and natural gas properties for historical periods to arrive at the recast financial information. As described in Note 1, under the successful efforts method of accounting, costs of drilling and equipping successful wells, costs to construct or acquire facilities, and associated asset retirement costs are depreciated using the unit-of-production (UOP) method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves. As disclosed by management, estimates of oil and natural gas reserves and their values, future production rates, future development costs and commodity pricing differentials, and the weighted average cost of capital are the most significant of these estimates. The accuracy of the reserve estimates 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. The estimates of oil and natural gas reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the change in accounting from the full cost method to the successful efforts method is a critical audit matter are there was significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves for purposes of reflecting the retrospective application of the successful efforts method, including the calculation of DD&A expense, the impairment assessments performed, and the calculation of impairment charges recorded in prior periods. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating the significant assumptions used in developing those estimates, including the weighted average cost of capital. In addition, the audit effort involved the use of professionals with specialized skill and knowledge in evaluating the audit evidence obtained from these procedures.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the change in accounting from the full cost method to the successful efforts method, management's retrospective application of the successful efforts method, including estimates of proved oil and natural gas reserves, the calculation of DD&A expense, the impairment assessments of proved oil and natural gas reserves, and the calculation of impairment charges recorded for the historical recast periods. These procedures also included, among others, evaluating the significant assumptions used by management in developing these estimates, including the weighted average cost of capital. Procedures were also performed to test the unit-of-production rate used to calculate DD&A expense, the impairment assessments, and the calculation of the impairment charges recorded. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved oil and natural gas reserves. As a basis for this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of the data used by the specialists and an evaluation of the specialists' findings. Evaluating the significant assumptions relating to the estimates of proved oil and natural gas reserves for the historical recast periods also involved obtaining evidence to support the reasonableness of the assumptions, including whether the assumptions were reasonable considering the past performance of the Company, and whether they were consistent with evidence in other areas of the audit for the historical recast periods. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of management's model and evaluating the reasonableness of the assumptions used in the model.

/s/ PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
February 27, 2020

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($2 and $1 attributable to our VIE)	$ 6	$ 4
Accounts receivable, net	990	1,247
Short-term derivative assets	134	209
Other current assets	121	138
Total Current Assets	1,251	1,598
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on successful efforts accounting:		
Proved oil and natural gas properties ($755 and $755 attributable to our VIE)	30,765	25,407
Unproved properties	2,173	1,561
Other property and equipment	1,810	1,721
Total Property and Equipment, at Cost	34,748	28,689
Less: accumulated depreciation, depletion and amortization (($713) and ($707) attributable to our VIE)	(20,002)	(17,886)
Property and equipment held for sale, net	10	15
Total Property and Equipment, Net	14,756	10,818
LONG-TERM ASSETS:		
Long-term derivative assets	—	76
Other long-term assets	186	243
TOTAL ASSETS	$ 16,193	$ 12,735

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

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

	December 31,	
	2019	2018
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 498	$ 763
Current maturities of long-term debt, net	385	381
Accrued interest	75	141
Short-term derivative liabilities	2	3
Other current liabilities ($1 and $2 attributable to our VIE)	1,432	1,599
Total Current Liabilities	2,392	2,887
LONG-TERM LIABILITIES:		
Long-term debt, net	9,073	7,341
Long-term derivative liabilities	2	—
Asset retirement obligations, net of current portion	200	155
Other long-term liabilities	125	219
Total Long-Term Liabilities	9,400	7,715
CONTINGENCIES AND COMMITMENTS (Note 6)		
EQUITY:		
Chesapeake Stockholders’ Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 5,563,458 and 5,603,458 shares outstanding	1,631	1,671
Common stock, $0.01 par value, 3,000,000,000 and 2,000,000,000 shares authorized: 1,954,558,617 and 913,715,512 shares issued	19	9
Additional paid-in capital	16,954	14,378
Accumulated deficit	(14,220)	(13,912)
Accumulated other comprehensive income (loss)	12	(23)
Less: treasury stock, at cost; 5,244,992 and 3,246,553 common shares	(32)	(31)
Total Chesapeake Stockholders’ Equity	4,364	2,092
Noncontrolling interests	37	41
Total Equity	4,401	2,133
TOTAL LIABILITIES AND EQUITY	$ 16,193	$ 12,735

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,		
	2019	2018	2017
	($ in millions except per share data)		
REVENUES AND OTHER:			
Oil, natural gas and NGL	$ 4,522	$ 5,155	$ 4,985
Marketing	3,967	5,076	4,511
Total Revenues	8,489	10,231	9,496
Other	63	63	67
Gains (losses) on sales of assets	43	(264)	476
Total Revenues and Other	8,595	10,030	10,039
OPERATING EXPENSES:			
Oil, natural gas and NGL production	520	474	517
Oil, natural gas and NGL gathering, processing and transportation	1,082	1,398	1,471
Severance and ad valorem taxes	224	189	134
Exploration	84	162	235
Marketing	4,003	5,158	4,598
General and administrative	315	335	333
Restructuring and other termination costs	12	38	—
Provision for legal contingencies, net	19	26	(38)
Depreciation, depletion and amortization	2,264	1,737	1,697
Impairments	11	131	814
Other operating expense	92	—	416
Total Operating Expenses	8,626	9,648	10,177
INCOME (LOSS) FROM OPERATIONS	(31)	382	(138)
OTHER INCOME (EXPENSE):			
Interest expense	(651)	(633)	(601)
Gains (losses) on investments	(71)	139	—
Gains on purchases or exchanges of debt	75	263	233
Other income	39	67	6
Total Other Expense	(608)	(164)	(362)
INCOME (LOSS) BEFORE INCOME TAXES	(639)	218	(500)
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	(26)	—	(9)
Deferred income taxes	(305)	(10)	11
Total Income Tax Expense (Benefit)	(331)	(10)	2
NET INCOME (LOSS)	(308)	228	(502)
Net income attributable to noncontrolling interests	—	(2)	(3)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(308)	226	(505)
Preferred stock dividends	(91)	(92)	(85)
Loss on exchange of preferred stock	(17)	—	(41)
Earnings allocated to participating securities	—	(1)	—
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (416)	$ 133	$ (631)
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ (0.25)	$ 0.15	$ (0.70)
Diluted	$ (0.25)	$ 0.15	$ (0.70)
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	1,665	909	906
Diluted	1,665	909	906

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,		
	2019	2018	2017
	($ in millions)		
NET INCOME (LOSS)	$ (308)	$ 228	$ (502)
OTHER COMPREHENSIVE INCOME, NET OF INCOME TAX:			
Unrealized gains (losses) on derivative instruments, net of income tax benefit of $0, $0, and $0	—	—	5
Reclassification of losses on settled derivative instruments, net of income tax expense of $0, $0 and $0	35	34	34
Other Comprehensive Income	35	34	39
COMPREHENSIVE INCOME (LOSS)	(273)	262	(463)
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	—	(2)	(3)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ (273)	$ 260	$ (466)

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,		
	2019	2018	2017
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ (308)	$ 228	$ (502)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	2,264	1,737	1,697
Deferred income tax expense (benefit)	(305)	(10)	11
Derivative (gains) losses, net	(3)	26	(409)
Cash receipts (payments) on derivative settlements, net	202	(345)	(18)
Stock-based compensation	30	32	49
(Gains) losses on sales of assets	(43)	264	(476)
Impairments	11	131	814
Exploration	49	96	214
(Gains) losses on investments	63	(139)	—
Gains on purchases or exchanges of debt	(79)	(263)	(235)
Other	(4)	(118)	(132)
(Increase) decrease in accounts receivable and other assets	376	16	(163)
(Decrease) increase in accounts payable, accrued liabilities and other	(630)	75	(375)
Net Cash Provided By Operating Activities	1,623	1,730	475
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and completion costs	(2,180)	(1,848)	(2,113)
Business combination, net	(353)	—	—
Acquisitions of proved and unproved properties	(35)	(128)	(88)
Proceeds from divestitures of proved and unproved properties	130	2,231	1,249
Additions to other property and equipment	(48)	(21)	(21)
Proceeds from sales of other property and equipment	6	147	55
Proceeds from sales of investments	—	74	—
Net Cash Provided By (Used In) Investing Activities	(2,480)	455	(918)

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

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

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from revolving credit facility borrowings	10,676	11,697	7,771
Payments on revolving credit facility borrowings	(10,180)	(12,059)	(6,990)
Proceeds from issuance of senior notes, net	108	1,236	1,585
Proceeds from issuance of term loan, net	1,455	—	—
Cash paid to purchase debt	(1,073)	(2,813)	(2,592)
Extinguishment of other financing	—	(122)	—
Cash paid for preferred stock dividends	(91)	(92)	(183)
Distributions to noncontrolling interest owners	(4)	(6)	(8)
Other	(32)	(27)	(17)
Net Cash Provided By (Used In) Financing Activities	859	(2,186)	(434)
Net increase (decrease) in cash and cash equivalents	2	(1)	(877)
Cash and cash equivalents, beginning of period	4	5	882
Cash and cash equivalents, end of period	$ 6	$ 4	$ 5

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

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
SUPPLEMENTAL CASH FLOW INFORMATION:			
Interest paid, net of capitalized interest	$ 691	$ 664	$ 667
Income taxes paid, net of refunds received	$ (6)	$ (3)	$ (16)
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Common stock issued for business combination	$ 2,037	$ —	$ —
Debt exchanged for common stock	$ 693	$ —	$ —
Preferred stock exchanged for common stock	$ 40	$ —	$ —
Change in senior notes exchanged	$ 971	$ —	$ —
Change in accrued drilling and completion costs	$ (19)	$ 174	$ 14
Acquisition of other property and equipment including assets under finance lease	$ —	$ 27	$ —

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,		
	2019	2018	2017
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 1,671	$ 1,671	$ 1,771
Exchange/conversions of 40,000, 0 and 236,048 shares of preferred stock for common stock	(40)	—	(100)
Balance, end of period	1,631	1,671	1,671
COMMON STOCK:			
Balance, beginning of period	9	9	9
Common shares issued for WildHorse Merger	7	—	—
Exchange of senior notes and convertible notes	3	—	—
Balance, end of period	19	9	9
ADDITIONAL PAID-IN CAPITAL:			
Balance, beginning of period	14,378	14,437	14,486
Common shares issued for WildHorse Merger	2,030	—	—
Stock-based compensation	27	33	54
Exchange of contingent convertible notes for 73,389,094, 0 and 0 shares of common stock	134	—	—
Exchange of senior notes for 235,563,519, 0 and 0 shares of common stock	438	—	—
Exchange of preferred stock for 10,367,950, 0, and 9,965,835 shares of common stock	40	—	100
Equity component of contingent convertible notes repurchased	(2)	—	(20)
Dividends on preferred stock	(91)	(92)	(183)
Balance, end of period	16,954	14,378	14,437
RETAINED EARNINGS (ACCUMULATED DEFICIT):			
Balance, beginning of period	(13,912)	(14,130)	(13,625)
Net income (loss) attributable to Chesapeake	(308)	226	(505)
Cumulative effect of change in accounting principle	—	(8)	—
Balance, end of period	(14,220)	(13,912)	(14,130)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(23)	(57)	(96)
Hedging activity	35	34	39
Balance, end of period	12	(23)	(57)

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,		
	2019	2018	2017
	($ in millions)		
TREASURY STOCK – COMMON:			
Balance, beginning of period	(31)	(31)	(27)
Purchase of 2,878,234, 1,510,022, and 1,206,419 shares for company benefit plans	(7)	(4)	(7)
Release of 879,795, 503,863 and 186,529 shares from company benefit plans	6	4	3
Balance, end of period	(32)	(31)	(31)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	4,364	2,092	1,899
NONCONTROLLING INTERESTS:			
Balance, beginning of period	41	44	49
Net income attributable to noncontrolling interests	—	2	3
Distributions to noncontrolling interest owners	(4)	(5)	(8)
Balance, end of period	37	41	44
TOTAL EQUITY	$ 4,401	$ 2,133	$ 1,943

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.

Recast Financial Information for Change in Accounting Principle

In the first quarter of 2019, we voluntarily changed our method of accounting for oil and natural gas exploration and development activities from the full cost method to the successful efforts method. Accordingly, financial information for prior periods presented herein has been recast to reflect retrospective application of the successful efforts method. Although the full cost method of accounting for oil and natural gas exploration and development activities continues to be an accepted alternative, the successful efforts method of accounting is the generally preferred method of the SEC and, because it is more widely used in the industry, we expect the change to improve the comparability of our financial statements to our peers. We also believe the successful efforts method provides a more representational depiction of assets and operating results and provides for our investments in oil and natural gas properties to be assessed for impairment in accordance with Accounting Standards Codification (ASC) Topic 360, *Property Plant and Equipment,* rather than valuations based on prices and costs prescribed under the full cost method as of the balance sheet date. For detailed information regarding the effects of the change to the successful efforts method, see Note 2.

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 11 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 11 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 9 for further discussion of our accounts receivable.

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas properties. Under this method, exploration costs such as exploratory geological and geophysical costs, expiration of unproved leasehold, delay rentals and exploration overhead are expensed as incurred. All costs related to production, general corporate overhead and similar activities are also expensed as incurred. All property acquisition costs and development costs are capitalized when incurred.

Exploratory drilling costs are initially capitalized, or suspended, pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. Costs of unsuccessful wells are charged to exploration expense. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If we determine that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. In some instances, this determination may take longer than one year. We review the status of all suspended exploratory drilling costs quarterly. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of oil and natural gas are capitalized.

Costs of drilling and equipping successful wells, costs to construct or acquire facilities, and associated asset retirement costs are depreciated using the unit-of-production (UOP) method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves.

Proceeds from the sales of individual oil and natural gas properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depreciation, depletion and amortization, if doing so does not materially impact the depletion rate of an amortization base. Generally, no gain or loss is recognized until an entire amortization base is sold. However, a gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

When circumstances indicate that the carrying value of proved oil and natural gas properties may not be recoverable, we compare unamortized capitalized costs to the expected undiscounted pre-tax future cash flows for the associated assets grouped at the lowest level for which identifiable cash flows are independent of cash flows of other assets. If the expected undiscounted pre-tax future cash flows, based on our estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized costs, the capitalized costs are reduced to fair value. Fair value is generally estimated using the income approach described in the ASC 820, *Fair Value Measurements*. If applicable, we utilize prices and other relevant information generated by market transactions involving assets and liabilities that are identical or comparable to the item being measured as the basis for determining fair value. The expected future cash flows used for impairment reviews and related fair value measurements are typically based on judgmental assessments of future production volumes, commodity prices, operating costs, and capital investment plans, considering all available information at the date of review. These assumptions are applied to develop future cash flow projections that are then discounted to estimated fair value, using a discount rate believed to be consistent with those applied by market participants. We have classified these fair value measurements as Level 3 in the fair value hierarchy.

Other Property and Equipment

Other property and equipment consists primarily of buildings and improvements, land, vehicles, computers, sand mine, natural gas compressors under finance 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, depletion and amortization in the consolidated statement of operations. Natural gas compressors under finance 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. See Note 17 for further discussion of other property and equipment.

Capitalized Interest

Interest from external borrowings is capitalized on significant investments in 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, 2019 and 2018 are liabilities of approximately $57 million and $104 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, 2019 and 2018, totaled $27 million and $30 million, respectively, and are being amortized over the life of the Chesapeake revolving credit facility using the straight-line method. Included in long-term debt are costs associated with the issuance of our senior notes. The remaining unamortized issuance costs as of December 31, 2019 and 2018, totaled $44 million and $53 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. See Note 6 for further discussion of litigation contingencies.

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. See Note 6 for discussion of environmental contingencies.

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 22 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. See Note 9 for further discussion of revenue recognition.

Fair Value Measurements

Certain financial instruments are reported on a recurring basis at fair value on our consolidated balance sheets. We also use fair value measurements on a nonrecurring basis when a qualitative assessment of our assets indicates a potential impairment. 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. See Note 15 for further discussion of fair value measurements.

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, 2019, 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 14 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 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 expense, oil, natural gas and NGL production expense, exploration expense, or marketing expense, based on the employees involved in those activities. See Note 12 for further discussion of share-based compensation.

Recently Issued Accounting Standards

In December 2019, the FASB issued Accounting Standards Update (ASU) 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes* (ASU 2019-12) as part of its initiative to reduce complexity in the accounting standards. The amendments in ASU 2019-12 remove certain exceptions related to the incremental approach for intraperiod tax allocation, the general methodology for calculating income taxes in an interim period and the recognition of deferred tax liabilities for outside basis differences. ASU 2019-12 also clarifies and simplifies other aspects of accounting for income taxes. The amendments in ASU 2019-12 become effective for us for the calendar year ending December 31, 2021; however, early adoption is permissible for periods for which financial statements have not yet been issued. We have decided to early adopt ASU 2019-12 for the calendar year ended December 31, 2019, which will be in effect from the beginning of the 2019 annual period. The early adoption of ASU 2019-12 did not result in a material impact to our balance sheet, results of operations or cash flows.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* ("ASC 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. As the implicit rate of the lease is not always readily determinable, the company uses its incremental borrowing rate to calculate the present value of lease payments based on information available at the commencement date. Operating ROU assets are included in other long-term assets while operating lease liabilities are included in other current and other long-term liabilities on the consolidated balance sheet. Finance ROU assets are reflected in total property and equipment, net, while finance lease liabilities are included in other current and other long-term liabilities on the consolidated balance sheet.

ASC 842 does 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 adopted the new standard on January 1, 2019 and as permitted by ASU 2018-11, *Leases (Topic 842): Targeted Improvements*, we did not adjust comparative-period financial statements and continued to apply the guidance in Topic 840, including its disclosure requirements, in the comparative periods presented prior to adoption. No cumulative-effect adjustment to retained earnings was required as a result of the modified retrospective approach.

Upon adoption of ASC 842, we made certain elections permitting us to not reassess: (1) whether any expired or existing contracts contained leases (2) the lease classification for any expired or existing leases, and (3) initial direct costs for any existing leases. Upon adoption of ASC 842, we also made an election permitting us to continue applying our current policy for land easements. The adoption of ASC 842 did not result in a material impact on our balance sheet, results of operations or cash flows.

Short-term leases will not be recognized on the balance sheet as an asset or a liability, and the related rental expense will be expensed as incurred. We have short-term lease agreements related to most of our drilling rig arrangements and some of our compressor rental arrangements.

See Note 8 for further information regarding leases.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2018 and 2017 to conform to the presentation used for the 2019 consolidated financial statements. In 2019, we have reclassified our presentation of ad valorem taxes to report the costs as a component of severance and ad valorem taxes in the accompanying consolidated statements of operations. Previously these costs were reflected as oil, natural gas and NGL production expenses. The net effect of this reclassification did not impact our previously reported net income, stockholders' equity or cash flows. The following table reflects the reclassifications made:

	Years Ended December 31,	
	2018	2017
	$ in millions	
Oil, natural gas and NGL production, previously reported	$ 539	$ 562
Reclassification of ad valorem taxes	(65)	(45)
Oil, natural gas and NGL production, as currently reported	$ 474	$ 517

The corresponding amounts have been reflected in severance and ad valorem taxes for 2018 and 2017 as shown below:

	Years Ended December 31,	
	2018	2017
	$ in millions	
Production taxes, previously reported	$ 124	$ 89
Reclassification of ad valorem taxes	65	45
Severance and ad valorem taxes, as currently reported	$ 189	$ 134

2. Change in Accounting Principle

In the first quarter of 2019, we voluntarily changed our method of accounting for oil and natural gas exploration and development activities from the full cost method to the successful efforts method. Accordingly, financial information for prior periods presented herein has been recast to reflect retrospective application of the successful efforts method. In general, under the successful efforts method, exploration costs such as exploratory dry holes, exploratory geophysical and geological costs, delay rentals, unproved leasehold impairments and exploration overhead are charged against earnings as incurred, versus being capitalized under the full cost method of accounting. The successful efforts method also provides for the assessment of potential property impairments by comparing the net carrying value of oil and natural gas properties to associated projected undiscounted pre-tax future net cash flows. If the expected undiscounted pre-tax future net cash flows are lower than the unamortized capitalized costs, the capitalized costs are reduced to fair value. Under the full cost method of accounting, a write-down would be required if the net carrying value of oil and natural gas properties exceeds a full cost ceiling using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months. In addition, gains or losses, if applicable, are generally recognized on the disposition of oil and natural gas property and equipment under the successful efforts method, as opposed to an adjustment to the net carrying value of the assets remaining under the full cost method. Our consolidated financial statements have been recast to reflect these differences.

The following tables present the effects of the change to the successful efforts method of accounting in the consolidated balance sheets:

	December 31, 2019		
CONSOLIDATED BALANCE SHEETS	**Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Proved oil and natural gas properties ($488 and $755 attributable to our VIE)	$ 75,148	$ (44,383)	$ 30,765
Unproved properties	$ 3,203	$ (1,030)	$ 2,173
Total Property and Equipment, at Cost	$ 80,161	$ (45,413)	$ 34,748
Less: accumulated depreciation, depletion and amortization (($468) and ($713) attributable to our VIE)	$ (66,626)	$ 46,624	$ (20,002)
Total Property and Equipment, Net	$ 13,545	$ 1,211	$ 14,756
Total Assets	$ 14,982	$ 1,211	$ 16,193
Other current liabilities	$ 1,377	$ 55	$ 1,432
Total Current Liabilities	$ 2,337	$ 55	$ 2,392
Other long-term liabilities	$ 116	$ 9	$ 125
Total Long-Term Liabilities	$ 9,391	$ 9	$ 9,400
Accumulated deficit	$ (15,451)	$ 1,231	$ (14,220)
Total Chesapeake Stockholders’ Equity	$ 3,133	$ 1,231	$ 4,364
Noncontrolling interests	$ 121	$ (84)	$ 37
Total Equity	$ 3,254	$ 1,147	$ 4,401
Total Liabilities and Equity	$ 14,982	$ 1,211	$ 16,193

	December 31, 2018		
CONSOLIDATED BALANCE SHEETS	**As Reported Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Proved oil and natural gas properties ($488 and $755 attributable to our VIE)	$ 69,642	$ (44,235)	$ 25,407
Unproved properties	$ 2,337	$ (776)	$ 1,561
Total Property and Equipment, at Cost	$ 73,700	$ (45,011)	$ 28,689
Less: accumulated depreciation, depletion and amortization (($461) and ($707) attributable to our VIE)	$ (64,685)	$ 46,799	$ (17,886)
Total Property and Equipment, Net	$ 9,030	$ 1,788	$ 10,818
Total Assets	$ 10,947	$ 1,788	$ 12,735
Other current liabilities	$ 1,540	$ 59	$ 1,599
Total Current Liabilities	$ 2,828	$ 59	$ 2,887
Other long-term liabilities	$ 156	$ 63	$ 219
Total Long-Term Liabilities	$ 7,652	$ 63	$ 7,715
Accumulated deficit	$ (15,660)	$ 1,748	$ (13,912)
Total Chesapeake Stockholders’ Equity	$ 344	$ 1,748	$ 2,092
Noncontrolling interests	$ 123	$ (82)	$ 41
Total Equity	$ 467	$ 1,666	$ 2,133
Total Liabilities and Equity	$ 10,947	$ 1,788	$ 12,735

The following tables present the effects of the change to the successful efforts method of accounting in the consolidated statements of operations:

	Year Ended December 31, 2019		
CONSOLIDATED STATEMENTS OF OPERATIONS	**Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Other revenues	$ —	$ 63	$ 63
Gain on sale of assets	$ —	$ 43	$ 43
Total revenues	$ 8,489	$ 106	$ 8,595
Exploration expense	$ —	$ 84	$ 84
General and administrative	$ 258	$ 57	$ 315
Depreciation, depletion and amortization	$ 1,616	$ 648	$ 2,264
Gain on sale of oil and natural gas properties	$ (15)	$ 15	$ —
Impairments	$ 344	$ (333)	$ 11
Other operating expense	$ 94	$ (2)	$ 92
Total operating expenses	$ 8,157	$ 469	$ 8,626
Income (loss) from operations	$ 332	$ (363)	$ (31)
Interest expense	$ (487)	$ (164)	$ (651)
Other income	$ 31	$ 8	$ 39
Total other expense	$ (452)	$ (156)	$ (608)
Loss before income taxes	$ (120)	$ (519)	$ (639)
Net income (loss)	$ 211	$ (519)	$ (308)
Net income attributable to noncontrolling interest	$ (2)	$ 2	$ —
Net income (loss) attributable to Chesapeake	$ 209	$ (517)	$ (308)
Net income (loss) available to common stockholders	$ 101	$ (517)	$ (416)
Earnings (loss) per common share basic	$ 0.06	$ (0.31)	$ (0.25)
Earnings (loss) per common share diluted	$ 0.06	$ (0.31)	$ (0.25)

	Year Ended December 31, 2018		
CONSOLIDATED STATEMENTS OF OPERATIONS	**As Reported Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Other revenues	$ —	$ 63	$ 63
Loss on sale of assets	$ —	$ (264)	$ (264)
Total revenues	$ 10,231	$ (201)	$ 10,030
Exploration expense	$ —	$ 162	$ 162
General and administrative	$ 280	$ 55	$ 335
Depreciation, depletion and amortization	$ 1,145	$ 592	$ 1,737
Loss on sale of oil and natural gas properties	$ 578	$ (578)	$ —
Impairments	$ 53	$ 78	$ 131
Other operating expenses	$ 10	$ (10)	$ —
Total operating expenses	$ 9,349	$ 299	$ 9,648
Income from operations	$ 882	$ (500)	$ 382
Interest expense	$ (487)	$ (146)	$ (633)
Other income	$ 70	$ (3)	$ 67
Total other expense	$ (15)	$ (149)	$ (164)
Income before income taxes	$ 867	$ (649)	$ 218
Net income	$ 877	$ (649)	$ 228
Net income attributable to noncontrolling interest	$ (4)	$ 2	$ (2)
Net income attributable to Chesapeake	$ 873	$ (647)	$ 226
Earnings allocated to participating securities	$ (6)	$ 5	$ (1)
Net income available to common stockholders	$ 775	$ (642)	$ 133
Earnings per common share basic	$ 0.85	$ (0.70)	$ 0.15
Earnings per common share diluted	$ 0.85	$ (0.70)	$ 0.15

	Year Ended December 31, 2017		
CONSOLIDATED STATEMENTS OF OPERATIONS	As Reported Under Full Cost	Adjustment	As Reported Under Successful Efforts
	($ in millions except per share data)		
Other revenues	$ —	$ 67	$ 67
Gain on sales of assets	$ —	$ 476	$ 476
Total revenues	$ 9,496	$ 543	$ 10,039
Exploration expense	$ —	$ 235	$ 235
General and administrative	$ 262	$ 71	$ 333
Depreciation, depletion and amortization	$ 995	$ 702	$ 1,697
Impairments	$ 5	$ 809	$ 814
Other operating expenses	$ 413	$ 3	$ 416
Total operating expenses	$ 8,357	$ 1,820	$ 10,177
Income (loss) from operations	$ 1,139	$ (1,277)	$ (138)
Interest expense	$ (426)	$ (175)	$ (601)
Other income	$ 9	$ (3)	$ 6
Total other expense	$ (184)	$ (178)	$ (362)
Income (loss) before income taxes	$ 955	$ (1,455)	$ (500)
Net income (loss)	$ 953	$ (1,455)	$ (502)
Net income attributable to noncontrolling interest	$ (4)	$ 1	$ (3)
Net income (loss) attributable to Chesapeake	$ 949	$ (1,454)	$ (505)
Earnings allocated to participating securities	$ (10)	$ 10	$ —
Net income (loss) available to common stockholders	$ 813	$ (1,444)	$ (631)
Earnings (loss) per common share basic	$ 0.90	$ (1.60)	$ (0.70)
Earnings (loss) per common share diluted	$ 0.90	$ (1.60)	$ (0.70)

The following tables present the effects of the change to the successful efforts method of accounting in the consolidated statements of comprehensive income:

	Year Ended December 31, 2019		
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME	**Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Net income (loss)	$ 211	$ (519)	$ (308)
Comprehensive income (loss)	$ 246	$ (519)	$ (273)
Comprehensive income attributable to noncontrolling interests	$ (2)	$ 2	$ —
Comprehensive income (loss) attributable to Chesapeake	$ 244	$ (517)	$ (273)

	Year Ended December 31, 2018		
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME	**As Reported Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Net income	$ 877	$ (649)	$ 228
Comprehensive income	$ 911	$ (649)	$ 262
Comprehensive income attributable to noncontrolling interests	$ (4)	$ 2	$ (2)
Comprehensive income attributable to Chesapeake	$ 907	$ (647)	$ 260

	Year Ended December 31, 2017		
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME	**As Reported Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Net income (loss)	$ 953	$ (1,455)	$ (502)
Comprehensive income (loss)	$ 992	$ (1,455)	$ (463)
Comprehensive income attributable to noncontrolling interests	$ (4)	$ 1	$ (3)
Comprehensive income (loss) attributable to Chesapeake	$ 988	$ (1,454)	$ (466)

The following tables present the effects of the change to the successful efforts method of accounting in the consolidated statements of cash flows:

CONSOLIDATED STATEMENTS OF CASH FLOWS	Year Ended December 31, 2019 Under Full Cost	Year Ended December 31, 2019 Adjustment	Year Ended December 31, 2019 As Reported Under Successful Efforts
	($ in millions except per share data)		
Net income (loss)	$ 211	$ (519)	$ (308)
Depreciation, depletion and amortization	$ 1,616	$ 648	$ 2,264
Gain on sale of oil and gas properties	$ (15)	$ 15	$ —
Gain on sales of assets	$ —	$ (43)	$ (43)
Impairments	$ 344	$ (333)	$ 11
Exploratory dry hole expense and leasehold impairments	$ —	$ 49	$ 49
Other	$ (2)	$ (2)	$ (4)
(Decrease) increase in accounts payable, accrued liabilities and other	$ (567)	$ (63)	$ (630)
Net cash provided by operating activities	$ 1,871	$ (248)	$ 1,623
Drilling and completion costs	$ (2,260)	$ 80	$ (2,180)
Acquisition of proved and unproved properties	$ (203)	$ 168	$ (35)
Net cash used by investing activities	$ (2,728)	$ 248	$ (2,480)

CONSOLIDATED STATEMENTS OF CASH FLOWS	Year Ended December 31, 2018 As Reported Under Full Cost	Year Ended December 31, 2018 Adjustment	Year Ended December 31, 2018 As Reported Under Successful Efforts
	($ in millions except per share data)		
Net income	$ 877	$ (649)	$ 228
Depreciation, depletion and amortization	$ 1,145	$ 592	$ 1,737
Loss on sale of oil and gas properties	$ 578	$ (578)	$ —
Losses on sales of assets	$ —	$ 264	$ 264
Impairments	$ 53	$ 78	$ 131
Exploratory dry hole expense and leasehold impairments	$ —	$ 96	$ 96
Other	$ (108)	$ (10)	$ (118)
Increase in accounts payable, accrued liabilities and other	$ 138	$ (63)	$ 75
Net cash provided by operating activities	$ 2,000	$ (270)	$ 1,730
Drilling and completion costs	$ (1,958)	$ 110	$ (1,848)
Acquisition of proved and unproved properties	$ (288)	$ 160	$ (128)
Net cash provided by investing activities	$ 185	$ 270	$ 455

	Year Ended December 31, 2017		
CONSOLIDATED STATEMENTS OF CASH FLOWS	**As Reported Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Net income (loss)	$ 953	$ (1,455)	$ (502)
Depreciation, depletion and amortization	$ 995	$ 702	$ 1,697
Gains on sales of assets	$ —	$ (476)	$ (476)
Impairments	$ 5	$ 809	$ 814
Exploratory dry hole expense and leasehold impairments	$ —	$ 214	$ 214
Other	$ (135)	$ 3	$ (132)
Decrease in accounts payable, accrued liabilities and other	$ (308)	$ (67)	$ (375)
Net cash provided by operating activities	$ 745	$ (270)	$ 475
Drilling and completion costs	$ (2,186)	$ 73	$ (2,113)
Acquisition of proved and unproved properties	$ (285)	$ 197	$ (88)
Net cash used in investing activities	$ (1,188)	$ 270	$ (918)

The following tables present the effects of the change to the successful efforts method of accounting in the consolidated statements of stockholders' equity:

	Year Ended December 31, 2019		
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY	**Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Accumulated deficit, beginning of period	$ (15,660)	$ 1,748	$ (13,912)
Net income (loss) attributable to Chesapeake	$ 209	$ (517)	$ (308)
Accumulated deficit, end of period	$ (15,451)	$ 1,231	$ (14,220)
Total Chesapeake stockholders' equity	$ 3,133	$ 1,231	$ 4,364
Noncontrolling interests, beginning of period	$ 123	$ (82)	$ 41
Net income attributable to noncontrolling interests	$ 2	$ (2)	$ —
Noncontrolling interests, end of period	$ 121	$ (84)	$ 37
Total equity	$ 3,254	$ 1,147	$ 4,401

	Year Ended December 31, 2018		
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY	**As Reported Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Accumulated deficit, beginning of period	$ (16,525)	$ 2,395	$ (14,130)
Net income attributable to Chesapeake	$ 873	$ (647)	$ 226
Accumulated deficit, end of period	$ (15,660)	$ 1,748	$ (13,912)
Total Chesapeake stockholders' equity	$ 344	$ 1,748	$ 2,092
Noncontrolling interests, beginning of period	$ 124	$ (80)	$ 44
Net income attributable to noncontrolling interests	$ 4	$ (2)	$ 2
Noncontrolling interests, end of period	$ 123	$ (82)	$ 41
Total equity	$ 467	$ 1,666	$ 2,133

	Year Ended December 31, 2017		
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY	**As Reported Under Full Cost**	**Adjustment**	**As Reported Under Successful Efforts**
	($ in millions except per share data)		
Accumulated deficit, beginning of period	$ (17,474)	$ 3,849	$ (13,625)
Net income (loss) attributable to Chesapeake	$ 949	$ (1,454)	$ (505)
Accumulated deficit, end of period	$ (16,525)	$ 2,395	$ (14,130)
Total Chesapeake stockholders' equity (deficit)	$ (496)	$ 2,395	$ 1,899
Noncontrolling interests, beginning of period	$ 128	$ (79)	$ 49
Net income attributable to noncontrolling interests	$ 4	$ (1)	$ 3
Noncontrolling interests, end of period	$ 124	$ (80)	$ 44
Total equity (deficit)	$ (372)	$ 2,315	$ 1,943

3. Oil and Natural Gas Property Transactions

WildHorse Acquisition

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 717.4 million shares of our common stock and $381 million in cash. We funded the cash portion of the consideration through borrowings under the Chesapeake revolving credit facility. In connection with the closing, we acquired all of WildHorse's debt. See Note 5 for additional information on the acquired debt.

Purchase Price Allocation

We have accounted for the acquisition of WildHorse and its corresponding merger (the "Merger") with and into our wholly owned subsidiary, Brazos Valley Longhorn, L.L.C. ("Brazos Valley Longhorn" or "BVL"), as a business combination, using the acquisition method. The following table represents the final allocation of the total purchase price of WildHorse to the identifiable assets acquired and the liabilities assumed based on the fair values as of the acquisition date.

	Purchase Price Allocation
	($ in millions)
Consideration:	
Cash	$ 381
Fair value of Chesapeake's common stock issued in the Merger [(a)]	2,037
Total consideration	$ 2,418
Fair Value of Liabilities Assumed:	
Current liabilities	$ 166
Long-term debt	1,379
Deferred tax liabilities	314
Other long-term liabilities	36
Amounts attributable to liabilities assumed	$ 1,895
Fair Value of Assets Acquired:	
Cash and cash equivalents	$ 28
Other current assets	128
Proved oil and natural gas properties	3,264
Unproved properties	756
Other property and equipment	77
Other long-term assets	60
Amounts attributable to assets acquired	$ 4,313
Total identifiable net assets	$ 2,418

(a) Based on 717,376,170 Chesapeake common shares issued at closing at $2.84 per share (closing price as of February 1, 2019).

The fair values of assets acquired and liabilities assumed were based on the following key inputs:

Oil and Natural Gas Properties

For the acquisition of WildHorse, we applied applicable guidance, under which an acquirer should recognize the identifiable assets acquired and the liabilities assumed on the acquisition date at fair value. The fair value estimate of proved and unproved oil and natural gas properties as of the acquisition date was based on estimated oil and natural gas reserves and related future net cash flows discounted using a weighted average cost of capital, including estimates of future production rates and future development costs. We utilized a combination of the NYMEX strip pricing and consensus pricing to value the reserves. Our estimates of commodity prices for purposes of determining discounted cash flows ranged from a 2019 price of $56.33 per barrel of oil increasing to a 2023 price of $61.17 per barrel of oil. Similarly, natural gas prices ranged from a 2019 price of $2.82 per mmbtu then increasing to a 2023 price of $3.00 per mmbtu. Both oil and natural gas commodity prices were held flat after 2023 and adjusted for inflation. We then applied various discount rates depending on the classification of reserves and other risk characteristics. Management utilized the assistance of a third-party valuation expert to estimate the value of the oil and natural gas properties acquired. Additionally, the estimated fair value estimate of proved and unproved oil and natural gas properties was corroborated by utilizing the market approach which considers recent comparable transactions for similar assets.

The inputs used to value oil and natural gas properties require significant judgment and estimates made by management and represent Level 3 inputs.

Financial Instruments and Other

The fair value measurements of long-term debt were estimated based on a market approach using estimates provided by an independent investment data services firm and represent Level 2 inputs.

Deferred Income Taxes

For federal income tax purposes, the WildHorse acquisition qualified as a tax-free merger, as a result, we acquired carryover tax basis in WildHorse's assets and liabilities. Deferred tax liabilities and assets were recorded for differences between the purchase price allocated to the assets acquired and liabilities assumed based on the fair value and the carryover tax basis. See Note 10 for further discussion of deferred income taxes.

WildHorse Revenues and Expenses Subsequent to Acquisition

We included in our consolidated statements of operations revenues of $752 million, direct operating expenses of $810 million, including depreciation, depletion and amortization, and other expense of $83 million related to the WildHorse business for the period from February 1, 2019 to December 31, 2019.

Pro Forma Financial Information

The following unaudited pro forma financial information for the years ended December 31, 2019 and 2018, respectively, is based on our historical consolidated financial statements adjusted to reflect as if the WildHorse acquisition had occurred on January 1, 2018. The information below reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including adjustments to conform the classification of expenses in WildHorse's statements of operations to our classification for similar expenses and the estimated tax impact of pro forma adjustments.

	Years Ended December 31,	
	2019	**2018**
	($ in millions except per share data)	
Revenues	$ 8,587	$ 11,211
Net income (loss) available to common stockholders	$ (431)	$ 195
Earnings (loss) per common share:		
Basic	$ (0.26)	$ 0.12
Diluted	$ (0.26)	$ 0.12

This unaudited pro forma information has been derived from historical information. The unaudited pro forma financial information is not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of the periods presented, nor is it necessarily indicative of future results.

2019 Transactions

In 2019, we received proceeds of approximately $130 million, net of post-closing adjustments, and recognized a gain of approximately $46 million, primarily for the sale of non-core oil and natural gas properties.

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 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. We recognized a loss of approximately $273 million associated with the transaction.

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. We recognized a gain of approximately $12 million associated with the transactions. 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, and recognized a gain of approximately $326 million. 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. Also, in 2017, 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.

4. 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 convertible senior notes did not have a dilutive effect and, therefore, were excluded from the calculation of diluted EPS.

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

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in millions)	
Common stock equivalent of our preferred stock outstanding	58	60	60
Common stock equivalent of our convertible senior notes outstanding	124	146	146
Common stock equivalent of our preferred stock outstanding prior to exchange	1	—	1
Participating securities	—	1	1

5. Debt

Our long-term debt consisted of the following as of December 31, 2019 and 2018:

	December 31, 2019		December 31, 2018	
	Principal Amount	Carrying Amount	Principal Amount	Carrying Amount
	($ in millions)			
Revolving credit facility	$ 1,590	$ 1,590	$ 419	$ 419
Term loan due 2024	1,500	1,470	—	—
11.5% senior secured second lien notes due 2025	2,330	3,248	—	—
Floating rate senior notes due 2019	—	—	380	380
6.625% senior notes due 2020[(a)]	208	208	437	437
6.875% senior notes due 2020	93	93	227	227
6.125% senior notes due 2021	167	167	548	548
5.375% senior notes due 2021	127	127	267	267
4.875% senior notes due 2022[(a)]	338	338	451	451
5.75% senior notes due 2023[(a)]	209	209	338	338
7.00% senior notes due 2024	624	624	850	850
6.875% senior notes due 2025[(b)]	2	2	—	—
8.00% senior notes due 2025	246	245	1,300	1,291
5.5% convertible senior notes due 2026[(c)(d)(e)]	1,064	765	1,250	866
7.5% senior notes due 2026	119	119	400	400
8.00% senior notes due 2026	46	44	—	—
8.00% senior notes due 2027	253	253	1,300	1,299
2.25% contingent convertible senior notes due 2038[(c)]	—	—	1	1
Debt issuance costs	—	(44)	—	(53)
Interest rate derivatives	—	—	—	1
Total debt, net	8,916	9,458	8,168	7,722
Less current maturities of long-term debt, net[(f)]	(385)	(385)	(381)	(381)
Total long-term debt, net	$ 8,531	$ 9,073	$ 7,787	$ 7,341

(a) In December 2019, we entered into a purchase and sale agreement to acquire $101 million principal amount of our 6.625% Senior Notes due 2020, 4.875% Senior Notes due 2022 and 5.75% Senior Notes due 2023. During the first quarter of 2020, we repurchased the senior notes.

(b) On February 1, 2019, we acquired the debt of WildHorse which consisted of 6.875% Senior Notes due 2025 and a revolving credit facility and in December 2019 we extinguished the debt with proceeds from a term loan issuance. See further discussion below.

(c) 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 5.5% Convertible Senior Notes due 2026 and our 2.25% Contingent Convertible Senior Notes due 2038 are 11.5% and 8.0%, respectively.

(d) 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 2019, 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 2020 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, 2019. 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 defined fundamental changes.

(e) The carrying amounts as of December 31, 2019 and 2018, are reflected net of discounts of $299 million and $384 million, respectively, associated with the equity component of our convertible senior notes. This amount is being amortized based on the effective yield method through the first demand repurchase date as applicable.

(f) As of December 31, 2019, net current maturities of long-term debt includes our 6.625% Senior Notes due August 2020 and our 6.875% Senior Notes due November 2020. 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)
2020	$ 385
2021	294
2022	289
2023	1,764
2024	2,124
Thereafter	4,060
Total	$ 8,916

Debt Issuances and Retirements 2019

Term Loan. In December 2019, we entered into a secured 4.5-year term loan facility in an aggregate principal amount of $1.5 billion for net proceeds of approximately $1.455 billion. Our obligations under the new facility are unconditionally guaranteed on a joint and several basis by the same subsidiaries that guarantee our revolving credit facility and second lien notes (including BVL and its subsidiaries) and are secured by first-priority liens on the same collateral securing our revolving credit facility (with a position in the collateral proceeds waterfall junior to the revolving credit facility). The term loan bears interest at a rate of London Interbank Offered Rate (LIBOR) plus 8.00% per annum, subject to a 1.00% LIBOR floor, or the Alternative Base Rate (ABR) plus 7.00% per annum, subject to a 2.00% ABR floor, at our option. The loan was made at 98% of par. We used the net proceeds to finance tender offers for our unsecured BVL senior notes and to repay amounts outstanding under our BVL revolving credit facility. We recorded an aggregate net gain of approximately $4 million associated with the retirement of our BVL senior notes and the BVL revolving credit facility.

The term loan matures in June 2024 and voluntary prepayments are subject to a make-whole premium prior to the 18-month anniversary of the closing of the term loan, a premium to par of 5.00% from the 18-month anniversary until but excluding the 30-month anniversary, a premium to par of 2.5% from the 30-month anniversary until but excluding the 42-month anniversary and at par beginning on the 42-month anniversary. The term loan may be subject to mandatory prepayments and offers to prepay with net cash proceeds of certain issuances of debt, certain asset sales and other dispositions of collateral and upon a change of control.

The term loan contains covenants limiting our ability to incur additional indebtedness, incur liens, consummate mergers and similar fundamental changes, make restricted payments, sell collateral and use proceeds from such sales, make investments, repay certain subordinate, unsecured or junior lien indebtedness, and enter into transactions with affiliates.

Events of default under the term loan include, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; cross-payment default and cross acceleration with respect to other indebtedness with an outstanding principal balance of $125 million or more; bankruptcy; judgments involving liability of $125 million or more that are not paid; and ERISA events. Many events of default are subject to customary notice and cure periods.

Senior Secured Second Lien Notes. In December 2019, we completed private offers to exchange newly issued 11.5% Senior Secured Second Lien Notes due 2025 (the “Second Lien Notes”) for the following outstanding senior unsecured notes (the “Existing Notes”):

	Notes Exchanged ($ in millions)
7.00% senior notes due 2024	$ 226
8.00% senior notes due 2025	999
8.00% senior notes due 2026	873
7.5% senior notes due 2026	281
8.00% senior notes due 2027	837
Total	$ 3,216

The Second Lien Notes are secured second lien obligations and are contractually junior to our current and future secured first lien indebtedness, including indebtedness incurred under our revolving credit facility and term loan facility, to the extent of the value of the collateral securing such indebtedness, effectively senior to all of our existing and future unsecured indebtedness, including our outstanding senior notes, to the extent of the value of the collateral, and senior to any future subordinated indebtedness that we may incur. We have the option to redeem the Second Lien Notes, in whole or in part, at specified make-whole or redemption prices. Our Second Lien Notes are governed by an indenture containing covenants that may limit our ability and our subsidiaries’ ability to create liens securing certain indebtedness, make certain restricted payments, enter into certain sale-leaseback transactions, consolidate, merge or transfer assets and dispose of certain collateral and use proceeds from dispositions of certain collateral. As a holding company, Chesapeake owns no operating assets and has no significant operations independent of its subsidiaries. Chesapeake’s obligations under the Second Lien Notes are jointly and severally, fully and unconditionally guaranteed by the same subsidiaries that guarantee our revolving credit facility and term loan facility (including BVL and its subsidiaries). See Note 25 for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries.

The exchanges of the Existing Notes (with a carrying value of $3.152 billion) for $2.210 billion of Second Lien Notes, were accounted for as a troubled debt restructuring (“TDR”). For the majority of the notes in this exchange, the future undiscounted cash flows were greater than the net carrying value of the original debt, no gain was recognized and a new effective interest rate was established based on the carrying value of the original debt. The amount of the extinguished debt will be amortized over the life of the notes as a reduction to interest expense. As a result, our reported interest expense will be significantly less than the contractual interest payments throughout the term of the Second Lien Notes.

In a subsequent transaction in December 2019, we issued an additional $120 million of 11.5% Senior Secured Second Lien Notes due 2025 pursuant to a private offering, at 89.75% of par. Additionally, in December 2019, we entered into a purchase and sale agreement with the same counterparty to acquire $101 million principal amount of our 6.625% Senior Notes due 2020, 4.875% Senior Notes due 2022 and 5.75% Senior Notes due 2023 at a discount. During the first quarter of 2020, we repurchased the senior notes.

Exchanges of Senior Notes for Common Stock. We privately negotiated exchanges of approximately $507 million principal amount of our outstanding senior notes for 235,563,519 shares of common stock and $186 million principal amount of our outstanding convertible senior notes for 73,389,094 shares of common stock. We recorded an aggregate net gain of approximately $64 million associated with the exchanges.

We issued at par approximately $919 million of 8.00% Senior Notes due 2026 (“2026 notes”) pursuant to a private exchange offer for the following outstanding senior unsecured notes:

	Notes Exchanged ($ in millions)	
6.625% senior notes due 2020	$	229
6.875% senior notes due 2020		134
6.125% senior notes due 2021		381
5.375% senior notes due 2021		140
Total	$	884

We may redeem some or all of the 2026 notes at any time prior to March 15, 2022 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 March 15, 2022, 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 2026 notes at any time on or after March 15, 2022 at the redemption prices in accordance with the terms of the notes, 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 all of our wholly owned subsidiaries that guarantee the Chesapeake revolving credit facility and certain other unsecured senior notes. We accounted for the exchange as a modification to existing debt and no gain or loss was recognized.

We repaid upon maturity $380 million principal amount of our Floating Rate Senior Notes due April 2019 with borrowings from our Chesapeake revolving credit facility.

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.

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 25 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.

Revolving Credit Facility

Our revolving credit facility matures in September 2023 and the current aggregate commitment of the lenders and borrowing base under the facility is $3.0 billion. The 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. Scheduled borrowing base redeterminations will continue to occur semiannually. Our next borrowing base redetermination is scheduled for the second quarter of 2020. As of December 31, 2019, we had outstanding borrowings of $1.590 billion under our revolving credit facility and had used $59 million for various letters of credit.

Borrowings under our revolving credit facility bear interest at an alternative base rate (ABR) or LIBOR, at our election, plus an applicable margin ranging from 1.50%-2.50% per annum for ABR loans and 2.50%-3.50% per annum for LIBOR loans, depending on the percentage of the borrowing base then being utilized.

Our 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.

On December 3, 2019, we entered into the second amendment to our credit agreement. Among other things, the amendment (i) permitted the issuance of certain secured indebtedness with a lien priority or proceeds recovery behind the obligations under the credit agreement without a corresponding 25% reduction in the borrowing base under the credit agreement, if issued by the next scheduled redetermination of the borrowing base, (ii) increased the amount of indebtedness that can be secured on a pari passu first-lien basis with (and with recovery proceeds behind) the obligations under the credit agreement from $1 billion to $1.5 billion, (iii) increased the applicable margin as defined in the credit agreement on borrowings under the credit agreement by 100 basis points, (iv) requires liquidity of at least $250 million at all times, (v) for each fiscal quarter commencing with the fiscal quarter ending December 31, 2019, replaced the secured leverage ratio financial covenant with a requirement that the first lien secured leverage ratio not exceed 2.50 to 1 as of the end of such fiscal quarter, (vi) increased the maximum permitted leverage ratio as of the end of each fiscal quarter to 4.50 to1 through the fiscal quarter ending December 31, 2021, with step-downs to 4.25 to 1 for the fiscal quarter ending March 31, 2022 and to 4.00 to 1 for each fiscal quarter ending thereafter, and (vii) required that we use the aggregate net cash proceeds of certain asset sales in excess of $50 million to prepay certain indebtedness and/or reduce commitments under our credit agreement, until the retirement of all of our senior notes maturing before September 12, 2023. On December 26, 2019, we entered into the third amendment to our credit agreement, which, among other things, permitted the issuance of certain secured indebtedness with a lien priority behind the obligations under the credit agreement without a corresponding 25% reduction in the borrowing base under the credit agreement, if issued by December 31, 2019 and issued in exchange for, or the proceeds used to refinance, our senior notes.

As of December 31, 2019, 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 our revolving credit facility.

Phase-Out of LIBOR

In July 2017, the UK's Financial Conduct Authority, which regulates LIBOR, announced that it intends to phase out LIBOR as a benchmark by the end of 2021. At the present time, our revolving credit facility and our term loan have terms that extend beyond 2021. Our revolving credit facility and our term loan each provide for a mechanism to amend the underlying agreements to reflect the establishment of an alternate rate of interest upon the occurrence of certain events related to the phase-out of LIBOR. However, we have not yet pursued any technical amendment or other contractual alternative to our revolving credit facility or term loan to address this matter. We are currently evaluating the potential impact of the eventual replacement of the LIBOR interest rate.

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, 2019		December 31, 2018	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Short-term debt (Level 1)	$ 385	$ 360	$ 381	$ 379
Long-term debt (Level 1)	$ 753	$ 622	$ 3,495	$ 3,173
Long-term debt (Level 2)	$ 8,320	$ 6,085	$ 3,846	$ 3,644

6. 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.

We and other natural gas producers have been named in various lawsuits alleging underpayment of royalties and other shares of the proceeds of production. 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 amounts owed 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 payment practices, pre-and post-judgment interest, and attorney's fees and costs. Plaintiffs have varying 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 or other shares of the proceeds of production 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. We intend to vigorously defend these claims.

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 $36 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.

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. We intend to vigorously defend these claims.

We previously disclosed ongoing discussions between our subsidiary, Chesapeake Appalachia, L.L.C. ("CALLC") and the Pennsylvania Department of Environmental Protection related to gas migration in the vicinity of certain of our wells in Bradford County. Those concerns were resolved by the parties on August 28, 2019. Pursuant to the settlement, CALLC paid a civil penalty of less than $100,000.

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

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, 2019
	($ in millions)
2020	$ 1,136
2021	1,033
2022	913
2023	789
2024	690
2025 – 2034	3,479
Total	$ 8,040

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 contracts with third-party contractors to provide maintenance and other services to generators and natural gas compressors. These commitments are not recorded as an obligation in the accompanying consolidated balance sheets. The aggregate undiscounted minimum future payments under these service contracts are detailed below.

	December 31, 2019
	($ in millions)
2020	$ 7
2021	7
2022	2
Total	$ 16

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.

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.

7. Other Liabilities

Other current liabilities as of December 31, 2019 and 2018 are detailed below:

	December 31,	
	2019	2018
	($ in millions)	
Revenues and royalties due others	$ 516	$ 687
Accrued drilling and production costs	326	258
Joint interest prepayments received	52	73
VPP deferred revenue[a]	55	59
Accrued compensation and benefits	156	202
Other accrued taxes	150	108
Other	177	212
Total other current liabilities	$ 1,432	$ 1,599

Other long-term liabilities as of December 31, 2019 and 2018 are detailed below:

	December 31,	
	2019	2018
	($ in millions)	
VPP deferred revenue[a]	$ 9	$ 63
Unrecognized tax benefits[b]	—	53
Other	116	103
Total other long-term liabilities	$ 125	$ 219

(a) At the inception of our volumetric production payment (VPP) agreements, we (i) removed the proved reserves associated with the VPP, (ii) recognized VPP proceeds as deferred revenue which are being amortized on a unit-of-production basis to other revenue over the term of the VPP, (iii) retained responsibility for the production costs and capital costs related to VPP interests and (iv) ceased recognizing production associated with the VPP volumes. The remaining deferred revenue balance will be recognized in other revenues in the consolidated statement of operations through February 2021, assuming the related VPP production volumes are delivered as scheduled.

(b) The liability for unrecognized tax benefits was eliminated during the fourth quarter of 2019 as a result of a settlement.

8. Leases

We are a lessee under various agreements for compressors, office space, vehicles and other equipment. As of December 31, 2019, these leases have remaining terms ranging from one month to seven years. Certain of our lease agreements include options to renew the lease, terminate the lease early or purchase the underlying asset at the end of the lease. We determine the lease term at the lease commencement date as the non-cancelable period of the lease, including options to extend or terminate the lease when we are reasonably certain to exercise the option. The company's vehicles are the only leases with renewal options that we are reasonably certain to exercise. The renewals are reflected in the ROU asset and lease liability balances.

Upon adoption of ASC 842 on January 1, 2019, we recognized a nominal operating lease liability and a nominal related ROU asset related to vehicles we lease.

On February 1, 2019, we acquired WildHorse and, as part of the purchase price allocation, we recognized additional operating lease liabilities of $40 million, a related ROU asset of $38 million, and lease incentives of $2 million related to two office space leases, a long-term hydraulic fracturing agreement and other equipment leases. Regarding our long-term hydraulic fracturing agreements, we made a policy election to treat both lease and non-lease components as a single lease component.

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 lease is accounted for as a finance lease liability.

The following table presents our ROU assets and lease liabilities as of December 31, 2019.

	Finance	Operating
	($ in millions)	
ROU assets	$ 17	$ 22
Lease liabilities:		
Current lease liabilities	$ 9	$ 9
Long-term lease liabilities	9	16
Total lease liabilities	$ 18	$ 25

Additional information for the Company's operating and finance leases is presented below:

	Year Ended December 31, 2019	
Lease cost:	($ in millions)	
Amortization of ROU assets	$	8
Interest on lease liability		2
Finance lease cost		10
Operating lease cost		26
Short-term lease cost		112
Total lease cost	$	148
Other information:		
Operating cash outflows from finance lease	$	2
Operating cash outflows from operating leases	$	11
Investing cash outflows from operating leases	$	127
Financing cash outflows from finance lease	$	8
Weighted average remaining lease term - finance lease		2.00 years
Weighted average remaining lease term - operating leases		4.65 years
Weighted average discount rate - finance lease		7.50%
Weighted average discount rate - operating leases		4.85%

Maturity analysis of finance lease liabilities and operating lease liabilities are presented below:

	December 31, 2019	
	Finance Lease	Operating Leases
	($ in millions)	
2020	$ 10	$ 10
2021	10	5
2022	—	4
2023	—	2
2024	—	2
Thereafter	—	5
Total lease payments	20	28
Less imputed interest	(2)	(3)
Present value of lease liabilities	18	25
Less current maturities	(9)	(9)
Present value of lease liabilities, less current maturities	$ 9	$ 16

The aggregate undiscounted minimum future lease payments under previous lease accounting standard, ASC 840, are presented below:

	December 31, 2018	
	Capital Lease	Operating Leases
	($ in millions)	
2019	$ 10	$ 3
2020	10	1
2021	10	—
Total minimum lease payments	$ 30	$ 4

9. 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.

The following table shows revenue disaggregated by operating area and product type, for the years ended December 31, 2019 and 2018:

	Year Ended December 31, 2019			
	Oil	Natural Gas	NGL	Total
	($ in millions)			
Marcellus	$ —	$ 856	$ —	$ 856
Haynesville	—	620	—	620
Eagle Ford	1,289	153	119	1,561
Brazos Valley	721	32	16	769
Powder River Basin	369	77	32	478
Mid-Continent	164	44	25	233
Revenue from contracts with customers	2,543	1,782	192	4,517
Gains (losses) on oil, natural gas and NGL derivatives	(212)	217	—	5
Oil, natural gas and NGL revenue	$ 2,331	$ 1,999	$ 192	$ 4,522
Marketing revenue from contracts with customers	$ 2,473	$ 900	$ 246	$ 3,619
Other marketing revenue	311	41	—	352
Losses on marketing derivatives	—	(4)	—	(4)
Marketing revenue	$ 2,784	$ 937	$ 246	$ 3,967

	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	222	—	679
Gains on marketing derivatives	—	7	—	7
Marketing revenue	$ 3,197	$ 1,423	$ 456	$ 5,076

Accounts Receivable

Accounts receivable as of December 31, 2019 and 2018 are detailed below:

	December 31, 2019	December 31, 2018
	($ in millions)	
Oil, natural gas and NGL sales	$ 737	$ 976
Joint interest billings	200	211
Other	74	77
Allowance for doubtful accounts	(21)	(17)
Total accounts receivable, net	$ 990	$ 1,247

10. Income Taxes

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

	Years Ended December 31, 2019	2018	2017
	($ in millions)		
Current			
Federal	$ —	$ —	$ (14)
State	(26)	—	5
Current Income Taxes	(26)	—	(9)
Deferred			
Federal	(297)	3	13
State	(8)	(13)	(2)
Deferred Income Taxes	(305)	(10)	11
Total	$ (331)	$ (10)	$ 2

The income tax expense (benefit) reported in our consolidated statement of operations is different from the federal income tax expense (benefit) computed using the federal statutory rate for the following reasons:

	Years Ended December 31, 2019	2018	2017
	($ in millions)		
Income tax expense (benefit) at the federal statutory rate (21%, 21%, 35%)	$ (134)	$ 45	$ (175)
State income taxes (net of federal income tax benefit)	(21)	27	5
Partial release of valuation allowance due to the WildHorse Merger	(314)	—	—
Remeasurement of deferred tax assets and liabilities	—	—	931
Change in valuation allowance excluding impact of WildHorse Merger	114	(97)	(771)
Other	24	15	12
Total	$ (331)	$ (10)	$ 2

We applied the guidance in SAB 118 when accounting for the enactment-date effect of 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”). 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 had completed our accounting for all of the enactment-date income tax effects of the Tax Act. The adjustments made during 2018 were considered immaterial but nevertheless are included as a component of income tax expense (benefit) 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 position.

We reassessed the realizability of our deferred tax assets and continue to maintain a full valuation allowance against our net deferred tax asset positions for federal and state purposes with the exception of Texas. Texas is currently in a net deferred tax liability position. Of the $206 million net decrease in our valuation allowance, $200 million is reflected as a component of income tax benefit in our consolidated statement of operations for the year ended December 31, 2019. This decrease in the valuation allowance is primarily due to the partial release of the valuation allowance associated with the WildHorse Merger.

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, NOL carryforwards and disallowed business interest carryforwards that comprise our deferred income taxes are as follows:

	December 31,	
	2019	**2018**
	($ in millions)	
Deferred tax liabilities:		
Property, plant and equipment	$ (546)	$ (976)
Volumetric production payments	(89)	(86)
Carrying value of debt	—	(95)
Derivative instruments	(14)	(56)
Other	(5)	(7)
Deferred tax liabilities	(654)	(1,220)
Deferred tax assets:		
Net operating loss carryforwards	1,971	2,737
Carrying value of debt	169	—
Disallowed business interest carryforward	25	194
Asset retirement obligations	50	40
Investments	83	111
Accrued liabilities	64	89
Other	87	60
Deferred tax assets	2,449	3,231
Valuation allowance	(1,805)	(2,011)
Deferred tax assets after valuation allowance	644	1,220
Net deferred tax liability	$ (10)	$ —

As of December 31, 2019, we had federal NOL carryforwards of approximately $7.582 billion and state NOL carryforwards of approximately $6.844 billion. The associated deferred tax assets related to these federal and state NOL carryforwards were $1.592 billion and $379 million, respectively. The federal NOL carryforwards generated in tax years prior to 2018 expire between 2033 and 2037. As a result of the Tax Act, the 2018 federal NOL carryforward has no expiration. The value of all of these carryforwards depends on our ability to generate future taxable income.

As of December 31, 2019, and 2018, we had deferred tax assets of $2.449 billion and $3.231 billion upon which we had a valuation allowance of $1.805 billion and $2.011 billion, respectively. Of the net change in the valuation allowance of $206 million for both federal and state deferred tax assets, $200 million is reflected as a component of income tax benefit 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 carryforwards, 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, 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, 2019. Such objective negative evidence limits our ability to consider various forms of subjective positive evidence, such as any projections for future income. Accordingly, management has not changed its judgment for the period ended December 31, 2019 with respect to the need for a full valuation allowance against our net deferred tax asset positions for federal and state purposes with the exception of Texas. Texas is currently in a net deferred tax liability position. The amount of the deferred tax assets 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. Should we return to a level of sustained profitability, 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.

On February 1, 2019, we completed the acquisition of WildHorse. For federal income tax purposes, the transaction qualified as a tax-free merger under Section 368 of the Code and, as a result, we acquired carryover tax basis in WildHorse’s assets and liabilities. We recorded a net deferred tax liability of $314 million as part of the business combination accounting for WildHorse. As a consequence of maintaining a full valuation allowance against our net deferred tax asset positions (federal and state), a partial release of the valuation allowance was recorded as a discrete income tax benefit of $314 million through the consolidated statement of operations in the first quarter of 2019. The net deferred tax liability determined through business combination accounting includes deferred tax liabilities on plant, property and equipment and prepaid compensation totaling $401 million, partially offset by deferred tax assets totaling $87 million relating to federal NOL carryforwards, disallowed business interest carryforwards and certain other deferred tax assets. These carryforwards will be subject to an annual limitation under Section 382 of the Code of approximately $61 million. We determined that no separate valuation allowances were required to be established through business combination accounting against any of the individual deferred tax assets acquired.

Our ability to utilize NOL carryforwards, disallowed business interest 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 subject to an annual limitation under Section 382 of the Code should transactions involving our equity, including issuances of our stock or the sale or exchange of our stock by certain shareholders, result in an Ownership Change. (For this purpose, “stock” includes certain preferred stock). Some states impose similar limitations on tax attribute utilization upon experiencing an Ownership Change.

As of December 31, 2019, we do not believe that an Ownership Change has occurred that would subject us to an annual limitation on the utilization of our NOL carryforwards, disallowed business interest carryforwards and other tax attributes. After taking into account the exchanges of our common stock for certain outstanding senior notes that occurred during the quarter ended September 30, 2019 (see Note 5 for further details of the debt exchanges) and the exchange of our common stock for certain Cumulative Convertible Preferred Stock which also occurred during the quarter ended September 30, 2019 (see Note 11 for further details of the stock exchange), our cumulative shift remains under 50% but has increased to a level of over 40%. Therefore, with the exception of the NOL carryforwards and disallowed business interest carryforwards acquired upon the WildHorse Merger, we do not believe we have a limitation on the ability to utilize our carryforwards and other tax attributes under Section 382 of the Code as of December 31, 2019. However, future transactions involving our equity, including relatively small transactions and transactions beyond our control, could cause an Ownership Change and therefore an annual limitation on the utilization of NOL carryforwards, disallowed business interest carryforwards and possibly other tax attributes.

Further, the Proposed Regulations would, if finalized in their current form, significantly reduce our annual limitation should we experience an Ownership Change on or after the date the Proposed Regulations become final and we are in a net unrealized built-in gain position. Among other changes, the Proposed Regulations would, if finalized in their current form, limit the potential increases to the annual limitation amount associated with certain built-in gains existing at the time of an Ownership Change, thereby significantly reducing the ability to utilize tax attributes. As a result, certain

NOL carryforwards, disallowed business interest carryforwards and other tax attributes may need to be written off or have a valuation allowance maintained against them possibly leading to a material charge to income tax expense.

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, 2019, and 2018, the amount of unrecognized tax benefits related to NOL carryforwards and tax liabilities associated with uncertain tax positions was $74 million and $79 million, respectively. Of the 2019 amount, $29 million is related to state tax receivables not expected to be recovered and the remainder is related to NOL carryforwards. 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. If recognized, $29 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, 2019, we had no amounts accrued for interest related to these uncertain tax positions. As of December 31, 2018, we had accrued liabilities of $20 million for interest. 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:

	2019	2018	2017
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 79	$ 106	$ 202
Additions based on tax positions related to the current year	—	—	—
Additions to tax positions of prior years	27	—	4
Settlements	(32)	—	(100)
Expiration of the applicable statute of limitations	—	(23)	—
Reductions to tax positions of prior years	—	(4)	—
Unrecognized tax benefits at end of period	$ 74	$ 79	$ 106

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 NOL carryforwards upon utilization. Our tax years 2016 through 2018 remain open for all purposes of examination by the IRS. With respect to WildHorse, the federal income tax returns for tax years 2016 through 2018 as well as the short period return January 1, 2019 through February 1, 2019, remain open for examination by the IRS. The IRS has notified us that our 2016 income tax return as well as the WildHorse 2017 income tax return will be audited.

In addition, tax years 2016 through 2018 as well as certain earlier years remain open for examination by state tax authorities including the WildHorse state income tax returns for such periods along with the WildHorse 2019 short period return. 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 financial position or results of operations.

11. Equity

Common Stock

A summary of the changes in our common shares issued for the years ended December 31, 2019, 2018 and 2017 is detailed below:

	Years Ended December 31,		
	2019	2018	2017
	(in thousands)		
Shares issued as of January 1	913,716	908,733	896,279
Common shares issued for WildHorse Merger[a]	717,376	—	—
Exchange of senior notes[b]	235,564	—	—
Exchange of convertible notes[b]	73,389	—	—
Exchange of preferred stock	10,368	—	9,966
Restricted stock issuances (net of forfeitures and cancellations)[c]	4,146	4,983	2,488
Shares issued as of December 31	1,954,559	913,716	908,733

(a) See Note 3 for discussion of WildHorse Merger.

(b) See Note 5 for discussion of debt exchanges.

(c) See Note 12 for discussion of restricted stock.

During the year ended December 31, 2019, our shareholders approved a proposal to amend our restated certificate of incorporation to increase the number of authorized shares of our common stock from 2,000,000,000 shares to 3,000,000,000 shares.

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2019:

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, 2019, 2018 and 2017 are detailed below:

	5.75%	5.75% (Series A)	4.50%	5.00% (Series 2005B)
	(in thousands)			
Shares outstanding as of January 1, 2019	770	463	2,559	1,811
Preferred stock exchanges[(a)]	—	(40)	—	—
Shares outstanding as of December 31, 2019	770	423	2,559	1,811
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 exchanges[(b)]	(73)	(13)	—	(151)
Shares outstanding as of December 31, 2017	770	463	2,559	1,811

(a) During 2019, we exchanged 10,367,950 shares of common stock for 40,000 shares of our 5.75% (Series A) Cumulative Convertible Preferred Stock. In connection with the exchange, 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 $17 million is reflected as a reduction to net income available to common stockholders for the purpose of calculating earnings per common share.

(b) 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.

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, 2019 and 2018, changes in accumulated other comprehensive income (loss) for cash flow hedges, net of tax, are detailed below:

	Years Ended December 31,	
	2019	2018
	($ in millions)	
Balance, as of January 1	$ (23)	$ (57)
Amounts reclassified from accumulated other comprehensive income[a]	35	34
Balance, as of December 31	$ 12	$ (23)

(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, 2019, and 2018, we had $37 million and $41 million, respectively, of noncontrolling interests on our consolidated balance sheets attributable to the Trust. There was nominal net income attributable to the Trust's noncontrolling interest in 2019. Net income attributable to the Trust's noncontrolling interest was $2 million and $3 million for the years ended December 31, 2018 and 2017, respectively.

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.

12. 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, 2019, 29,865,514 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 2019, 2018 and 2017 is presented below:

	Shares of Unvested Restricted Stock	Weighted Average Grant Date Fair Value
	(in thousands)	
Unvested restricted stock as of January 1, 2019	11,858	$ 4.43
Granted	5,908	$ 2.65
Vested	(5,944)	$ 4.38
Forfeited	(1,380)	$ 3.72
Unvested restricted stock as of December 31, 2019	10,442	$ 3.55
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

The aggregate intrinsic value of restricted stock that vested during 2019 was approximately $15 million based on the stock price at the time of vesting.

As of December 31, 2019, there was approximately $19 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 1.92 years.

Stock Options. In 2019, 2018 and 2017, 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 2019:

Expected option life – years	6.0
Volatility	65.61%
Risk-free interest rate	2.47%
Dividend yield	—%

The following table provides information related to stock option activity for 2019, 2018 and 2017:

	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, 2019	18,096	$ 7.20	7.15	$ —
Granted	1,000	$ 2.97		
Exercised	—	$ —		$ —
Expired	(553)	$ 6.36		
Forfeited	(609)	$ 3.97		
Outstanding as of December 31, 2019	17,934	$ 7.10	5.70	$ —
Exercisable as of December 31, 2019	13,092	$ 8.28	4.86	$ —
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	$ —

(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, 2019, there was $5 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 1.23 years, net of actual forfeitures.

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, 2019, 2018 and 2017:

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
General and administrative expenses	$ 26	$ 31	$ 43
Oil and natural gas properties	2	2	5
Oil, natural gas and NGL production expenses	3	5	12
Exploration expenses	1	1	1
Total restricted stock and stock option compensation	$ 32	$ 39	$ 61

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, 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 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. The performance period for the 2017 awards ended on December 31, 2019.

For PSUs granted in 2018 and 2019, 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%. For the 2019 award, EBITDA and capital expenditures will be adjusted for changes resulting from our conversion from the full cost method of accounting to the successful efforts method. 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 performance 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 the vesting period.

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

	Units	Grant Date Fair Value	December 31, 2019 Fair Value	December 31, 2019 Vested Liability
		($ in millions)	($ in millions)	
2019 PSU Awards:				
Payable 2020, 2021 and 2022	4,674,503	$ 14	$ 4	$ —
2018 PSU Awards:				
Payable 2020 and 2021	2,340,157	$ 7	$ 2	$ —
2017 PSU Awards:				
Payable 2020	1,174,973	$ 8	$ 1	$ —
2018 CRSU Awards:				
Payable 2020 and 2021	8,233,207	$ 25	$ 7	$ —

We recognized the following compensation costs (credits), net of actual forfeitures, related to our liability-classified awards for the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31, 2019	2018	2017
	($ in millions)		
General and administrative expenses	$ 5	$ 9	$ (4)
Oil and natural gas properties	1	1	—
Oil, natural gas and NGL production expenses	3	2	—
Restructuring and other termination costs	1	—	—
Total liability-classified awards compensation	$ 10	$ 12	$ (4)

13. 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 $29 million, $31 million and $35 million to the 401(k) Plan in 2019, 2018 and 2017, respectively.

We also maintained a nonqualified deferred compensation plan (DC Plan) which we terminated in January 2020 in accordance with its terms. To be eligible to participate in the DC Plan, an active employee must have had a base salary of at least $150,000, had a hire date on or before December 1, immediately preceding the year in which the employee was able to participate, or be designated as eligible to participate. We matched 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 was at least age 55 may have elected for the matching contributions to be made in any one of the DC Plan’s investment options. The maximum compensation that could have been deferred by employees under all of our deferred compensation plans, including the Chesapeake 401(k) Plan, was a total of 75% of base salary and 75% of performance bonus. The participant chose separate deferral election percentages for both plans. We contributed $7 million, $7 million and $8 million to the DC Plan during 2019, 2018 and 2017, respectively, to fund the match. The deferred compensation company match of 15% had a five-year vesting schedule based on years of service. Any participant who was active on December 31 of the plan year received the deferred compensation company match which was awarded on an annual basis.

14. 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, 2019 and 2018.

Oil, Natural Gas and NGL Derivatives

As of December 31, 2019, and 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. Swaptions allow the counterparty, on a specific date, to extend an existing fixed-price swap for a certain period of time or to increase the notional volumes of an existing fixed-price swap.
- *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, 2019 and 2018 are provided below:

	December 31, 2019		December 31, 2018	
	Notional Volume	Fair Value	Notional Volume	Fair Value
		($ in millions)		($ in millions)
Oil (mmbbl):				
Fixed-price swaps	24	$ (7)	12	$ 157
Collars	2	14	8	98
Basis protection swaps	8	(2)	7	5
Total oil	34	5	27	260
Natural gas (bcf):				
Fixed-price swaps	265	125	623	26
Three-way collars	—	—	88	1
Collars	—	—	55	(3)
Call options	22	—	44	—
Call swaptions	29	(2)	106	(9)
Basis protection swaps	30	2	50	—
Total natural gas	346	125	966	15
Contingent Consideration:				
Utica divestiture		—		7
Total estimated fair value		$ 130		$ 282

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. The contingent consideration expired on December 31, 2019 with no value attributed to the arrangement. See Note 3 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.

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, 2019, and 2018 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, 2019			
Commodity Contracts:			
Short-term derivative asset	$ 174	$ (40)	$ 134
Short-term derivative liability	(42)	40	(2)
Long-term derivative liability	(2)	—	(2)
Total derivatives	$ 130	$ —	$ 130
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, 2019 and 2018, 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, 2019, 2018 and 2017 are presented below:

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
Oil, natural gas and NGL revenues	$ 4,517	$ 5,189	$ 4,574
Gains on undesignated oil, natural gas and NGL derivatives	40	—	445
Losses on terminated cash flow hedges	(35)	(34)	(34)
Total oil, natural gas and NGL revenues	$ 4,522	$ 5,155	$ 4,985

The components of marketing revenues for the years ended December 31, 2019, 2018 and 2017 are presented below:

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
Marketing revenues	$ 3,971	$ 5,069	$ 4,511
Gains (losses) on undesignated marketing natural gas derivatives	(4)	7	—
Total marketing revenues	$ 3,967	$ 5,076	$ 4,511

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,					
	2019		2018		2017	
	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)					
Balance, beginning of period	$ (80)	$ (23)	$ (114)	$ (57)	$ (153)	$ (96)
Net change in fair value	—	—	—	—	5	5
Losses reclassified to income	35	35	34	34	34	34
Balance, end of period	$ (45)	$ 12	$ (80)	$ (23)	$ (114)	$ (57)

The accumulated other comprehensive loss as of December 31, 2019 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 we early adopted ASU 2019-12 in the current period, the tax effect will be recognized in earnings in the year ended December 31, 2022. As of December 31, 2019, we expect to transfer approximately $33 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, 2019, our oil, natural gas and NGL derivative instruments were spread among 10 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, 2019, we did not have any cash or letters of credit 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, 2019 and 2018:

	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, 2019				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 160	$ 14	$ 174
Commodity liabilities	—	(42)	(2)	(44)
Total derivatives	$ —	$ 118	$ 12	$ 130
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

A summary of the changes in the fair values of our financial assets (liabilities) classified as Level 3 during 2019 and 2018 is presented below:

	Commodity Derivatives		Utica Contingent Consideration	
	($ in millions)			
Balance, as of January 1, 2019	$	87	$	7
Total gains (losses) (realized/unrealized):				
Included in earnings[(a)]		(59)		(7)
Total purchases, issuances, sales and settlements:				
Settlements		(16)		—
Balance, as of December 31, 2019	$	12	$	—
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

(a)

	Commodity Derivatives				Utica Contingent Consideration			
	2019		2018		2019		2018	
	($ in millions)							
Total gains (losses) included in earnings for the period	$	(59)	$	77	$	(7)	$	7
Change in unrealized gains (losses) related to assets still held at reporting date	$	(19)	$	86	$	—	$	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, 2019:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value December 31, 2019	
				($ in millions)	
Oil trades	Oil price volatility curves	20.71% – 67.28%	25.62%	$	14
Natural gas trades	Natural gas price volatility curves	16.93% – 171.49%	39.67%	$	(2)

15. 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, 2019 and 2018:

	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, 2019				
Financial Assets (Liabilities):				
Other current assets	$ 42	$ —	$ —	$ 42
Other current liabilities	(43)	—	—	(43)
Total	$ (1)	$ —	$ —	$ (1)
As of December 31, 2018				
Financial Assets (Liabilities):				
Other current assets	$ 50	$ —	$ —	$ 50
Other current liabilities	(51)	—	—	(51)
Total	$ (1)	$ —	$ —	$ (1)

See Note 5 for information regarding fair value measurement of our debt instruments. See Note 14 for information regarding fair value measurement of our derivatives.

16. Capitalized Exploratory Well Costs

A summary of the changes in our capitalized well costs for the years ended December 31, 2019, 2018 and 2017 is detailed below. Additions pending the determination of proved reserves excludes amounts capitalized and subsequently charged to expense within the same year.

	2019	2018	2017
	(in millions)		
Balance as of January 1	$ 36	$ 36	$ 41
Additions pending the determination of proved reserves	7	74	14
Divestitures and other	(3)	—	—
Reclassifications to proved properties	(17)	(40)	(19)
Charges to exploration expense	(16)	(34)	—
Balance as of December 31	$ 7	$ 36	$ 36

The following table provides an aging of capitalized costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling.

	2019	2018	2017
		(in millions)	
Exploratory well costs capitalized for a period of one year or less	$ 7	$ 34	$ 4
Exploratory well costs capitalized for a period greater than one year	—	2	32
Balance as of December 31	$ 7	$ 36	$ 36
Number of projects with exploratory well costs capitalized for a period greater than one year	—	7	6

17. 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, 2019	December 31, 2018	Estimated Useful Life
	($ in millions)		(in years)
Buildings and improvements	$ 1,058	$ 1,053	10 – 39
Computer equipment	355	353	5
Sand mine	78	—	10 – 30
Natural gas compressors[(a)]	48	48	3 – 20
Land	115	106	
Other	156	161	5 – 20
Total other property and equipment, at cost	1,810	1,721	
Less: accumulated depreciation	(692)	(630)	
Total other property and equipment, net	$ 1,118	$ 1,091	

(a) Includes assets under finance lease of $27 million, less accumulated depreciation of $10 million and $1 million, as of December 31, 2019 and 2018, respectively. The related amortization expense for assets under finance lease is included in depreciation, depletion and amortization expense on our consolidated statement of operations.

18. Investments

FTS International, Inc. (NYSE: FTSI). In 2018, FTS International, Inc. 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 2019, the hydraulic fracturing industry experienced challenging operating conditions resulting in the current fair value of our investment in FTSI falling below book value of $65 million and remaining below that amount as of the end of the year. Based on FTSI's 2019 operating results and FTSI's share price of $1.04 per share as of December 31, 2019, we determined that the reduction in fair value is other-than-temporary, and recognized an impairment of our investment in FTSI of approximately $43 million. We will continue to monitor the hydraulic fracturing industry, FTSI operating results and FTSI share price for indicators that the reduction in fair value is other-than-temporary, which could result in an additional impairment of our investment in FTSI.

JWH Midstream LLC (JWH). In 2019, in connection with the acquisition of WildHorse, we obtained a 50% membership interest in JWH Midstream LLC (JWH). The carrying value of our investment in JWH, which was being accounted for as an equity method investment, was approximately $17 million. In 2019, we paid approximately $7 million to terminate our involvement in the partnership. This removed us from any future obligations related to this joint venture and, therefore, we impaired the full value of the investment and recognized approximately $24 million of impairment expense in 2019.

19. Impairments

Impairments of Oil and Natural Gas Properties

A summary of our impairments of oil and natural gas properties for the years ended December 31, 2019, 2018 and 2017 is as follows:

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
Impairments due to lower forecasted commodity prices	$ 8	$ 23	$ 27
Impairments due to reduction in future development[(a)]	—	—	560
Impairments due to anticipated sale	—	55	222
Total impairments of oil and natural gas properties	$ 8	$ 78	$ 809

(a) The impairment was the result of an updated development plan in 2017, which included a removal of PUDs from properties in the process of being divested in the Mid-Continent operating area.

Impairments of Fixed Assets

A summary of our impairments of fixed assets by asset class and other charges for the years ended December 31, 2019, 2018 and 2017 is as follows:

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
Natural gas compressors[(a)]	$ —	$ 45	$ —
Buildings and land	1	4	5
Other	2	4	—
Total impairments of fixed assets and other	$ 3	$ 53	$ 5

(a) 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.

20. Other Operating Expense

In 2019, we recorded approximately $37 million of costs related to our acquisition of WildHorse which consisted of consulting fees, financial advisory fees, legal fees and travel and lodging expenses. In addition, we recorded approximately $38 million of severance expense as a result of the acquisition of WildHorse. A majority of the WildHorse executives and employees were terminated on the date of acquisition. These executives and employees were entitled to severance benefits in accordance with existing employment agreements.

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.

21. Restructuring and Other Termination Costs

Workforce Reductions

In 2019, we incurred a charge of $12 million related to one-time termination benefits for certain employees. 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.

22. Asset Retirement Obligations

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

	Years Ended December 31,	
	2019	2018
	($ in millions)	
Asset retirement obligations, beginning of period	$ 166	$ 177
Additions[a]	21	3
Revisions	18	11
Settlements and disposals	(5)	(35)
Accretion expense	11	10
Asset retirement obligations, end of period	211	166
Less current portion	11	11
Asset retirement obligation, long-term	$ 200	$ 155

(a) During 2019, approximately $17 million of additions relate to the acquisition of WildHorse.

23. Major Customers

Sales to Valero Energy Corporation constituted approximately 12% and 10% of total revenues (before the effects hedging for the years ended December 31, 2019 and 2018, respectively. Sales to Royal Dutch Shell PLC constituted approximately 10% of total revenues (before the effects of hedging) for the year ended December 31, 2017. No other purchasers accounted for more than 10% of our total revenues in 2019, 2018 or 2017.

24. 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, 2019, 2018 and 2017, our expenditures for hydraulic fracturing services with FTSI were nominal, $93 million and $111 million, respectively.

25. 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 the revolving credit facility, term loan, senior secured second lien notes, and outstanding senior unsecured notes and convertible senior notes listed in Note 5 are fully and unconditionally guaranteed, jointly and severally, by certain of our 100% owned subsidiaries. Our BVL subsidiaries are guarantors of our obligations under the revolving credit facility, term loan and senior secured second lien notes, but are not guarantors of our obligations under our outstanding senior unsecured notes or convertible senior notes as of December 31, 2019. Chesapeake has an obligation and intends to add our BVL subsidiaries as guarantors of our obligations under such notes on or before June 20, 2020 in accordance with the various indentures governing the same. 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, including BVL subsidiaries, as of December 31, 2019 and 2018 and for the years ended December 31, 2019, 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, 2019
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 16	$ 1	$ 5	$ (16)	$ 6
Other current assets	51	1,090	104	—	1,245
Intercompany receivable, net	7,702	—	—	(7,702)	—
Total Current Assets	7,769	1,091	109	(7,718)	1,251
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties at cost, based on successful efforts accounting, net	—	9,440	4,188	—	13,628
Other property and equipment, net	—	1,030	88	—	1,118
Property and equipment held for sale, net	—	10	—	—	10
Total Property and Equipment, Net	—	10,480	4,276	—	14,756
LONG-TERM ASSETS:					
Other long-term assets	41	125	19	1	186
Investments in subsidiaries and intercompany advances	6,101	4,171	—	(10,272)	—
TOTAL ASSETS	$ 13,911	$ 15,867	$ 4,404	$ (17,989)	$ 16,193
CURRENT LIABILITIES:					
Current liabilities	$ 466	$ 1,765	$ 176	$ (15)	$ 2,392
Intercompany payable, net	—	7,702	—	(7,702)	—
Total Current Liabilities	466	9,467	176	(7,717)	2,392
LONG-TERM LIABILITIES:					
Long-term debt, net	9,071	—	2	—	9,073
Deferred income tax liabilities	10	—	—	—	10
Other long-term liabilities	—	299	18	—	317
Total Long-Term Liabilities	9,081	299	20	—	9,400
EQUITY:					
Chesapeake stockholders' equity	4,364	6,101	4,171	(10,272)	4,364
Noncontrolling interests	—	—	37	—	37
Total Equity	4,364	6,101	4,208	(10,272)	4,401
TOTAL LIABILITIES AND EQUITY	$ 13,911	$ 15,867	$ 4,404	$ (17,989)	$ 16,193

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	6,671	—	—	(6,671)	—
Total Current Assets	6,735	1,533	3	(6,673)	1,598
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties at cost, based on successful efforts accounting, net	—	9,664	48	—	9,712
Other property and equipment, net	—	1,091	—	—	1,091
Property and equipment held for sale, net	—	15	—	—	15
Total Property and Equipment, Net	—	10,770	48	—	10,818
LONG-TERM ASSETS:					
Other long-term assets	26	293	—	—	319
Investments in subsidiaries and intercompany advances	3,248	9	—	(3,257)	—
TOTAL ASSETS	$ 10,009	$ 12,605	$ 51	$ (9,930)	$ 12,735
CURRENT LIABILITIES:					
Current liabilities	$ 523	$ 2,365	$ 1	$ (2)	$ 2,887
Intercompany payable, net	—	6,671	—	(6,671)	—
Total Current Liabilities	523	9,036	1	(6,673)	2,887
LONG-TERM LIABILITIES:					
Long-term debt, net	7,341	—	—	—	7,341
Other long-term liabilities	53	321	—	—	374
Total Long-Term Liabilities	7,394	321	—	—	7,715
EQUITY:					
Chesapeake stockholders’ equity	2,092	3,248	9	(3,257)	2,092
Noncontrolling interests	—	—	41	—	41
Total Equity	2,092	3,248	50	(3,257)	2,133
TOTAL LIABILITIES AND EQUITY	$ 10,009	$ 12,605	$ 51	$ (9,930)	$ 12,735

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2019
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES AND OTHER:					
Oil, natural gas and NGL	$ —	$ 3,760	$ 762	$ —	$ 4,522
Marketing	—	3,967	—	—	3,967
Total Revenues	—	7,727	762	—	8,489
Other	—	60	3	—	63
Gains on sales of assets	—	43	—	—	43
Total Revenues and Other	—	7,830	765	—	8,595
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	436	84	—	520
Oil, natural gas and NGL gathering, processing and transportation	—	1,062	20	—	1,082
Severance and ad valorem taxes	—	174	50	—	224
Exploration	—	77	7	—	84
Marketing	—	4,003	—	—	4,003
General and administrative	1	237	77	—	315
Restructuring and other termination costs	—	12	—	—	12
Provision for legal contingencies, net	—	19	—	—	19
Depreciation, depletion and amortization	—	1,719	545	—	2,264
Impairments	—	11	—	—	11
Other operating expense	—	52	40	—	92
Total Operating Expenses	1	7,802	823	—	8,626
INCOME (LOSS) FROM OPERATIONS	(1)	28	(58)	—	(31)
OTHER INCOME (EXPENSE):					
Interest income (expense)	(598)	16	(69)	—	(651)
Losses on investments	—	(47)	(24)	—	(71)
Gains on purchases or exchanges of debt	65	—	10	—	75
Other income	—	39	—	—	39
Equity in net earnings (losses) of subsidiary	(105)	(141)	—	246	—
Total Other Expense	(638)	(133)	(83)	246	(608)
LOSS BEFORE INCOME TAXES	(639)	(105)	(141)	246	(639)
INCOME TAX BENEFIT	(331)	—	—	—	(331)
NET LOSS	(308)	(105)	(141)	246	(308)
Net income attributable to noncontrolling interests	—	—	—	—	—
NET LOSS ATTRIBUTABLE TO CHESAPEAKE	(308)	(105)	(141)	246	(308)
Other comprehensive income	—	35	—	—	35
COMPREHENSIVE LOSS ATTRIBUTABLE TO CHESAPEAKE	$ (308)	$ (70)	$ (141)	$ 246	$ (273)

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES AND OTHER:					
Oil, natural gas and NGL	$ —	$ 5,136	$ 19	$ —	$ 5,155
Marketing	—	5,076	—	—	5,076
Total Revenues	—	10,212	19	—	10,231
Other	—	63	—	—	63
Losses on sales of assets	—	(264)	—	—	(264)
Total Revenues and Other	—	10,011	19	—	10,030
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	474	—	—	474
Oil, natural gas and NGL gathering, processing and transportation	—	1,391	7	—	1,398
Severance and ad valorem taxes	—	188	1	—	189
Exploration	—	162	—	—	162
Marketing	—	5,158	—	—	5,158
General and administrative	2	332	1	—	335
Restructuring and other termination costs	—	38	—	—	38
Provision for legal contingencies, net	—	26	—	—	26
Depreciation, depletion and amortization	—	1,730	7	—	1,737
Impairments	—	131	—	—	131
Total Operating Expenses	2	9,630	16	—	9,648
INCOME (LOSS) FROM OPERATIONS	(2)	381	3	—	382
OTHER INCOME (EXPENSE):					
Interest expense	(631)	(2)	—	—	(633)
Gains on investments	—	139	—	—	139
Gains on purchases or exchanges of debt	263	—	—	—	263
Other income	3	64	—	—	67
Equity in net earnings of subsidiary	583	1	—	(584)	—
Total Other Income (Expense)	218	202	—	(584)	(164)
INCOME BEFORE INCOME TAXES	216	583	3	(584)	218
INCOME TAX BENEFIT	(10)	—	—	—	(10)
NET INCOME	226	583	3	(584)	228
Net income attributable to noncontrolling interests	—	—	(2)	—	(2)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	226	583	1	(584)	226
Other comprehensive income	—	34	—	—	34
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$ 226	$ 617	$ 1	$ (584)	$ 260

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES AND OTHER:					
Oil, natural gas and NGL	$ —	$ 4,962	$ 23	$ —	$ 4,985
Marketing	—	4,511	—	—	4,511
Total Revenues	—	9,473	23	—	9,496
Other	—	67	—	—	67
Gains on sales of assets	—	476	—	—	476
Total Revenues and Other	—	10,016	23	—	10,039
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	517	—	—	517
Oil, natural gas and NGL gathering, processing and transportation	—	1,463	8	—	1,471
Severance and ad valorem taxes	—	133	1	—	134
Exploration	—	235	—	—	235
Marketing	—	4,598	—	—	4,598
General and administrative	1	330	2	—	333
Provision for legal contingencies, net	(79)	41	—	—	(38)
Depreciation, depletion and amortization	—	1,688	9	—	1,697
Impairments	—	814	—	—	814
Other operating expense	—	416	—	—	416
Total Operating (Income) Expenses	(78)	10,235	20	—	10,177
INCOME (LOSS) FROM OPERATIONS	78	(219)	3	—	(138)
OTHER INCOME (EXPENSE):					
Interest expense	(599)	(2)	—	—	(601)
Gains on purchases or exchanges of debt	233	—	—	—	233
Other income	1	5	—	—	6
Equity in net losses of subsidiary	(216)	—	—	216	—
Total Other Income (Expense)	(581)	3	—	216	(362)
INCOME (LOSS) BEFORE INCOME TAXES	(503)	(216)	3	216	(500)
INCOME TAX EXPENSE	2	—	—	—	2
NET INCOME (LOSS)	(505)	(216)	3	216	(502)
Net income attributable to noncontrolling interests	—	—	(3)	—	(3)
NET LOSS ATTRIBUTABLE TO CHESAPEAKE	(505)	(216)	—	216	(505)
Other comprehensive income	—	39	—	—	39
COMPREHENSIVE LOSS ATTRIBUTABLE TO CHESAPEAKE	$ (505)	$ (177)	$ —	$ 216	$ (466)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2019
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$ 1	$ 1,270	$ 356	$ (4)	$ 1,623
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(1,548)	(632)	—	(2,180)
Business combination, net	—	(381)	28	—	(353)
Acquisitions of proved and unproved properties	—	(35)	—	—	(35)
Proceeds from divestitures of proved and unproved properties	—	130	—	—	130
Additions to other property and equipment	—	(32)	(16)	—	(48)
Proceeds from sales of other property and equipment	—	6	—	—	6
Net Cash Used In Investing Activities	—	(1,860)	(620)	—	(2,480)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving credit facility borrowings	9,839	—	837	—	10,676
Payments on revolving credit facility borrowings	(8,668)	—	(1,512)	—	(10,180)
Proceeds from issuance of senior notes, net	108	—	—	—	108
Proceeds from issuance of term loan, net	1,455	—	—	—	1,455
Cash paid to purchase debt	(380)	—	(693)	—	(1,073)
Cash paid for preferred stock dividends	(91)	—	—	—	(91)
Contribution from parent	(1,644)	—	1,644	—	—
Other financing activities	(24)	(8)	(8)	4	(36)
Intercompany advances, net	(713)	713	—	—	—
Net Cash Provided By (Used In) Financing Activities	(118)	705	268	4	859
Net increase (decrease) in cash and cash equivalents	(117)	115	4	—	2
Cash and cash equivalents, beginning of period	4	1	1	(2)	4
Cash and cash equivalents, end of period	$ (113)	$ 116	$ 5	$ (2)	$ 6

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	$ 1,642	$ 10	$ (7)	$ 1,730
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(1,848)	—	—	(1,848)
Acquisitions of proved and unproved properties	—	(128)	—	—	(128)
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	—	455	—	—	455
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	$ 466	$ 14	$ (10)	$ 475
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(2,113)	—	—	(2,113)
Acquisitions of proved and unproved properties	—	(88)	—	—	(88)
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	—	(918)	—	—	(918)
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

26. Subsequent Events

On February 24, 2020, we executed agreements to terminate certain gathering, processing and transportation contracts in exchange for consideration of approximately $70 million, comprised of $54 million in cash and $16 million of linefill inventory. During the first quarter of 2020, we will recognize a non-recurring $70 million expense related to the contract termination. Additionally, the contract termination will remove approximately $169 million of future commitments related to gathering, processing and transportation agreements. See Note 6 for further discussion of contingencies and commitments.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
SUPPLEMENTARY INFORMATION

Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2019 and 2018 are as follows:

	2019 First Quarter	2019 Second Quarter	2019 Third Quarter	2019 Fourth Quarter
	($ in millions except per share data)			
Total revenues	$ 2,196	$ 2,386	$ 2,087	$ 1,926
Income (loss) from operations	$ (182)	$ 278	$ 46	$ (173)
Net income (loss) attributable to Chesapeake	$ (21)	$ 98	$ (61)	$ (324)
Net income (loss) available to common stockholders	$ (44)	$ 75	$ (101)	$ (346)
Net income (loss) per common share:				
Basic	$ (0.03)	$ 0.05	$ (0.06)	$ (0.18)
Diluted	$ (0.03)	$ 0.05	$ (0.06)	$ (0.18)

	2018 First Quarter	2018 Second Quarter	2018 Third Quarter	2018 Fourth Quarter
	($ in millions except per share data)			
Total revenues	$ 2,524	$ 2,289	$ 2,424	$ 2,793
Income (loss) from operations	$ 42	$ (160)	$ 82	$ 418
Net income (loss) attributable to Chesapeake	$ 17	$ (249)	$ (146)	$ 604
Net income (loss) available to common stockholders	$ (6)	$ (272)	$ (169)	$ 576
Net income (loss) per common share:				
Basic	$ (0.01)	$ (0.30)	$ (0.19)	$ 0.63
Diluted	$ (0.01)	$ (0.30)	$ (0.19)	$ 0.57

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, 2019	December 31, 2018
	($ in millions)	
Oil and oil and natural gas properties:		
Proved	$ 30,765	$ 25,407
Unproved	2,173	1,561
Total	32,938	26,968
Less accumulated depreciation, depletion and amortization	(19,310)	(17,256)
Net capitalized costs	$ 13,628	$ 9,712

Unproved properties as of December 31, 2019 and 2018, consisted mainly of leasehold acquired through direct purchases of significant oil and natural gas property interests. 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, including capitalized interest and asset retirement costs, are summarized as follows:

	Years Ended December 31, 2019	2018	2017
	($ in millions)		
Acquisition of Properties[(a)]:			
Proved properties	$ 3,264	$ 80	$ 23
Unproved properties	792	56	74
Exploratory costs	42	80	22
Development costs	2,177	1,954	2,075
Costs incurred	$ 6,275	$ 2,170	$ 2,194

(a) Includes $3.264 billion and $756 million of proved and unproved property acquisitions, respectively, related to our acquisition of WildHorse in 2019.

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 2019, 2018 and 2017. 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,		
	2019	2018	2017
	($ in millions)		
Oil, natural gas and NGL sales	$ 4,522	$ 5,155	$ 4,985
Other revenue	63	63	67
Oil, natural gas and NGL production expenses	(520)	(474)	(517)
Oil, natural gas and NGL gathering, processing and transportation expenses	(1,082)	(1,398)	(1,471)
Severance and ad valorem taxes	(224)	(189)	(134)
Exploration	(84)	(162)	(235)
Depletion and depreciation	(2,188)	(1,665)	(1,615)
Impairment of oil and natural gas properties	(8)	(78)	(809)
Imputed income tax provision[(a)]	(125)	(326)	(107)
Results of operations from oil, natural gas and NGL producing activities	$ 354	$ 926	$ 164

(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, 2019, 2018 and 2017. Our independent petroleum engineering firm, Software Integrated Solutions, Division of Schlumberger Technology Corporation, estimated an aggregate of 81%, 80% and 83% of our estimated proved reserves (by volume) as of December 31, 2019, 2018 and 2017.

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 2019, 2018 and 2017:

	Oil	Natural Gas	NGL	Total
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)
December 31, 2019				
Proved reserves, beginning of period	215.5	6,777	103.3	1,448
Extensions, discoveries and other additions	52.2	897	13.9	216
Revisions of previous estimates	(40.9)	(516)	(15.8)	(143)
Production	(43.0)	(728)	(12.3)	(177)
Sale of reserves-in-place	(1.8)	(23)	(1.4)	(7)
Purchase of reserves-in-place	176.0	159	32.3	235
Proved reserves, end of period	358.0	6,566	120.0	1,572
Proved developed reserves:				
Beginning of period	127.6	3,314	67.9	748
End of period	201.4	3,377	82.1	846
Proved undeveloped reserves:				
Beginning of period	87.9	3,463	35.4	700
End of period[(a)]	156.6	3,189	37.9	726

	Oil (mmbbl)	Natural Gas (bcf)	NGL (mmbbl)	Total (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	215.5	6,777	103.3	1,448
Proved developed reserves:				
Beginning of period	150.9	4,980	135.0	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[(a)]	87.9	3,463	35.4	700
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	260.2	8,600	218.6	1,912
Proved developed reserves:				
Beginning of period	200.4	5,126	134.2	1,189
End of period	150.9	4,980	135.0	1,116
Proved undeveloped reserves:				
Beginning of period	198.7	1,370	92.2	519
End of period[(a)]	109.3	3,620	83.6	796

(a) As of December 31, 2019, 2018 and 2017, there were no PUDs that had remained undeveloped for five years or more.

During 2019, we acquired 235 mmboe primarily related to the acquisition of WildHorse. We recorded extensions and discoveries of 216 mmboe, primarily related to undeveloped well additions in the Marcellus and Brazos Valley operating areas. In addition, we recorded downward revisions of 110 mmboe due to lower oil, natural gas and NGL prices in 2019, and downward revisions of 33 mmboe due to ongoing portfolio evaluation including lateral length adjustments, performance and updates to our five-year development plan. The oil and natural gas prices used in computing our reserves as of December 31, 2019, were $55.69 per bbl and $2.58 per mcf, respectively, before price differentials.

During 2018, we sold 559 mmboe of proved reserves for approximately $1.8 billion primarily in the Utica and Mid-Continent. 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.

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, 2019, 2018 and 2017 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,		
	2019	2018	2017
	($ in millions)		
Future cash inflows	$ 29,857 [(a)]	$ 27,312 [(b)]	$ 26,412 [(c)]
Future production costs	(6,956)	(5,946)	(7,044)
Future development costs	(5,757)	(4,032)	(4,977)
Future income tax provisions	(75)	(331)	—
Future net cash flows	17,069	17,003	14,391
Less effect of a 10% discount factor	(8,069)	(7,508)	(6,901)
Standardized measure of discounted future net cash flows[(d)]	$ 9,000	$ 9,495	$ 7,490

(a) Calculated using prices of $55.69 per bbl of oil and $2.58 per mcf of natural gas, before field differentials.

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

(c) Calculated using prices of $51.34 per bbl of oil and $2.98 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 7.

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

	Years Ended December 31,		
	2019	2018	2017
	($ in millions)		
Standardized measure, beginning of period[(a)]	$ 9,495	$ 7,490	$ 4,379
Sales of oil and natural gas produced, net of production costs and gathering, processing and transportation[(b)]	(2,691)	(3,128)	(2,452)
Net changes in prices and production costs	(3,457)	3,317	3,977
Extensions and discoveries, net of production and development costs	991	1,666	1,951
Changes in estimated future development costs	366	1,113	614
Previously estimated development costs incurred during the period	775	973	775
Revisions of previous quantity estimates	(793)	47	(1,255)
Purchase of reserves-in-place	3,435	—	3
Sales of reserves-in-place	(57)	(2,052)	(116)
Accretion of discount	953	749	441
Net change in income taxes	17	(32)	26
Changes in production rates and other	(34)	(648)	(853)
Standardized measure, end of period[(a)]	$ 9,000	$ 9,495	$ 7,490

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

(b) Excludes gains and losses on derivatives.

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, 2019 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, 2019 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, 2020 (the 2020 Proxy Statement).

ITEM 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the 2020 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 2020 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 2020 Proxy Statement.

ITEM 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the 2020 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.	10-K	001-13726	3.1.1	2/27/2019	
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	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	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
4.4.2	First Amendment to Amended and Restated Credit Agreement, dated as of February 1, 2019 among Chesapeake Energy Corporation, MUFG Union Bank, N.A. and the Lenders party thereto.	8-K	001-13726	10.1	2/1/2019
4.4.3	Second Amendment to Amended and Restated Credit Agreement, dated as of December 3, 2019 among Chesapeake, MUFG Union Bank, N.A. and the Lenders party thereto.	8-K	001-13726	10.1	12/4/2019

4.4.4	Third Amendment to Amended and Restated Credit Agreement, dated as of December 26, 2019, among Chesapeake, MUFG Union Bank, N.A. and the Lenders party thereto.	8-K	001-13726	10.1	12/27/2019
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	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
4.10	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
4.11	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
4.12	Tenth Supplemental Indenture, dated as of April 3, 2019 to Indenture dated as of April 24, 2014 with respect to 8.00% Senior Notes due 2026.	8-K	001-13726	4.2	4/5/2019
4.13	Registration Rights Agreement, dated as of April 3, 2019, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and the dealer managers party thereto, with respect to 8.00% Senior Notes due 2026.	8-K	001-13726	4.4	4/5/2019
4.14.1	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
4.14.2	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

4.14.3	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	
4.14.4	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	
4.14.5	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	
4.14.6	Fifth Supplemental Indenture, dated as of December 19, 2019, to Indenture dated as of February 1, 2017, among Brazos Valley Longhorn, L.L.C., Brazos Valley Longhorn Finance Corp., the guarantors named therein, and U.S. Bank National Association, as trustee.	8-K	001-13726	4.5	12/26/2019	
4.15.1	Indenture, dated as of December 19, 2019, among Chesapeake Energy Corporation, the guarantors named therein, and Deutsche Bank Trust Company Americas, as trustee and as collateral trustee, with respect to 11.5% Senior Notes due 2025.	8-K	001-13726	4.1	12/26/2019	
4.15.2	First Supplemental Indenture, dated as of December 23, 2019, to Indenture dated as of December 19, 2019, among Chesapeake Energy Corporation, the guarantors named therein, and Deutsche Bank Trust Company Americas, as trustee and as collateral trustee, with respect to 11.5% Senior Notes due 2025.	8-K	001-13726	4.2	12/26/2019	
4.16	Term Loan Agreement, dated as of December 19, 2019, among Chesapeake Energy Corporation, the lenders party thereto, and GLAS USA LLC, as term agent.	8-K	001-13726	4.3	12/26/2019	
4.17	Class A Term Loan Supplement, dated as of December 19, 2019, among Chesapeake Energy Corporation, the lenders party thereto, and GLAS USA LLC, as term agent.	8-K	001-13726	4.4	12/26/2019	
4.18	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934.					X
10.1.1†	Chesapeake's 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1	6/20/2013	
10.1.2†	Form of Nonqualified Stock Option Agreement for 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1	2/4/2013	
10.2.1†	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan, effective January 1, 2016.	10-K	001-13726	10.3	2/25/2016	

10.2.2†	Amendment to the Chesapeake Energy Corporation Deferred Compensation Plan, effective January 1, 2019.	10-K	001-13726	10.3.2	2/27/2019
10.3.1†	Chesapeake Energy Corporation Deferred Compensation Plan for Non-Employee Directors.	10-K	001-13726	10.16	3/1/2013
10.3.2†	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
10.4.1†	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
10.4.2†	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
10.4.3†	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
10.4.4†	Pension Makeup Restricted Stock Award Agreement for Robert D. Lawler, dated June 17, 2018.	10-Q	001-13726	10.1	8/1/2018
10.5†	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
10.6†	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
10.7†	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
10.8†	Employment Agreement dated as of January 1, 2019 between Chesapeake Energy Corporation and William M. Buergler.	10-K	001-13726	10.10	2/27/2019
10.9†	Form of Employment Agreement dated as of January 1, 2019 between Executive Vice President/Senior Vice President and Chesapeake Energy Corporation.	10-K	001-13726	10.11	2/27/2019
10.10†	Form of Indemnity Agreement for officers and directors of Chesapeake Energy Corporation and its subsidiaries.	8-K	001-13726	10.3	6/27/2012
10.11†	Chesapeake Energy Corporation 2013 Annual Incentive Plan.	DEF 14A	001-13726	Exhibit G	5/3/2013
10.12.1†	Chesapeake Energy Corporation Restated 2014 Long Term Incentive Plan.	10-Q	001-13726	10.1	8/3/2017
10.12.2†	Form of Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.2	8/6/2014
10.12.3†	Form of Restricted Stock Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.3	8/6/2014

10.12.4†	Form of Nonqualified Stock Option Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.4	8/6/2014	
10.12.5†	Form of Performance Share Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.10	5/9/2019	
10.12.6†	Form of Non-Employee Director Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.6	8/6/2014	
10.13	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	
10.14	Intercreditor Agreement, dated as of December 19, 2019, by and among MUFG Union Bank, N.A., as priority lien agent, and Deutsche Bank Trust Company Americas, as second lien collateral trustee, and acknowledged and agreed to by Chesapeake Energy Corporation and certain of its subsidiaries.	8-K	001-13726	10.1	12/26/2019	
10.15	Collateral Trust Agreement, dated as of December 19, 2019, by and among Chesapeake Energy Corporation, 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	12/26/2019	
10.16	Collateral Trust Agreement, dated as of December 19, 2019, by and among MUFG Union Bank, N.A., as collateral trustee and revolver agent, and GLAS USA LLC, as term loan agent, and acknowledged and agreed by Chesapeake Energy Corporation and certain of its subsidiaries.	8-K	001-13726	10.3	12/26/2019	
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
95.1	Mine Safety Disclosures					X

99.1	Report of Software Integrated Solutions, Division of Schlumberger Technology Corporation.	X
101 INS	Inline XBRL Instance Document.	X
101 SCH	Inline XBRL Taxonomy Extension Schema Document.	X
101 CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.	X
101 DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.	X
101 LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document.	X
101 PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.	X
104	Cover Page Interactive Data file - the Cover Page Interactive Data File does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document	

* 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, 2020

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, 2020
/s/ DOMENIC J. DELL'OSSO, JR. **Domenic J. Dell'Osso, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2020
/s/ WILLIAM M. BUERGLER **William M. Buergler**	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2020
/s/ R. BRAD MARTIN **R. Brad Martin**	Chairman of the Board	February 27, 2020
/s/ GLORIA R. BOYLAND **Gloria R. Boyland**	Director	February 27, 2020
/s/ LUKE R. CORBETT **Luke R. Corbett**	Director	February 27, 2020
/s/ MARK A. EDMUNDS **Mark A. Edmunds**	Director	February 27, 2020
/s/ LESLIE S. KEATING **Leslie S. Keating**	Director	February 27, 2020
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	February 27, 2020
/s/ THOMAS L. RYAN **Thomas L. Ryan**	Director	February 27, 2020

Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934

As of December 31, 2019, Chesapeake Energy Corporation, an Oklahoma corporation ("Chesapeake" or the "Company"), had eight classes of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"): (1) common stock, par value $0.01 per share ("common stock"); (2) 4.5% Cumulative Convertible Preferred Stock, par value $0.01 per share ("4.5% preferred stock"); (3) 6.625% Senior Notes due 2020; (4) 6.875% Senior Notes due 2020; (5) 6.125% Senior Notes due 2021; (6) 5.375% Senior Notes due 2021; (7) 4.875% Senior Notes due 2026; and (8) 5.75% Senior Notes due 2023. Each of Chesapeake's securities registered under Section 12 of the Exchange Act are listed on the New York Stock Exchange. References to "we," "our" and "us" refer to Chesapeake, unless the context otherwise requires.

DESCRIPTION OF CAPITAL STOCK

The following description is a summary only and does not purport to be complete. We encourage you to read the complete text of Chesapeake's amended and restated certificate of incorporation (the "certificate of incorporation"), amended and restated bylaws (the "bylaws") and certificate of designation relating to our 4.5% preferred stock, which we have filed or incorporated by reference as exhibits to Chesapeake's Annual Report on Form 10-K.

General

Pursuant to the certificate of incorporation, we have the authority to issue 3,020,000,000 shares consisting of 20,000,000 shares of preferred stock and 3,000,000,000 shares of common stock. The outstanding shares of our capital stock are fully paid and nonassessable.

Common Stock

Our common stock is listed on the New York Stock Exchange under the symbol "CHK." Holders of our common stock are entitled to one vote for each share held of record on all matters submitted to a vote of shareholders. Subject to preferences and other dividend rights that may be applicable to any outstanding preferred stock, holders of our common stock are entitled to receive such dividends as may be declared on the common stock by the board of directors at any time or from time to time out of funds legally available for dividends. In the event of our liquidation, distribution or winding up, holders of our common stock are entitled to share ratably in all assets remaining after distribution in full of the preferential and other amounts to be distributed.

Holders of our common stock have no preemptive rights.

Preferred Stock

Our board of directors has the authority, without shareholder approval, to issue shares of preferred stock from time to time in one or more series, with such voting rights or without voting rights, and with such designations, powers, preferences and rights and qualifications, limitations or restrictions, as shall be set forth in the resolutions providing therefor. As of December 31, 2019, our authorized preferred stock consisted of:

- 14,436,542 shares that were unissued and undesignated as to series; and
- 5,563,458 shares that were issued and designated as 4.5% preferred stock, 5.00% Cumulative Convertible Preferred Stock (Series 2005B), 5.75% Cumulative Convertible Non-Voting Preferred Stock (Series A) and 5.75% Cumulative Non-Voting Convertible Preferred Stock.

Holders of our existing preferred stock are entitled to elect two additional directors to our board of directors at our next regular or special meeting of shareholders if dividends on such preferred stock are in arrears and unpaid for six or more quarterly periods (whether or not consecutive). Upon the election of any additional directors, the number of directors that comprise our board shall be increased by such number of additional directors. Such voting rights and the terms of the directors so elected will continue until such time as the dividend arrearage on the preferred stock has been paid in full.

While providing desirable flexibility for possible acquisitions and other corporate purposes, and eliminating delays associated with a shareholder vote on specific issuances, the issuance of preferred stock could adversely affect the voting power of holders of common stock, as well as dividend and liquidation payments on both common and preferred stock. It also could have the effect of delaying, deferring or preventing a change in control.

Dividends

Holders of shares of 4.5% preferred stock will be entitled to receive, when, as and if declared by our board of directors out of funds legally available for payment, cumulative dividends at the rate per annum of 4.50% per share on the liquidation preference thereof of $100 per share of 4.5% preferred stock (equivalent to $4.50 per annum per share). Dividends on the 4.5% preferred stock will be payable quarterly on March 15, June 15, September 15 and December 15 of each year, commencing December 15, 2005 (each, a "Dividend Payment Date") at such annual rate, and shall accumulate from the most recent date as to which dividends shall have been paid or, if no dividends have been paid, from the issue date of the 4.5% preferred stock, whether or not in any dividend period or periods there have been funds legally available for the payment of such dividends. Dividends will be payable to holders of record as they appear on our stock register on the immediately preceding March 1, June 1, September 1 and December 1 (each, a "Record Date"). Accumulations of dividends on shares of 4.5% preferred stock do not bear interest. Dividends payable on the 4.5% preferred stock for any period other than a full dividend period (based upon the number of days elapsed during the period) are computed on the basis of a 360-day year consisting of twelve 30-day months.

No dividend will be declared or paid upon, or any sum set apart for the payment of dividends upon, any outstanding share of the 4.5% preferred stock with respect to any dividend period unless all dividends for all preceding dividend periods have been declared and paid or declared and a sufficient sum or number of shares of common stock have been set apart for the payment of such dividend, upon all outstanding shares of 4.5% preferred stock.

No dividend on the 4.5% preferred stock will be paid in cash at any time that the Adjusted Consolidated EBITDA Coverage Ratio (as defined in the indenture among the Company, the Subsidiary Guarantors (as defined therein) and The Bank of New York Trust Company, N.A. dated as of June 30, 2005) is less than 2.00 to 1.00.

No dividends or other distributions (other than a dividend or distribution payable solely in shares of Parity Stock or Junior Stock (in the case of Parity Stock) or Junior Stock (in the case of Junior Stock) and cash in lieu of fractional shares) may be declared, made or paid, or set apart for payment upon, any Parity Stock or Junior Stock, nor may any Parity Stock or Junior Stock be redeemed, purchased or otherwise acquired for any consideration (or any money paid to or made available for a sinking fund for the redemption of any Parity Stock or Junior Stock) by us or on our behalf (except by conversion into or exchange for shares of Parity Stock or Junior Stock (in the case of Parity Stock) or Junior Stock (in the case of Junior Stock)) unless all accumulated and unpaid dividends have been or contemporaneously are declared and paid, or are declared and a sum or number of shares of common stock sufficient for the payment thereof is set apart for such payment, on the 4.5% preferred stock and any Parity Stock for all dividend payment periods terminating on or prior to the date of such declaration, payment, redemption, purchase or acquisition. Notwithstanding the preceding, if full dividends have not been paid on the 4.5% preferred stock and any Parity Stock, dividends may be declared and paid on the 4.5% preferred stock and such Parity Stock so long as the dividends are declared and paid pro rata so that the amounts of dividends declared per share on the 4.5% preferred stock and such Parity Stock will in all cases bear to each other the same ratio that accumulated and unpaid dividends per share on the shares of the 4.5% preferred stock and such Parity Stock bear to each other. Holders of shares of the 4.5% preferred stock will not be entitled to any dividend, whether payable in cash, property or stock, in excess of full cumulative dividends.

Our ability to declare and pay cash dividends and make other distributions with respect to our capital stock, including the 4.5% preferred stock, is limited by the terms of the Company's outstanding indebtedness. In addition, our ability to declare and pay dividends may be limited by applicable Oklahoma law.

Method of Payment of Dividends

Subject to certain restrictions, we may generally pay any dividend on the 4.5% preferred stock:

- in cash;
- by delivery of shares of our Common stock; or
- through any combination of cash and our Common stock.

If we elect to make any such payment, or any portion thereof, in shares of our common stock, such shares shall be valued for such purpose, in the case of any dividend payment, or portion thereof, at 97% of the Market Value (as defined below under "—Conversion Price Adjustment") as determined on the second Trading Day immediately prior to the Record Date for such dividend.

We will make each dividend payment on the 4.5% preferred stock in cash, except to the extent we elect to make all or any portion of such payment in shares of our common stock. We will give the holders of the 4.5% preferred stock notice of any such election and the portion of such payment that will be made in cash and the portion that will be made in common stock 10 Trading Days prior to the Record Date for such dividend.

No fractional shares of common stock will be delivered to the holders of the 4.5% preferred stock, but we will instead pay a cash adjustment to each holder that would otherwise be entitled to a fraction of a share of common stock. Any portion of any such payment that is declared and not paid through the delivery of shares of common stock will be paid in cash.

Notwithstanding the above, we may not pay any portion of a dividend on the 4.5% preferred stock by delivery of common stock unless (i) the common stock to be delivered as payment therefore is freely transferable by the recipient without further action on its behalf, other than by reason of the fact that such recipient is our affiliate, or (ii) a shelf registration statement relating to that common stock has been filed with the SEC and is effective to permit the resale of that common stock by the holders thereof.

Liquidation Preference

In the event of our voluntary or involuntary liquidation, winding-up or dissolution, each holder of 4.5% preferred stock will be entitled to receive and to be paid out of our assets available for distribution to our stockholders, before any payment or distribution is made to holders of Junior Stock (including common stock), a liquidation preference in the amount of $100 per share of the 4.5% preferred stock, plus accumulated and unpaid dividends on the shares to the date fixed for liquidation, winding-up or dissolution. If, upon our voluntary or involuntary liquidation, winding-up or dissolution, the amounts payable with respect to the liquidation preference of the 4.5% preferred stock and all Parity Stock are not paid in full, the holders of the 4.5% preferred stock and the Parity Stock will share equally and ratably in any distribution of our assets in proportion to the full liquidation preference and accumulated and unpaid dividends to which they are entitled. After payment of the full amount of the liquidation preference and accumulated and unpaid dividends to which they are entitled, the holders of the 4.5% preferred stock will have no right or claim to any of our remaining assets. Neither the sale of all or substantially all our assets or business (other than in connection with our liquidation, winding-up or dissolution), nor our merger or consolidation into or with any other person, will be deemed to be our voluntary or involuntary liquidation, winding-up or dissolution.

The certificate of designation will not contain any provision requiring funds to be set aside to protect the liquidation preference of the 4.5% preferred stock even though it is substantially in excess of the par value thereof.

Voting Rights

The holders of the 4.5% preferred stock will have no voting rights except as set forth below or as otherwise required by Oklahoma law from time to time.

If dividends on the 4.5% preferred stock are in arrears and unpaid for six or more quarterly periods (whether or not consecutive), the holders of the 4.5% preferred stock, voting as a single class with any other preferred stock or preference securities having similar voting rights that are exercisable, will be entitled at our next regular or special meeting of stockholders to elect two additional directors to our board of directors. Upon the election of any additional directors, the number of directors that comprise our board shall be increased by such number of additional directors. Such voting rights and the terms of the directors so elected will continue until such time as the dividend arrearage on the 4.5% preferred stock has been paid in full.

In addition, the affirmative vote or consent of the holders of at least 66 2/3% of the outstanding 4.5% preferred stock will be required for the authorization or issuance of any class or series of Senior Stock (or any security convertible into Senior Stock) and for amendments to our certificate of incorporation that would affect adversely the rights of holders of the 4.5% preferred stock. The certificate of designation will provide that the authorization of, the increase in the authorized amount of, or the issuance of any shares of any class or series of Parity Stock or Junior Stock will not require the consent of the holders of the 4.5% preferred stock, and will not be deemed to affect adversely the rights of the holders of the 4.5% preferred stock.

In all cases in which the holders of 4.5% preferred stock shall be entitled to vote, each share of 4.5% preferred stock shall be entitled to one vote.

Conversion Rights

Each share of 4.5% preferred stock will be convertible at any time at the option of the holder thereof into such whole number of fully paid and nonassessable shares of common stock as is equal, subject to certain limitations, to the product of the number of shares of preferred stock being so converted multiplied by the quotient of (i) $100.00 per share of 4.5% preferred stock divided by (ii) the conversion price then in effect (and we refer to such price or adjusted price as the “Conversion Price”). Please see “—Conversion Price Adjustment”.

The holders of shares of 4.5% preferred stock at the close of business on a Record Date will be entitled to receive the dividend payment on those shares on the corresponding Dividend Payment Date notwithstanding the conversion of such shares following that Record Date or our default in payment of the dividend due on that Dividend Payment Date. However, shares of 4.5% preferred stock surrendered for conversion during the period between the close of business on any Record Date and the close of business on the business day immediately preceding the applicable Dividend Payment Date must be accompanied by payment of an amount equal to the dividend payable on such shares on that Dividend Payment Date. A holder of shares of 4.5% preferred stock on a Record Date who (or whose transferee) tenders any shares for conversion on the corresponding Dividend Payment Date will receive the dividend payable by us on the 4.5% preferred stock on that date, and the converting holder need not include payment in the amount of such dividend upon surrender of shares of 4.5% preferred stock for conversion. Except as provided above with respect to a voluntary conversion, we will make no payment or allowance for unpaid dividends, whether or not in arrears, on converted shares or for dividends on the shares of common stock issued upon conversion.

Mandatory Conversion

At any time, we may at our option cause the 4.5% preferred stock to be automatically converted into that number of whole shares of common stock for each share of 4.5% preferred stock equal to $100 (the liquidation preference per share of 4.5% preferred stock) divided by the then prevailing Conversion Price. We may exercise this right only if the Closing Sale Price of our common stock equals or exceeds 130% of the then prevailing Conversion Price for at least 20 Trading Days in a period of 30 consecutive Trading Days, including the last Trading Day of such

30-day period, ending on the Trading Day prior to our issuance of a press release announcing the mandatory conversion as described below.

To exercise the mandatory conversion right described above, we must issue a press release for publication on the Dow Jones News Service prior to the opening of business on the first Trading Day following any date on which the conditions described in the first paragraph of this “Mandatory Conversion” section are met, announcing such a mandatory conversion. We will also give notice by mail or by publication (with subsequent prompt notice by mail) to the holders of the 4.5% preferred stock (not more than four business days after the date of the press release) of the mandatory conversion announcing our intention to convert the 4.5% preferred stock. The conversion date will be a date selected by us (which we will refer to as the “Mandatory Conversion Date”) and will be no more than ten days after the date on which we issue such press release.

In addition to any information required by applicable law or regulation, the press release and notice of a mandatory conversion shall state, as appropriate:

- the Mandatory Conversion Date;

- the number of shares of common stock to be issued upon conversion of each share of 4.5% preferred stock

- the number of shares of 4.5% preferred stock to be converted; and

- that dividends on the 4.5% preferred stock to be converted will cease to accrue on the Mandatory Conversion Date.

On and after the Mandatory Conversion Date, dividends will cease to accrue on the 4.5% preferred stock called for a mandatory conversion and all rights of holders of such 4.5% preferred stock will terminate except for the right to receive the shares of common stock issuable upon conversion thereof. The dividend payment with respect to the 4.5% preferred stock called for a mandatory conversion on a date during the period between the close of business on any Record Date for the payment of dividends to the close of business on the corresponding Dividend Payment Date will be payable on such Dividend Payment Date to the record holder of such share on such Record Date if such share has been converted after such Record Date and prior to such Dividend Payment Date. Except as provided in the immediately preceding sentence with respect to a mandatory conversion, no payment or adjustment will be made upon conversion of 4.5% preferred stock for accumulated and unpaid dividends or for dividends with respect to the common stock issued upon such conversion.

We may not authorize, issue a press release or give notice of any mandatory conversion unless, prior to giving the conversion notice, all accumulated and unpaid dividends on the 4.5% preferred stock for periods ended prior to the date of such conversion notice shall have been paid.

In addition to the mandatory conversion provision described above, if there are fewer than 250,000 shares of 4.5% preferred stock outstanding, we may, at any time and at our option, cause the 4.5% preferred stock to be automatically converted into that number of shares of common stock equal to $100 (the liquidation preference per share of 4.5% preferred stock) divided by the lesser of the then prevailing Conversion Price and the Market Value as determined on the second Trading Day immediately prior to the Mandatory Conversion Date. The provisions of the immediately preceding four paragraphs shall apply to any such mandatory conversion; provided, however, that (1) the Mandatory Conversion Date will not be less than 15 days nor more than 30 days after the date on which we issue a press release announcing such mandatory conversion and (2) the press release and notice of mandatory conversion will not state the number of shares of common stock to be issued upon conversion of each share of 4.5% preferred stock.

Fractional Shares

No fractional shares of common stock or securities representing fractional shares of common stock will be issued upon conversion, whether voluntary or mandatory, or in respect of dividend payments made in common stock on 4.5% preferred stock. Any fractional interest in a share of common stock resulting from conversion will be paid in cash based on the Closing Sale Price at the close of business on the Trading Day next preceding the date of conversion.

Conversion Price Adjustment

The initial Conversion Price of the 4.5% preferred stock was $44.172. The Conversion Price is subject to adjustment (in accordance with formulas set forth in the certificate of designation) in certain events, including:

- any payment of a dividend (or other distribution) payable in shares of common stock on any class of our capital stock other than the 4.5% preferred stock;

- any issuance to all holders of shares of common stock of rights, options or warrants entitling them to subscribe for or purchase shares of common stock or securities convertible into or exchangeable for shares of common stock at less than the Market Value for the period ending on the date of issuance; provided, *however,* that no adjustment shall be made with respect to such a distribution if the holder of shares of 4.5% preferred stock would be entitled to receive such rights, options or warrants upon conversion at any time of shares of 4.5% preferred stock into common stock; *provided further, however,* that if such rights, options or warrants are only exercisable upon the occurrence of certain triggering events, then the Conversion Price will not be adjusted until such triggering events occur;

- any subdivision, combination or reclassification of the common stock;

- any dividend or distribution to all holders of shares of common stock (other than a dividend or distribution referred to in the second bullet point above) made pursuant to any shareholder rights plan, "poison pill" or similar arrangement and excluding dividends payable upon the 4.5% preferred stock;

- any distribution by us consisting exclusively of cash to all holders of our common stock, excluding any cash dividend on our common stock to the extent that the aggregate cash dividend per share of our common stock in any quarterly period does not exceed $0.065 (the "dividend threshold amount"); the dividend threshold amount is subject to adjustment under the same circumstances under which the Conversion Price is subject to adjustment; *provided, however,* that no adjustment will be made to the dividend threshold amount for any adjustment made to the Conversion Price pursuant to this clause, in which event the Conversion Price will be adjusted by multiplying:

  (1) the Conversion Price by

  (2) a fraction, the numerator of which will be the Market Value of a share of our common stock minus the amount per share of such dividend increase (as determined below) or distribution and the denominator of which will be the Market Value of a share of our common stock.

  If an adjustment is required to be made under this clause as a result of a cash dividend in any quarterly period that exceeds the dividend threshold amount, the adjustment would be based upon the amount by which the distribution exceeds the dividend threshold amount (the dividend increase). If an adjustment is otherwise required to be made under this clause, the adjustment would be based upon the full amount of the distribution. Notwithstanding the foregoing, in no event will the Conversion Price be less than $32.72, subject to adjustment in accordance with the first, second, third, fourth, sixth and seventh bullet points under this caption "—Conversion Price Adjustment";

- the completion of a tender or exchange offer made by us or any of our subsidiaries for shares of common stock that involves an aggregate consideration that, together with (a) any cash and other consideration payable in a tender or exchange offer by us or any of our subsidiaries for shares of common stock expiring within the then-preceding 12 months in respect of which no adjustment has been made and (b) the aggregate amount of any such all-cash distributions referred to in the preceding bullet point to all holders of shares of common stock within the then-preceding 12 months in respect of which no adjustments have been made, exceeds 15% of our market capitalization on the expiration of such tender offer; or

- a distribution to all holders of common stock consisting of evidences of indebtedness, shares of capital stock other than common stock or assets (including securities, but excluding those dividends, rights, options, warrants and distributions referred to above).

No adjustment of the Conversion Price will be required unless such adjustment would require an increase or decrease of at least 1.0% of the Conversion Price then in effect. Any lesser adjustment shall be carried forward and shall be made at the time of and together with the next subsequent adjustment, if any, which, together with any adjustment or adjustments so carried forward, shall amount to an increase or decrease of at least 1.0% of such Conversion Price; *provided*, *however*, that with respect to adjustments to be made to the Conversion Price in connection with cash dividends paid by us, we will make such adjustments, regardless of whether such aggregate adjustments amount to 1.0% or more of the Conversion Price, no later than September 15 of each calendar year. We reserve the right to make such reductions in the Conversion Price in addition to those required in the foregoing provisions as we consider to be advisable in order that any event treated for federal income tax purposes as a dividend of stock or stock rights will not be taxable to the recipients. If we elect to make such a reduction in the Conversion Price, we will comply with the requirements of securities laws and regulations thereunder if and to the extent that such laws and regulations are applicable in connection with the reduction of the Conversion Price.

If we distribute rights or warrants (other than those referred to in the second bullet point of the third preceding paragraph) pro rata to holders of shares of common stock, so long as any such rights or warrants have not expired or been redeemed by us, the holder of any 4.5% preferred stock surrendered for conversion will be entitled to receive upon such conversion, in addition to the shares of common stock then issuable upon such conversion (which we will refer to as the “Conversion Shares”), a number of rights or warrants to be determined as follows:

- if such conversion occurs on or prior to the date for the distribution to the holders of rights or warrants of separate certificates evidencing such rights or warrants (which we will refer to as the “Distribution Date”), the same number of rights or warrants to which a holder of a number of shares of common stock equal to the number of Conversion Shares is entitled at the time of such conversion in accordance with the terms and provisions applicable to the rights or warrants; and

- if such conversion occurs after such Distribution Date, the same number of rights or warrants to which a holder of the number of shares of common stock into which such 4.5% preferred stock was convertible immediately prior to such Distribution Date would have been entitled on such Distribution Date had such 4.5% preferred stock been converted immediately prior to such Distribution Date in accordance with the terms and provisions applicable to the rights or warrants.

The Conversion Price will not be subject to adjustment on account of any declaration, distribution or exercise of such rights or warrants.

Following any reclassification, consolidation or merger of our company with or into another person or any merger of another person with or into us (with certain exceptions), or any sale or other disposition of all or substantially all of our assets (computed on a consolidated basis), a holder of a share of 4.5% preferred stock then outstanding will, upon conversion of such 4.5% preferred stock, be entitled to receive the kind and amount of securities, cash and other property receivable upon such reclassification, consolidation, merger, sale or other disposition by a holder of the number of shares of common stock into which such 4.5% preferred stock was convertible immediately prior thereto, after giving effect to any adjustment event. This provision does not limit the rights of holders in the event of a Fundamental Change, including their right to receive the make-whole premium in connection with a conversion.

Payment Upon Conversion Upon a Fundamental Change

We must give notice of each Fundamental Change (as defined below) to all record holders on a date ("the Fundamental Change Notice Date") that is within 10 Trading Days after the effective date of the Fundamental Change (the "Effective Date"). If a holder converts its 4.5% preferred stock at any time beginning at the opening of business on the Trading Day immediately following the Effective Date and ending at the close of business on the 30th Trading Day immediately following the Effective Date, the holder will receive:

- common stock and cash in lieu of fractional shares, as described under "—Conversion Rights" (subject to adjustment as described above under "—Conversion Price Adjustment") and "—Fractional Shares"; and

- the make-whole premium, if any.

Except as provided below, upon a Fundamental Change, holders of 4.5% preferred stock shall, if the Market Value at such time is less than the applicable Conversion Price, also have a one-time option to convert all of their outstanding shares of 4.5% preferred stock into shares of common stock at an adjusted Conversion Price equal to the greater of (1) the Market Value as of the Effective Date and (2) $21.81. This option shall be exercisable during a period of not less than 30 days nor more than 60 days after the Fundamental Change Notice Date. In lieu of issuing the shares of common stock issuable upon conversion in the event of a Fundamental Change, we may, at our option, make a cash payment equal to the Market Value for each share of such common stock otherwise issuable upon conversion or determined for the period ending on the Effective Date.

A "Fundamental Change" will be deemed to have occurred upon the occurrence of any of the following:

- the sale, lease or transfer, in one or a series of related transactions, of all or substantially all of our assets (determined on a consolidated basis) to any person or group (as such term is used in Section 13(d)(3) of the Exchange Act), other than to Permitted Holders (as defined in the certificate of designation);

- the adoption of a plan the consummation of which would result in our liquidation or dissolution;

- the acquisition, directly or indirectly, by any person or group (as such term is used in Section 13(d)(3) of the Exchange Act) other than Permitted Holders, of beneficial ownership (as defined in Rule 13d-3 under the Exchange Act) of more than 50% of the aggregate voting power of our voting stock; *provided, however*, that the Permitted Holders beneficially own (as defined in Rules 13d-3 and 13d-5 under the Exchange Act), directly or indirectly, in the aggregate a lesser percentage of the total voting power of our voting stock than such other person or group and do not have the right or ability by voting power, contract or otherwise to elect or designate for election a majority of our board of directors (for the purposes of this definition, such other person or group shall be deemed to beneficially own any voting stock of a specified corporation held by a parent corporation, if such other person or group is the beneficial owner (as defined above), directly or indirectly, of more than 35% of the voting power of the voting stock of such parent corporation and the Permitted Holders beneficially own (as defined in this proviso), directly or indirectly, in the aggregate a lesser percentage of the voting power of the voting stock of such parent corporation and do not have the right or ability by voting power, contract or otherwise to elect or designate for election a majority of the board of directors of such parent corporation);

- during any period of two consecutive years, individuals who at the beginning of such period comprised our board of directors (together with any new directors whose election by such board of directors or whose nomination for election by our shareholders was approved by a vote of 66 2/3% of our directors then still in office who were either directors at the beginning of such period or whose election or nomination for election was previously so approved) cease for any reason to constitute a majority of our board of directors then in office; or

- our common stock ceases to be listed on a national securities exchange or quoted on Nasdaq or another over-the-counter market in the United States.

However, a Fundamental Change will not be deemed to have occurred in the case of a merger or consolidation, if (i) at least 90% of the consideration (excluding cash payments for fractional shares and cash payments pursuant to dissenters' appraisal rights) in the merger or consolidation consists of common stock of a United States company traded on a national securities exchange or quoted on Nasdaq (or which will be so traded or quoted when issued or exchanged in connection with such transaction) and (ii) as a result of such transaction or transactions the shares of 4.5% preferred stock become convertible solely into such common stock.

The phrase "all or substantially all" of our assets is likely to be interpreted by reference to applicable state law at the relevant time, and will be dependent on the facts and circumstances existing at such time. As a result, there may be a degree of uncertainty in ascertaining whether a sale or transfer is of "all or substantially all" of our assets.

Determination of the Make-Whole Premium

If a Fundamental Change occurs we will pay a make-whole premium upon certain conversions of the 4.5% preferred stock as described above under "— Payment Upon Conversion Upon a Fundamental Change." The make-whole premium will be:

- equal to a percentage of the liquidation preference of the 4.5% preferred stock converted determined by reference to the table below, based on the Effective Date and the price (the "Stock Price") paid, or deemed to be paid, per share of our common stock in the transaction constituting the Fundamental Change, subject to adjustment as described below; and

- in addition to, and not in substitution for, any cash, securities or other assets otherwise due to holders of 4.5% preferred stock upon conversion.

We will pay the make-whole premium solely in shares of our common stock (other than cash in lieu of fractional shares) or in the same form of consideration into which all or substantially all of the shares of our common stock have been converted or exchanged in connection with the Fundamental Change (other than cash paid in lieu of fractional interests in any security or pursuant to dissenters' rights). We will pay cash in lieu of fractional interests in any security or other property delivered in connection with such Fundamental Change. The make-whole premium will be payable on the 35th Trading Day following the Effective Date for 4.5% preferred stock converted in connection with a Fundamental Change. If holders of our common stock receive or have the right to receive more than one form of consideration in connection with such Fundamental Change, then, for purposes of the foregoing, the forms of consideration in which the make-whole premium will be paid will be in proportion to the relative value, determined as described below, of the different forms of consideration paid to our common shareholders in connection with the Fundamental Change.

The Stock Price paid, or deemed paid, per share of our common stock in the transaction constituting the Fundamental Change will be calculated as follows:

(1) In the case of a Fundamental Change in which all or substantially all of the shares of our common stock have been, as of the Effective Date, converted into or exchanged for the right to receive securities or other assets or property, the consideration shall be valued as follows:

(a) securities that are traded on a U.S. national securities exchange or approved for quotation on the Nasdaq or any similar system of automated dissemination of quotations of securities prices, will be valued at the average of the closing prices of such securities for the five consecutive Trading Days beginning on the second Trading Day after the Fundamental Change Notice Date,

(b) other securities, assets or property, other than cash, that holders will have the right to receive will be valued based on the average of the fair market value of the securities, assets or property, other than cash, as determined by two independent nationally recognized investment banks, and

(c) 100% of any cash.

(2) In all other cases, the value of our common stock will equal the average of the closing prices of our common stock for the five consecutive Trading Days beginning on the second Trading Day after the Fundamental Change Notice Date.

The value of our common stock or other consideration for purposes of determining the number of shares of common stock or other consideration to be issued in respect of the make-whole premium will be calculated in the same manner, except that to the extent such value is calculated pursuant to clause (1)(a), (1)(b) or (2), such value shall be multiplied by 97%.

Certain Definitions Relating to the 4.5% Preferred Stock

"*Closing Sale Price*" of our common stock on any date means the closing sale price per share (or if no closing sale price is reported, the average of the closing bid and ask prices or, if more than one in either case, the average of the average closing bid and the average closing ask prices) on such date as reported on the principal United States securities exchange on which our common stock is traded or, if our common stock is not listed on a United States national or regional securities exchange, as reported by Nasdaq or by the National Quotation Bureau Incorporated. In the absence of such a quotation, the Closing Sale Price will be an amount determined in good faith by our board of directors to be the fair value of the common stock.

"*Dividend Payment Date*" means March 15, June 15, September 15 and December 15 of each year, commencing December 15, 2005.

"*Junior Stock*" means all classes of common stock of the Company and each other class of capital stock or series of preferred stock established after the issue date, by the board of directors, the terms of which do not expressly provide that such class or series ranks senior to or on parity with the preferred stock as to dividend rights or rights upon the liquidation, winding-up or dissolution of the Company.

"*Market Value*" means the average Closing Sale Price of the common stock for a five consecutive Trading Day period on the New York Stock Exchange (or such other national securities exchange or automated quotation system on which the common stock is then listed or authorized for quotation or, if not so listed or authorized for quotation, an amount determined in good faith by our board of directors to be the fair value of the common stock) ending immediately prior to the date of determination.

"*Parity Stock*" means any class of capital stock or series of preferred stock established after the issue date by the board of directors, the terms of which expressly provide that such class or series will rank on parity with the Preferred Stock as to dividend rights or rights upon the liquidation, winding-up or dissolution of the Company.

"*Trading Day*" means a day during which trading in securities generally occurs on the New York Stock Exchange or, if our common stock is not listed on the New York Stock Exchange, on the principal other national or regional securities exchange on which our common stock is then listed or, if our common stock is not listed on a national or regional securities exchange, on Nasdaq or, if our common stock is not quoted on Nasdaq, on the principal other market on which our common stock is then traded.

Anti-Takeover Provisions

Our certificate of incorporation and bylaws and the Oklahoma General Corporation Act (the "OGCA") include a number of provisions which may have the effect of encouraging persons considering unsolicited tender offers or other unilateral takeover proposals to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. These provisions could delay or prevent entirely a merger or acquisition that our shareholders consider favorable. These provisions may also discourage acquisition proposals or have the effect of delaying or preventing entirely a change in control, which could harm our stock price. Following is a description of the anti-takeover effects of certain provisions of our certificate of incorporation and of our bylaws.

Oklahoma Business Combination Statute. Section 1090.3 of the OGCA prevents certain Oklahoma corporations from engaging in a "business combination" with an "interested shareholder" for three years following the date the person became an interested shareholder, unless:

- before the person became an interested shareholder, the board of directors of the corporation approved the business combination or transaction in which the person became an interested shareholder;

- upon consummation of the transaction that resulted in the person becoming an interested shareholder, the interested shareholder owned stock having at least 85% of all voting power of the corporation when the transaction commenced, excluding for purposes of determining the outstanding voting stock, but not the outstanding voting stock owned by the interested shareholder, stock held by directors who are also officers of the corporation and stock held by certain employee stock plans; or

- after the person became an interested shareholder, the business combination is approved by the board of directors of the corporation and authorized at a meeting of shareholders, and not by written consent, by the affirmative vote of the holders of at least two-thirds of all voting power not attributable to shares owned by the interested shareholder.

Section 1090.3 defines a "business combination" to include:

- any merger or consolidation involving the corporation and an interested shareholder;

- any sale, lease, exchange, mortgage, pledge, transfer or other disposition to or with an interested shareholder of 10% or more of the assets of the corporation;

- subject to certain exceptions, any transaction which results in the issuance or transfer by the corporation of any stock of the corporation to an interested shareholder;

- any transaction involving the corporation which has the effect of increasing the proportionate share of the stock of any class or series or voting power of the corporation owned by the interested shareholder;

- the receipt by an interested shareholder of the benefit of any loans, advances, guarantees, pledges or other financial benefits provided by or through the corporation; or

- any share acquisition by the interested shareholder pursuant to Section 1090.1 of the OGCA.

For purposes of Section 1090.3, the term "corporation" also includes the corporation's direct and indirect majority-owned subsidiaries.

Section 1090.3 defines an "interested shareholder" generally as any person that owns stock having 15% or more of all voting power of the corporation, any person that is an affiliate or associate of the corporation and owned stock having 15% or more of all voting power of the corporation within the three-year period before the time of determination of interested shareholder status, and any affiliate or associate of such person.

Section 1090.3 applies to Oklahoma corporations whose voting stock is listed on a national securities exchange and that have not elected to opt out of the section. A corporation may elect not to be governed by an amendment to its certificate of incorporation or bylaws authorized by its board of directors and approved by a majority vote of all outstanding voting stock. Any such amendment would be effective 12 months after adoption and would not apply to a business combination between the corporation and a person who became an interested shareholder before adoption of the amendment.

Oklahoma Control Share Statute. Our certificate of incorporation provides that we are not subject to the control share provisions of the OGCA. With exceptions, these provisions prevent holders of more than 20% of the voting power of the stock of an Oklahoma corporation from voting their shares. If we were to become subject to the control share provisions of the OGCA in the future, this provision could delay the time it takes anyone to gain control of us.

Stock Purchase Provisions. Our certificate of incorporation includes a provision that requires the affirmative vote of no less than two-thirds of the votes cast by the holders, voting together as a single class, of all then outstanding shares of capital stock, excluding the votes by an interested shareholder, unless a greater vote is required by law, to approve the purchase by us of any of our capital stock from the interested shareholder who has beneficially owned such capital stock for less than three years prior to the date of such purchase, or any agreement in respect thereof, at a price in excess of fair market value, unless the purchase is either (a) a purchase or other acquisition of securities of the same class made on substantially the same terms to all holders of the same securities and complying with the applicable requirements of the Exchange Act or (b) made on the open market and not the result of a privately negotiated transaction.

Calling of Special Meetings of Shareholders. Our bylaws provide that special meetings of our shareholders may be called only by the chairman of the board, the chief executive officer or by the president or secretary, at the request, in writing, of a majority of the directors then in office.

Advance Notice Requirements for Shareholder Proposals and Director Nominations. Our bylaws provide that shareholders seeking to nominate candidates for election as directors or to bring business before an annual meeting of shareholders must provide timely notice of their proposal in writing to our corporate secretary. Nominations of persons for election to the board of directors of the corporation may only be made at an annual meeting of shareholders. Generally, to be timely, a shareholder’s notice (other than a notice submitted in order to include a shareholder nominee in our proxy materials) must be delivered to our secretary 90 to 120 days before the first anniversary of the previous year’s annual meeting. In order to include a shareholder nominee in our proxy materials, notice must generally be delivered to our secretary 120 to 150 days before the first anniversary of the previous year’s annual meeting. Our bylaws also specify requirements as to the form and content of a shareholder’s notice and describe in detail the information that a shareholder must provide about itself and its nominees. These provisions may impede shareholders’ ability to bring matters before an annual meeting of shareholders or make nominations for directors at an annual meeting of shareholders.

Shareholder Action

Except as otherwise provided by law or in our certificate of incorporation, bylaws, any stock exchange requirement or any certificate of designation, the approval by holders of a majority of the shares of common stock present in person or represented by proxy at a meeting at which a quorum is present and voting is sufficient to authorize, affirm, ratify or consent to a matter voted on by shareholders.

Our bylaws provide that director nominees must receive more votes “for” than “against” to be elected or continue in office. For any other matter submitted to shareholders, the matter will be decided by a majority of the votes cast, unless otherwise required by law, our certificate of incorporation, stock exchange requirements or any certificate of designation. The OGCA requires the approval of the holders of a majority of the outstanding stock entitled to vote for certain extraordinary corporate transactions, such as a merger, sale of substantially all assets, dissolution or amendment of the certificate of incorporation. Our certificate of incorporation provides for the affirmative vote of the holders of at least a majority of the issued and outstanding stock having voting power, voting as a single class, to amend, repeal or adopt any provision inconsistent with the provisions of the certificate of incorporation limiting director liability or stock purchases by us, and providing for the annual election of all directors of the Company and indemnity for our directors, officers, employees and agents. The same vote is also required for shareholders to adopt, repeal, alter, amend or rescind amend, repeal or adopt any provision of our bylaws.

Under our certificate of incorporation and bylaws, shareholders may take actions without the holding of a meeting by written consent or consents signed by the holders of a sufficient number of shares to approve the transaction had all of the outstanding shares of our capital stock entitled to vote thereon been present at a meeting. Our bylaws contain provisions for the form of written consents, their execution and delivery, and their review and tabulation by an independent inspector appointed by the Company. There is also a detailed provision for determining a record date for action by written consent.

Transfer Agent and Registrar

Computershare Trust Company, N.A. is the transfer agent and registrar for our common stock and outstanding preferred stock.

DESCRIPTION OF DEBT SECURITIES

The following description of the Company's 6.625% Senior Notes due 2020 (the "6.625% Notes"), 6.875% Senior Notes due 2020 (the "6.875% Notes"), 6.125% Senior Notes due 2021 (the "6.125% Notes"), 5.375% Senior Notes due 2021 (the "5.375% Notes"), 4.875% Senior Notes due 2026 (the "4.875% Notes") and 5.75% Senior Notes due 2023 (the "5.75% Notes," and together with the 6.625% Notes, the 6.875% Notes, the 6.125% Notes, the 5.375% Notes and the 4.875% Notes, the "Notes") is a summary and does not purport to be complete. This description is qualified in its entirety by reference to (i) the indenture, dated November 8, 2005 (as amended or supplemented, the "2005 Indenture"), among the Company, as issuer, the subsidiary guarantors party thereto and the Bank of New York Mellon Trust Company, N.A. ("BNYM"), as trustee, (ii) the indenture, dated August 2, 2010 (as amended or supplemented, the "2010 Indenture"), among the Company, as issuer, the subsidiary guarantors party thereto and BNYM, as trustee, and (iii) the indenture, dated April 24, 2014 (as amended or supplemented, the "2014 Indenture," and together with the 2010 Indenture and the 2005 Indenture, the "Indentures"), among the Company, as issuer, the subsidiary guarantors party thereto and Deutsche Bank Trust Company Americas, as trustee, which we have filed or incorporated by reference as exhibits to Chesapeake's Annual Report on Form 10-K.

The Notes

The 6.875% Notes were issued under the 2005 Indenture, which provides that debt securities may be issued under the 2005 Indenture from time to time. The 2005 Indenture does not limit the amount of debt securities that the Company may issue under the 2005 Indenture. The Company may issue additional notes having the same terms as the existing 6.875% Notes, except for the date of issuance and issue price. Any additional notes, together with the existing 6.875% Notes, will constitute a single series of notes and will vote together as one class on all matters with respect to such series of 6.875% Notes; provided, however, that the Company may only issue additional notes under the 2005 Indenture if such additional notes are fungible with the existing 6.875% Notes for all United States federal income tax purposes.

The 6.625% Notes, 6.125% Notes, 5.375% Notes and 5.75% Notes were issued under the 2010 Indenture, and the 4.875% Notes were issued under the 2014 Indenture. Both the 2010 Indenture and 2014 Indenture provide that debt securities may be issued under such Indenture from time to time in one or more series. Neither of the 2010 or 2014 Indentures limit the amount of debt securities that the Company may issue under such Indenture. The Company may, without the consent of the holders of any series Notes previously issued under either the 2010 or 2014 Indentures, reopen any series of Notes issued under such Indenture for increases in aggregate principal amount of such series of Notes and issuances additional notes of such series or for the establishment of additional terms with respect to the Notes of such series.

The 6.875% Notes. On November 8, 2005, we issued $500 million in aggregate principal amount of 6.875% senior notes due 2020. The 6.875% Notes mature November 15, 2020, and bear interest at 6.875% per annum. Interest is payable semi-annually on May 15 and November 15 of each year. The 6.875% Notes were offered and sold to the initial purchasers in a transaction exempt from the registration requirements of the Securities Act. In an exchange offer that expired in June 2006, we exchanged all of the $500 million outstanding principal amount of 6.875% Notes for an equal amount of notes with substantially similar terms as the then-outstanding 6.875% Notes, except that the transfer restrictions, registration rights and additional interest provisions no longer apply. As of December 31, 2019, $93 million aggregate principal amount of the 6.875% Notes was outstanding.

The 6.625% Notes. On August 17, 2010, we issued $1.4 billion in aggregate principal amount of 6.625% senior notes due 2020. The 6.625% Notes mature August 15, 2020, and bear interest at 6.625% per annum. Interest is payable semi-annually on February 15 and August 15 of each year. As of December 31, 2019, $208 million aggregate principal amount of the 6.625% Notes was outstanding.

The 6.125% Notes. On February 11, 2011, we issued $1.0 billion in aggregate principal amount of 6.125% senior notes due 2021. The 6.125% Notes mature February 15, 2021, and bear interest at 6.125% per annum. Interest is payable semi-annually on February 15 and August 15 of each year. As of December 31, 2019, $167 million aggregate principal amount of the 6.125% Notes was outstanding.

The 5.375% Notes. On April 1, 2013, we issued $700 million in aggregate principal amount of 5.375% senior notes due 2021. The 5.375% Notes mature June 15, 2021, and bear interest at 5.375% per annum. Interest is payable semi-annually on June 15 and December 15 of each year. As of December 31, 2019, $127 million aggregate principal amount of the 5.375% Notes was outstanding.

The 5.75% Notes. On April 1, 2013, we issued $1.1 billion in aggregate principal amount of 5.75% senior notes due 2023. The 5.75% Notes mature March 15, 2023, and bear interest at 5.75% per annum. Interest is payable semi-annually on March 15 and September 15 of each year. As of December 31, 2019, $209 million aggregate principal amount of the 5.75% Notes was outstanding.

The 4.875% Notes. On April 24, 2014, we issued $1.5 billion in aggregate principal amount of 4.875% senior notes due 2022. The 4.875% Notes mature April 15, 2022, and bear interest at 4.875% per annum. Interest is payable semi-annually on April 15 and October 15 of each year. As of December 31, 2019, $338 million aggregate principal amount of the 5.75% Notes was outstanding.

Guarantees

The Notes are general unsecured senior obligations of ours, are guaranteed by our material subsidiaries (other than Brazos Valley Longhorn, L.L.C. (“BVL”) and its subsidiaries) and are effectively subordinated to any of our secured indebtedness to the extent of the value of the collateral securing such indebtedness and to the indebtedness of BVL and its subsidiaries. In the future, the guarantees may be released and terminated under certain circumstances.

Ranking

The Notes rank equally in right of payment with all existing and future senior indebtedness of the Company and senior in right of payment to all of the Company’s future subordinated indebtedness. The Notes are effectively subordinated to the Company’s secured indebtedness, if any, to the extent of the value of the assets securing such indebtedness and are structurally subordinated to all liabilities of any of the Company’s subsidiaries that are not guarantors.

Each guarantee of the Notes is a general unsecured senior obligation of that guarantor, ranks equally in right of payment with all existing and future senior indebtedness of that guarantor and senior in right of payment to any future subordinated indebtedness of that guarantor. Each guarantee of the Notes is effectively subordinated to any existing and future secured indebtedness of that guarantor to the extent of the value of any collateral securing such indebtedness and is structurally subordinated to all liabilities of any of such guarantor's subsidiaries that are not themselves guarantors.

Payment on the Notes

We will pay the principal of, and any premium and interest on, the Notes of such series on the dates and in the manner provided in the terms of the Notes of such series and the applicable Indenture. Principal or redemption price, and any premium and interest with respect to a series of Notes, will be considered paid on the date due if the trustee or Paying Agent holds on that date money deposited by the Company designated for and sufficient to pay such principal, redemption price, premium and interest as is then due with respect to such series of Notes.

We will pay interest (including post-petition interest in any proceeding under any Bankruptcy Law) on overdue principal, and any premium, at the rate borne by the Notes of such series to the extent lawful; and we will pay interest (including post-petition interest in any proceeding under any Bankruptcy Law) on overdue installments of interest (without regard to any applicable grace period) at the same rate to the extent lawful.

Optional Redemption

General

The indentures governing the 6.875% Notes, 6.625% Notes, 6.125% Notes and 5.75% Notes provide that we may redeem all or part of the such Notes at a redemption price equal to the Make-Whole Price (as defined in such Indenture) plus accrued and unpaid interest on the Notes so redeemed to the date of redemption.

The indenture governing the 5.375% Notes provides that we may redeem all or part of the 5.375% Notes at par plus accrued and unpaid interest.

The indenture governing the 4.875% Notes provides that we may redeem all or part of the 4.875% Notes at redemption prices equal to 101.219% on or after April 15, 2019 and 100.000% on or after April 15, 2020, in each case, of the principal amount redeemed, plus accrued and unpaid interest.

Selection and Notice

If less than all of the Notes of a series are to be redeemed at any time, the trustee will select the particular Notes of such series to be redeemed pro rata or by lot or, if the Notes of such series are listed on any securities exchange, by any other method that complies with the requirements of such exchange; provided, however, that no Notes with a principal amount of $1,000 or less in the case of Notes issued under the 2005 or 2010 Indentures or $2,000 or less in the case of Notes issued under the 2014 Indenture will be redeemed in part. The trustee will make the selection from outstanding securities of such series not previously called for redemption not less than 30 nor more than 60 days prior to the redemption date. Notes and portions of them it selects will be in amounts of $1,000 or whole multiples of $1,000 in the case of Notes issued under the 2005 or 2010 Indentures, and $2,000 or integral multiples of $1,000 in excess thereof in the case of Notes issued under the 2014 Indenture. Provisions of the Indentures that apply to Notes of any series called for redemption also apply to portions of Notes of such series called for redemption.

At least 30 days but not more than 60 days before a redemption date, the Company must mail a notice of redemption by first-class mail to each holder of Notes to be redeemed at such holder's registered address or send such notice in accordance with the Depositary's applicable procedures. If any security is being redeemed in part, the notice of redemption must state the portion of the principal amount of such security to be redeemed and, if applicable, that a new Note or Notes in principal amount equal to the unredeemed portion will be issued in the name of the holder thereof upon cancellation of the Note or Notes being redeemed. Under the 2010 and 2014 Indentures, if fewer than all of the outstanding Notes of a series are to be redeemed, the notice of redemption also must identify the particular Notes to be redeemed.

Certain Covenants

Limitation on Liens Securing Certain Indebtedness

Under the 2010 and 2014 Indentures, the Company (1) will not, and will not permit any Restricted Subsidiary to, create, incur or assume any Funded Debt secured by any Liens (other than Permitted Liens) upon any of the properties of the Company or any Restricted Subsidiary and (2) will not, and will not permit any Subsidiary to, create, incur or assume any Funded Debt secured by any Liens (other than Permitted Liens) upon the Capital Stock of any Restricted Subsidiary or the Capital Stock of any Subsidiary that owns, directly or indirectly through ownership in another Subsidiary, the Capital Stock of any Restricted Subsidiary, unless (as to each of clauses (1) and (2)) the notes or the Guarantee (if any) of such Restricted Subsidiary, as applicable, (together with, if the Company so determines, any other indebtedness or other obligation of the Company or such Restricted Subsidiary which is not subordinate in right of payment to the prior payment in full of the Notes issued thereunder) are equally and ratably secured for so long as such Funded Debt is so secured; provided, that if such Funded Debt is expressly subordinated to such Notes or a related Guarantee, if any, the Lien securing such Funded Debt will be subordinated and junior to the Lien securing such Notes or such Guarantee. Notwithstanding the foregoing provisions, the Company or any Subsidiary may create, incur or assume Funded Debt secured by Liens which would otherwise be subject to the restrictions of such section, if the aggregate principal amount of such Funded Debt and all other Funded Debt of the Company and any Subsidiary theretofore created, incurred or assumed pursuant to the exception in this sentence and outstanding at such time does not exceed 15% of the Adjusted Consolidated Net Tangible Assets of the Company (the “Secured Debt Basket”).

Under the 2005 Indenture, the Company will not, and will not permit any Subsidiary to, create, incur or assume any Indebtedness secured by any Liens (other than Permitted Liens) upon any of the properties of the Company or any Subsidiary, unless the 6.875% Notes or a Guarantee are equally and ratably secured; provided, that if such Indebtedness is expressly subordinated to such Notes or a Guarantee, the Lien securing such Indebtedness will be subordinated and junior to the Lien securing such Notes or such Guarantee.

Limitations on Sale/Leaseback Transactions

The Company will not, and generally will not permit its subsidiary guarantors, in the case of the 2005 Indenture, or its Restricted Subsidiaries, in the case of the 2010 and 2014 Indentures, to, enter into any Sale/Leaseback Transaction with any Person (other than the Company or any other subsidiary) unless:

(1) the Company or such subsidiary would be entitled to incur Funded Debt or Indebtedness, as the case may be, secured by Liens in a principal amount equal to the Attributable Indebtedness (under the 2010 and 2014 Indentures, treated as if such Attributable Indebtedness were Funded Debt) with respect to such Sale/Leaseback Transaction; provided, however, that, under the 2010 and 2014 Indentures, Attributable Indebtedness in respect of any Sale/Leaseback Transaction entered into pursuant to this clause will not count against the amount of Funded Debt or permitted under the Secured Debt Basket for any other purpose, including when determining the amount available thereunder for future Sale/Leaseback Transactions or any Funded Debt transactions; or

(2) the Company or such Restricted Subsidiary receives proceeds from such Sale/Leaseback Transaction at least equal to the fair market value thereof (as determined in good faith by the Company) and such proceeds are applied in accordance with the following two paragraphs.

The Company may apply Net Available Proceeds from such Sale/Leaseback Transaction, within 365 days following the receipt of Net Available Proceeds from the Sale/Leaseback Transaction, to:

(1) the repayment of Indebtedness of the Company or a Restricted Subsidiary under Credit Facilities or other Senior Indebtedness, including any redemption or repurchase of existing notes or the Notes;

(2) make an Investment in assets used or useful in the Oil and Gas Business (including Capital Stock of Persons engaged in the Oil and Gas Business); or

(3) develop by drilling the Company's oil and gas reserves.

If, upon completion of the 365-day period, any portion of the Net Available Proceeds has not been applied by the Company as described in clauses (1), (2) or (3) in the immediately preceding paragraph and such remaining Net Available Proceeds, together with any remaining net cash proceeds from any prior Sale/Leaseback Transaction (such aggregate constituting "Excess Proceeds"), exceed \$40 million under the 2005 Indenture or \$60 million under the 2010 or 2014 Indenture, then the Company will be obligated to make an offer (the "Net Proceeds Offer") to purchase the Notes and any other Senior Indebtedness in respect of which such an offer to purchase is also required to be made concurrently with the Net Proceeds Offer having an aggregate principal amount equal to the Excess Proceeds (such purchase to be made on a pro rata basis if the amount available for such repurchase is less than the principal amount of the Notes and other such Senior Indebtedness tendered in such Net Proceeds Offer) at a purchase price of 100% of the principal amount thereof plus accrued interest thereon to the date of repurchase. Upon the completion of the Net Proceeds Offer, the amount of Excess Proceeds will be reset to zero.

Limitations on Mergers and Consolidations

The Indentures provide that we will not consolidate or merge with or into any Person, or sell, convey, lease or otherwise dispose of all or substantially all of our assets to any Person, unless: (1) the Person formed by or surviving such consolidation or merger (if other than us), or to which such sale, lease, conveyance or other disposition is made (collectively, the "successor"), is a corporation, limited liability company, general partnership (in the case of the 2010 and 2014 Indentures) or limited partnership organized and existing under the laws of the United States or any state thereof or the District of Columbia, and the successor assumes by supplemental indenture in a form satisfactory to the applicable trustee all of our obligations under the applicable Indenture and Notes; provided, that unless the successor is a corporation, a corporate co-issuer of the Notes will be added to such Indenture by a supplemental indenture; and (2) immediately after giving effect to such transaction, no Event of Default will have occurred and be continuing.

Upon any such consolidation, merger, lease, conveyance or transfer, the applicable trustee will be notified by us or the successor, and the successor formed by such consolidation or into which we are merged or to which such lease, conveyance or transfer is made will succeed to, and be substituted for, and may exercise every right and power of, ours under the applicable Indenture with the same effect as if such successor had been named as the Company under such Indenture and thereafter (except in the case of a lease) we will be relieved of all further obligations and covenants under such Indenture and the Notes issued thereunder.

SEC Reports.

We will, within 15 days after we file the same with the SEC, deliver to the holders of Notes issued under an Indenture or the applicable trustee copies of the annual reports and the information, documents and other reports (or copies of any such portions of any of the foregoing as the SEC may by rules and regulations prescribe) that we are required to file with the SEC pursuant to Section 13 or 15(d) of the Exchange Act; provided that, under the 2010 and 2014 Indentures, any such annual reports, information, documents or other reports filed or furnished with the SEC pursuant to its Electronic Data Gathering, Analysis and Retrieval (or "EDGAR") system will be deemed to be delivered to the trustee as of the time such information, documents or reports are filed or furnished via EDGAR; provided, however, that the trustee under the 2014 Indenture has no obligation whatsoever to determine whether or not such information, documents or reports have been filed pursuant to the EDGAR system (or its successor).

Notwithstanding that we may not be required to remain subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act, we will file with the SEC (to the extent such filings are accepted by the SEC) and provide the trustee with such annual reports and such information, documents and other reports specified in Sections 13 and 15(d) of the Exchange Act, subject in certain cases to the proviso in the immediately preceding sentence.

Events of Default

The following are “Events of Default” with respect to Notes issued under an Indenture:

1. default by the Company or any subsidiary guarantor in the payment of principal of or any premium on such Notes when due and payable at Maturity and, in the case of Notes issued under the 2005 Indenture, upon a failure to repurchase pursuant to such Indenture, upon acceleration or otherwise;

2. default by the Company or any subsidiary guarantor in the payment of any installment of interest on such Notes when due and payable and continuance of such default for 30 days;

3. default by the Company or any subsidiary guarantor with respect to any other Indebtedness of the Company or any subsidiary guarantor if either

   a. such default results in the acceleration of the maturity of certain indebtedness having a principal amount of $50.0 million or more under the 2005 Indenture or $75.0 million or more under the 2010 and 2014 Indentures, individually or, taken together with the principal amount of any other such Indebtedness the maturity of which has been so accelerated, in the aggregate, or

   b. such default results from the failure to pay when due principal of any such Indebtedness, after giving effect to any applicable grace period (a “Payment Default”), having a principal amount of $50.0 million or more under the 2005 Indenture or $75.0 million or more under the 2010 and 2014 Indentures individually or, taken together with the principal amount of any other Indebtedness under which there has been a Payment Default, in the aggregate;

   provided that if any such default is cured or waived or any such acceleration is rescinded, or such indebtedness is repaid, within a period of 30 days from the continuation of such default beyond any applicable grace period or the occurrence of such acceleration, as the case may be, such Event of Default and any consequent acceleration of such Notes will be rescinded, so long as any such rescission does not conflict with any judgment or decree or applicable provision of law;

4. default in the performance, or breach of, any covenant or agreement of the Company or any subsidiary guarantor in the applicable Indenture governing such Notes and, in each such case, failure to remedy such default within a period of 60 days after written notice thereof from the applicable trustee or holders of 25% of the principal amount of the applicable Notes; provided, however, that under the 2010 and 2014 Indentures, the Company will have 90 days following such written notice to remedy or receive a waiver for any failure to comply with its obligations under such Indenture so long as the Company is attempting to remedy any such failure as promptly as reasonably practicable;

5. the failure of a Guarantee by a subsidiary guarantor to be in full force and effect, or the denial or disaffirmance by such entity thereof; or

6. certain events involving bankruptcy, insolvency or reorganization of the Company or any subsidiary guarantor.

The following are additional Events of Default with respect to the 6.875% Notes issued under the 2005 Indenture:

1. default by the Company or any subsidiary guarantor in the deposit of any make-whole redemption payment when and as due and payable; and

2. the entry by a court of one or more judgments or orders for the payment of money against the Company, any subsidiary guarantor or other subsidiary in an aggregate amount in excess of $50.0 million that has not been vacated, discharged, satisfied or stayed pending appeal within 60 days from the entry thereof.

Each Indenture provides that the applicable trustee may withhold notice to the holders of the Notes issued thereunder of any default (except in payment of principal of, or any premium or interest on, any such Note) if such trustee determines in good faith that it is in the interest of the holders of such Notes to do so.

If an Event of Default occurs and is continuing with respect to Notes issued under an Indenture, the applicable trustee or the holders of not less than 25% in principal amount of such outstanding Notes may declare the unpaid principal of, and any premium and accrued but unpaid interest on, all such Notes then outstanding to be due and payable. Upon such a declaration, such principal (or other specified amount), and any premium and interest will be due and payable immediately. If an Event of Default relating to certain events of bankruptcy, insolvency or reorganization of the Company or any subsidiary guarantor occurs and is continuing, the principal of, and any premium and interest on, all such Notes will become and be immediately due and payable without any declaration or other act on the part of the applicable trustee or any holder. Under certain circumstances, the holders of a majority in principal amount of the outstanding Notes issued under an Indenture with respect to which a declaration of acceleration has been made may rescind any such acceleration with respect to such Notes and its consequences.

No holder of Notes may pursue any remedy under the applicable Indenture unless:

(1) the applicable trustee has received written notice of a continuing Event of Default,

(2) the applicable trustee has received a request from holders of at least 25% in principal amount of such Notes to pursue such remedy,

(3) the applicable trustee has been offered indemnity reasonably satisfactory to it,

(4) the applicable trustee has failed to act for a period of 60 days after receipt of such notice, request and offer of indemnity, and

(5) no direction inconsistent with such written request has been given to the applicable trustee during such 60-day period by the holders of a majority in principal amount of such Notes;

provided, however, that holders of any of the Notes issued under an Indenture have the absolute and unconditional right to receive payment of the principal of and any interest due on any of such Notes and to institute suit for the enforcement of any such payment notwithstanding any other provisions of the applicable Indenture.

The holders of a majority in principal amount of the outstanding Notes issued under an Indenture will have the right to direct the time, method and place of conducting any proceeding for exercising any remedy available to the applicable trustee, subject to certain limitations specified in the applicable Indenture. The trustee is under no obligation and may refuse to perform any duty or exercise any right, duty or power under the applicable Indenture unless it receives indemnity reasonably satisfactory to it against any loss, liability, claim, damage or expense.

Legal Defeasance and Covenant Defeasance

The Company may, at its option and at any time, elect to have its obligations discharged with respect to the Notes issued under an Indenture (“Legal Defeasance”). Such Legal Defeasance means that the Company and any subsidiary guarantor will be deemed to have paid and discharged the entire indebtedness represented by such outstanding Notes and any Guarantees thereof, except for:

(1) the rights of holders of such outstanding Notes to receive payments solely from the trust fund described in the applicable Indenture in respect of the principal of, and any premium and interest on, such Notes when such payments are due;

(2) the Company's obligations with respect to such Notes concerning the issuance of temporary notes, transfers and exchanges of such Notes, replacement of mutilated, destroyed, lost or stolen Notes, the maintenance of an office or agency where such Notes may be surrendered for transfer or exchange or presented for payment, and duties of paying agents;

(3) the rights, powers, trusts, duties and immunities of the applicable trustee, and the Company's obligations in connection therewith; and

(4) the Defeasance provisions of such Indenture.

In addition, the Company may, at its option and at any time, elect to have the obligations of the Company under the Notes issued under an Indenture released with respect to certain covenants, and thereafter any omission to comply with such obligations will not constitute a Default or Event of Default with respect to such Notes. In the event Covenant Defeasance with respect to such Notes occurs, certain events (not including non-payment) described under "—Events of Default" will no longer constitute an Event of Default with respect to such Notes. If we exercise our Legal Defeasance or Covenant Defeasance option with respect to any of the Notes, each subsidiary guarantor will be released from all its obligations under the applicable Indenture and its Guarantee of such Notes.

In order to exercise either Legal Defeasance or Covenant Defeasance under the Indentures:

(1) the Company must irrevocably deposit with the applicable trustee, in trust, for the benefit of the holders of such Notes, cash in U.S. Legal Tender, U.S. Government Securities, or a combination thereof, in such amounts as will be sufficient, in the opinion of a nationally recognized firm of independent public accountants, to pay the principal of, and any premium, if any, and interest on, such outstanding Notes on each date on which such principal and any premium and interest is due and payable under such Indenture or on any redemption date established pursuant to such Indenture (provided that, upon any redemption that requires the payment of a Make-Whole Premium, (x) the amount of cash, U.S. Government Securities, or combination thereof, that must be deposited will be determined using an assumed applicable premium calculated as of the date of such deposit and (y) the Company will deposit any deficit in trust on or prior to the redemption date as necessary to pay the applicable premium as determined by such date);

(2) in the case of Legal Defeasance, the Company must deliver to the trustee an opinion of counsel reasonably acceptable to the trustee confirming that (i) the Company has received from or there has been published by the Internal Revenue Service a ruling or (ii) since the date of the applicable Indenture, there has been a change in the applicable federal income tax law, in either case to the effect that , and based thereon such opinion of counsel shall confirm that, the holders of such outstanding Notes will not recognize income, gain or loss for U.S. Federal income tax purposes as a result of such Legal Defeasance and will be subject to U.S. Federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Legal Defeasance had not occurred;

(3) in the case of Covenant Defeasance, the Company must deliver to the applicable trustee an opinion of counsel reasonably acceptable to the trustee to the effect that the holders of such outstanding Notes will not recognize income, gain or loss for U.S. Federal income tax purposes as a result of such Covenant Defeasance and will be subject to federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Covenant Defeasance had not occurred;

(4) the Company must deliver to the applicable trustee an officers' certificate stating that the deposit was not made by the Company with the intent of preferring the holders of such Notes over other creditors of the Company or with the intent of defeating, hindering, delaying or defrauding creditors of the Company or others;

(5) the Company must deliver to the applicable trustee an officers' certificate and an opinion of counsel each stating that the Company has complied with all conditions precedent to the Legal Defeasance or the Covenant Defeasance, as the case may be;

(6) no Default or Event of Default has occurred and is continuing on the date of such deposit or insofar as Events of Default from bankruptcy or insolvency events are concerned, at any time in the period ending on the 91st day after the date of deposit;

(7) such Legal Defeasance or Covenant Defeasance does not result in a breach or violation of, or constitute a default under, any other material agreement, other than the applicable Indenture, or instrument to which the Company is a party or by which the Company is bound.

Satisfaction and Discharge

Under the 2010 and 2014 Indentures, the Company may discharge all its obligations under such Indentures with respect to the applicable Notes, other than its obligation to register the transfer and exchange of such Notes, provided that it either:

(1) delivers all such outstanding Notes to the applicable trustee for cancellation; or

(2) all such Notes not so delivered for cancellation have either become due and payable or will become due and payable at their maturity within one year or are called for redemption within one year, and in the case of this Section (2) the Company has deposited with the trustee in trust an amount of cash sufficient to pay the entire indebtedness of such Notes, including any premium and interest to the Maturity Date or applicable redemption date (provided that, upon any redemption that requires the payment of a Make-Whole Premium, (x) the amount of cash that must be deposited will be determined using an assumed applicable premium calculated as of the date of such deposit and (y) the Company will deposit any deficit in trust on or prior to the redemption date as necessary to pay the applicable premium as determined by such date).

Modification and Waiver

Supplements and amendments to the Indentures or the Notes of any series may be made by the Company, the subsidiary guarantors and the applicable trustee with the consent (including, for the avoidance of doubt, consents obtained in connection with a tender offer or exchange offer for Notes or a solicitation of consents in respect of such Notes) of the holders of a majority in aggregate principal amount of the Notes of each series affected by such amendment or supplement, considered together as a single class; provided that no such modification or amendment may, without the consent of each holder affected thereby,

(1) reduce the percentage of principal amount of such Notes whose holders must consent to an amendment, supplement or waiver of any provision of the applicable Indenture or such Notes;

(2) reduce the rate or change the time for payment of interest, including default interest, if any, on such Notes of any series;

(3) reduce the principal amount of any such Note or change the Maturity Date of such Notes;

(4) reduce the amount payable upon redemption of any such Note;

(5) adversely affect the conversion rights of any such Note that is convertible in accordance with the applicable provisions of such Note;

(6) waive any Event of Default in the payment of principal of, any premium or interest on such Notes;

(7) make any such Note payable in money other than that stated in such Note;

(8) impair the right of holders of such Notes to receive payment of the principal of and interest on the Notes on the respective due dates therefor and to institute suit for the enforcement of any such payment; or

(9) make any change in the percentage of principal amount of such Notes necessary to waive compliance with certain provisions of the applicable Indenture.

The purposes for which the Company, the subsidiary guarantors and the applicable trustee may be able to supplement or amend any Indenture or the Notes issued thereunder without notice to or the consent of any holder of such Notes, as applicable, include:

(1) to cure any ambiguity, omission, defect or inconsistency;

(2) to comply with certain provisions of such Indenture;

(3) to add to, change or eliminate any of the provisions of such Indenture; provided that any such addition, change or elimination will not be effective as to Notes issued thereunder and outstanding prior to the date of such amendment or supplement;

(4) to establish the forms or terms of the Notes of any series issued under such Indenture;

(5) to evidence the acceptance or appointment of a separate trustee or successor trustee;

(6) in the case of any Notes issued under the 2010 or 2014 Indenture that are designated as Subordinated Debt Securities under such Indenture, to make any change in Article Eleven of such Indenture that would limit or terminate the benefits available to any holder of Senior Indebtedness under such Article Eleven;

(7) to reflect the addition or release of any subsidiary guarantor, as provided for by such Indenture, or to secure any of the Notes issued thereunder or the applicable Guarantees;

(8) to comply with any requirements of the SEC in order to effect or maintain the qualification of the applicable Indenture under the Trust Indenture Act;

(9) to provide for uncertificated Notes in addition to certificated Notes;

(10) to make provisions with respect to the conversion of Notes of any series that are convertible in accordance with the terms of such Notes; or

(11) to make any change that would provide any additional benefit or rights to the holders of such series or that does not adversely affect the rights of any holder of such series in any material respect.

The holders of a majority in aggregate principal amount of such outstanding Notes may waive any past default under the applicable Indenture, except a default in the payment of principal, or any premium or interest.

Each holder has the right to receive payment of the principal of and interest such holder's Notes at Maturity, or to institute suit for the enforcement of any such payment, and such right may not be impaired without the consent of such holder. Notwithstanding the foregoing and for the avoidance of doubt, no amendment to, or deletion or waiver of any of, the covenants set forth in the Indentures or any action taken by the Company or any subsidiary guarantor not prohibited by such Indenture (in each case other than with respect to actions described above that require the consent of each holder of an outstanding Note affected) will be deemed to impair or affect any rights of any holder to receive such payment.

Governing Law

The Indentures provide that they, the Notes issued thereunder and the Guarantees will be governed by, and construed in accordance with, the laws of the State of New York.

Information Concerning the Trustee

We may maintain banking and other commercial relationships with the trustees and their affiliates in the ordinary course of business, and the trustees may own our debt securities, including the Notes.

The trustees are permitted to become owners or pledgees of the Notes and may otherwise deal with the Company or its Subsidiaries or Affiliates with the same rights they would have if they were not trustees. If, however, a trustee acquires any conflicting interest (as defined in the Trust Indenture Act) after an Event of Default has occurred and is continuing, it must eliminate such conflict or resign.

In case an Event of Default occurs (and is continuing), the trustees will be required to use the degree of care and skill of a prudent person in the conduct of such person's own affairs. No trustee will be obligated to exercise any of its powers under the applicable Indenture at the request of any of the holders of the Notes issued thereunder, unless such holders have offered such trustee indemnity reasonably satisfactory to it.

Certain Definitions

"*Adjusted Consolidated Net Tangible Assets*" or "*ACNTA*" means, without duplication, as of the date of determination, (a) the sum of

(1) discounted future net revenue from proved oil and gas reserves of the Company and its Subsidiaries calculated in accordance with SEC guidelines before any state or federal income taxes, as estimated by petroleum engineers (which may include the Company's internal engineers) in a reserve report prepared as of the end of the Company's most recently completed fiscal year, as increased by, as of the date of determination, the discounted future net revenue of (A) estimated proved oil and gas reserves of the Company and its Subsidiaries attributable to any acquisition consummated since the date of such year-end reserve report and (B) estimated proved oil and gas reserves of the Company and its Subsidiaries attributable to extensions, discoveries and other additions and upward revisions of estimates of proved oil and gas reserves due to exploration, development or exploitation, production or other activities conducted or otherwise occurring since the date of such year-end reserve report which, in the case of sub-clauses (A) and (B), would, in accordance with standard industry practice, result in such increases as calculated in accordance with SEC guidelines (utilizing the prices utilized in such year-end reserve report), and decreased by, as of the date of determination, the discounted future net revenue of (C) estimated proved oil and gas reserves of the Company and its Subsidiaries produced or disposed of since the date of such year-end reserve report and (D) reductions in the estimated oil and gas reserves of the Company and its Subsidiaries since the date of such year-end reserve report attributable to downward revisions of estimates of proved oil and gas reserves due to exploration, development or exploitation, production or other activities conducted or otherwise occurring since the date of such year-end reserve report which, in the case of sub-clauses (C) and (D) would, in accordance with standard industry practice, result in such decreases as calculated in accordance with SEC

guidelines (utilizing the prices utilized in such year-end reserve report); provided that, in the case of each of the determinations made pursuant to clauses (A) through (D), such increases and decreases may be estimated by the Company's engineers,

(2) the capitalized costs that are attributable to oil and gas properties of the Company and its Subsidiaries to which no proved oil and gas reserves are attributable, based on the Company's books and records as of a date no earlier than the date of the Company's latest annual or quarterly financial statements,

(3) the Net Working Capital on a date no earlier than the date of the Company's latest annual or quarterly financial statements, and

(4) the greater of (A) the net book value on a date no earlier than the date of the Company's latest annual or quarterly financial statements and (B) the appraised value, as estimated by independent appraisers, of other tangible assets (including Investments in unconsolidated Subsidiaries) of the Company and its Subsidiaries, as of a date no earlier than the date of the Company's latest audited financial statements, minus (b) the sum of

a. minority interests,

b. any gas balancing liabilities of the Company and its Subsidiaries reflected as a long-term liability in the Company's latest annual or quarterly financial statement,

c. the discounted future net revenue, calculated in accordance with SEC guidelines (utilizing the prices utilized in the Company's year-end reserve report), attributable to reserves which are required to be delivered to third parties to fully satisfy the obligations of the Company and its Subsidiaries with respect to Volumetric Production Payments on the schedules specified with respect thereto,

d. the discounted future net revenue, calculated in accordance with SEC guidelines, attributable to reserves subject to Dollar-Denominated Production Payments which, based on the estimates of production included in determining the discounted future net revenue specified in (a)(1) above (utilizing the same prices utilized in the Company's year-end reserve report), would be necessary to fully satisfy the payment obligations of the Company and its Subsidiaries with respect to Dollar-Denominated Production Payments on the schedules specified with respect thereto, and

e. the discounted future net revenue, calculated in accordance with SEC guidelines (utilizing the same prices utilized in the Company's year-end or quarterly reserve report, as applicable), attributable to reserves subject to participation interests, overriding royalty interests or other interests of third parties, pursuant to participation, partnership, vendor financing or other agreements then in effect, or which otherwise are required to be delivered to third parties.

For the avoidance of doubt, "reserves" includes any reserves applicable to natural gas liquids.

"*Affiliate*" of any specified Person means any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For the purposes of this definition, "control" when used with respect to any specified Person means the power to direct the management and policies of such Person directly or indirectly, whether through the ownership of Voting Stock, by contract or otherwise; and the terms "controlling" and "controlled" have meanings correlative to the foregoing.

"*Attributable Indebtedness*" means, with respect to any particular lease under which any Person is at the time liable and at any date as of which the amount thereof is to be determined, the present value of the total net amount of rent required to be paid by such Person under the lease during the primary term thereof, without giving effect to any renewals at the option of the lessee, discounted from the respective due dates thereof to such date at the rate of interest per annum implicit in the terms of the lease. As used in the preceding sentence, the "net amount of rent" under any lease for any such period means the sum of rental and other payments required to be paid with respect to such period by the lessee thereunder excluding any amounts required to be paid by such lessee on account of maintenance and repairs, insurance, taxes, assessments, water rates or similar charges. In the case of any lease which is terminable by the lessee upon payment of a penalty, such net amount of rent will also include the amount of such penalty, but no rent will be considered as required to be paid under such lease subsequent to the first date upon which it may be so terminated.

"*Bankruptcy Law*" means Title 11, U.S. Code or any similar federal or state law for the relief of debtors.

"*Capital Stock*" means, with respect to any Person, any and all shares, interests, participations or other equivalents (however designated) of corporate stock, partnership or limited liability company interests or, in the case of the 2010 and 2014 Indentures, other equity securities (including, without limitation, beneficial interests in or other securities of a trust), and any and all warrants, options and rights with respect thereto (whether or not currently exercisable), including each class of common stock and preferred stock of such Person.

"*Credit Facilities*" means, one or more debt facilities (including, without limitation, the Company's existing credit facility) or commercial paper facilities, in each case with banks, investment banks, insurance companies, mutual funds and/or other institutional lenders providing for revolving credit loans, term loans, receivables financing (including through the sale of receivables to such lenders or to special purpose entities formed to borrow from (or sell receivables to) such lenders against such receivables) or letters of credit, in each case, as amended, extended, restated, renewed, refunded, replaced (under the 2010 and 2014 Indentures, whether contemporaneously or otherwise) or refinanced (in each case with Credit Facilities), supplemented or otherwise modified (in whole or in part and without limitation as to amount, terms, conditions, covenants and other provisions) from time to time.

"*Depositary*" means The Depository Trust Company or any successor Depositary registered as a clearing agency under the Exchange Act or other applicable statute or regulations.

"*Exchange Act*" means the Securities Exchange Act of 1934, as amended, and the rules and regulations of the SEC thereunder.

"*Guarantee*" means, individually and collectively, the guarantees given by the subsidiary guarantors pursuant to the Indentures.

"*Maturity Date*" means, with respect to a series of Notes, the fixed date specified under the applicable Indenture as to such series on which the principal of such Notes becomes due and payable.

"*Net Available Proceeds*" means, with respect to any Sale/Leaseback Transaction of any Person, cash proceeds received (including any cash proceeds received by way of deferred payment of principal pursuant to a note or installment receivable or otherwise, but only as and when received, and excluding any other consideration until such time as such consideration is converted into cash) therefrom, in each case net of all legal, title and recording tax expenses, commissions and other fees and expenses incurred, and all federal, state or local taxes required to be accrued as a liability as a consequence of such Sale/Leaseback Transaction, and in each case net of all Indebtedness which is secured by such assets, in accordance with the terms of any Lien upon or with respect to such assets, or which must, by its terms or in order to obtain a necessary consent to such Sale/Leaseback Transaction or by applicable law, be repaid out of the proceeds from such Sale/Leaseback Transaction and which is actually so repaid.

"*Oil and Gas Business*" means the business of the exploration for, and exploitation, development, production, processing, marketing, storage and transportation of, hydrocarbons, and other related energy and natural resource businesses (including oil and gas services businesses related to the foregoing).

"*Paying Agent*" meant an office or agency where securities of a series may be presented for redemption or repurchase, if applicable, and for payment.

"*Person*" means any individual, corporation, partnership, limited liability company, joint venture, trust, estate, association, unincorporated organization or government or any agency or political subdivision thereof.

"*Senior Indebtedness*" means certain indebtedness of the Company or a subsidiary guarantor, unless such indebtedness is contractually subordinate or junior in right of payment of principal of, and any premium and interest on, the Notes of any series or the Guarantees, respectively.

"*Trust Indenture Act*" means the Trust Indenture Act of 1939 (15 U.S. Code Sections 77aaa-77bbbb).

"*U.S. Government Securities*" means securities that are (1) direct obligations of the United States of America for the payment of which its full faith and credit is pledged or (2) obligations of a Person controlled or supervised by and acting as an agency or instrumentality of the United States of America the payment of which is unconditionally guaranteed as a full faith and credit obligation by the United States of America, which, in either case under clauses (1) or (2) are not callable or redeemable at the option of the issuer thereof.

"*U.S. Legal Tender*" means such coin or currency of the United States as at the time of payment is legal tender for the payment of public and private debts.

"*Volumetric Production Payments*" means sales of limited-term overriding royalty interests in natural gas and oil reserves that (i) entitle the purchaser to receive scheduled production volumes over a period of time from specific lease interests; (ii) are free and clear of all associated future production costs and capital expenditures; (iii) are nonrecourse to the seller (i.e., the purchaser's only recourse is to the reserves acquired); (iv) transfer title of the reserves to the purchaser; and (v) allow the seller to retain all production beyond the specified volumes, if any, after the scheduled production volumes have been delivered.

"*Voting Stock*" means, with respect to any Person, securities of any class or classes of Capital Stock in such Person entitling the holders thereof (whether at all times or only so long as no senior class of stock has voting power by reason of contingency) to vote in the election of members of the board of directors of such Person.

Certain Definitions under the 2010 and 2014 Indentures

"*Funded Debt*" means, with regard to any Person, certain indebtedness incurred, created, assumed or guaranteed by such Person, which matures, or is renewable by such Person to a date, more than one year after the date as of which Funded Debt is being determined.

"*Lien*" means, with respect to any Person, any mortgage, pledge, lien, encumbrance, easement, restriction, charge or adverse claim affecting title or resulting in an encumbrance against real or personal property of such Person, or a security interest of any kind (including any conditional sale or other title retention agreement, any lease in the nature thereof or other similar agreement to sell, in each case securing obligations of such Person).

"*Maturity*" means, with respect to any Security, the date on which the principal of such Security or an installment of principal becomes due and payable as therein or herein provided, whether at the Maturity Date or by declaration of acceleration, call for redemption or otherwise.

"*Permitted Liens*" means

(i) with respect to a series of Notes, Liens existing on the issue date of such series of Notes;

(ii) Liens securing certain indebtedness under Credit Facilities;

(iii) Liens securing any renewal, extension, substitution, refinancing or replacement of secured certain indebtedness; provided, that such Liens extend to or cover only the property or assets then securing the certain indebtedness being refinanced and that the certain indebtedness being refinanced was not incurred under the Credit Facilities;

(iv) Liens on, or related to, properties to secure all or part of the costs incurred in the ordinary course of business of exploration, drilling, development or operation thereof;

(v) Liens upon (a) any property of or any interests in any Person existing at the time of acquisition of such property or interests by the Company or a Subsidiary, (b) any property of or interests in a Person existing at the time such Person is merged or consolidated with the Company or any Subsidiary or existing at the time of the sale or transfer of any such property of or interests in such Person to the Company or any Subsidiary, or (c) any property of or interests in a Person existing at the time such Person becomes a Subsidiary; provided, that in each case such Lien has not been created in contemplation of such sale, merger, consolidation, transfer or acquisition, and provided, further, that in each such case no such Lien will extend to or cover any property of the Company or any Subsidiary other than the property being acquired and improvements thereon;

(vi) Liens on deposits to secure public or statutory obligations or in lieu of surety or appeal bonds entered into in the ordinary course of business;

(vii) Liens in favor of collecting or payor banks having a right of setoff, revocation, refund or chargeback with respect to money or instruments of the Company or any Subsidiary on deposit with or in possession of such bank;

(viii) purchase money security interests granted in connection with the acquisition of assets in the ordinary course of business and consistent with past practices, provided, that (a) such Liens attach only to the property so acquired with the purchase money indebtedness secured thereby and (b) such Liens secure only certain indebtedness that is not in excess of 100% of the purchase price of such assets;

(ix) Liens reserved in oil and gas mineral leases for bonus or rental payments and for compliance with the terms of such leases;

(x) Liens arising under partnership agreements, oil and gas leases, farm-out agreements, division orders, contracts for the sale, purchase, exchange, transportation or processing of oil, gas or other hydrocarbons, unitization and pooling declarations and agreements, development agreements, operating agreements, area of mutual interest agreements, and other similar agreements which are customary in the Oil and Gas Business;

(xi) Liens securing obligations of the Company or any of its Subsidiaries under Oil and Gas Hedging Contracts;

(xii) Liens in favor of the United States, any State thereof, any foreign country or any department, agency or instrumentality or political subdivision of any such jurisdiction, to secure partial, progress, advance or other payments pursuant to any contract or statute or to secure any indebtedness incurred for the purpose of financing all or any part of the purchase price or the cost of constructing or improving the property subject to such Liens, including without limitation, Liens to secure Funded Debt of the pollution control or industrial revenue bond type; and

(xiii) Liens in favor of the Company or any subsidiary guarantor.

“*Principal Property*” means any property interest in oil and gas reserves located in the United States owned by the Company or any Subsidiary and which is capable of producing crude oil, condensate, natural gas, natural gas liquids or other similar hydrocarbon substances in paying quantities, the net book value of which property interest or interests exceeds two (2) percent of Adjusted Consolidated Net Tangible Assets, except any such property interest or interests that in the opinion of the board of directors of the Company is not of material importance to the total business conducted by the Company and its Subsidiaries taken as a whole. Without limitation, the term “Principal Property” shall not include:

(i) property or assets employed in gathering, treating, processing, refining, transportation, distribution or marketing,

(ii) accounts receivable and other obligations of any obligor under a contract for the sale, exploration, production, drilling, development, processing or transportation of crude oil, condensate, natural gas, natural gas liquids or other similar hydrocarbon substances by the Company or any of its Subsidiaries, and all related rights of the Company or any of its Subsidiaries, and all guarantees, insurance, letters of credit and other agreements or arrangements of whatever character supporting or securing payment of such receivables or obligations, or

(iii) the production or any proceeds from production of crude oil, condensate, natural gas, natural gas liquids or other similar hydrocarbon substances.

“*Restricted Subsidiary*” means any Subsidiary that, as of the applicable date of determination, (i) is a subsidiary guarantor or (ii) directly owns or leases any Principal Property.

“*Sale/Leaseback Transaction*” means with respect to the Company or any Restricted Subsidiary, any arrangement with any Person providing for the leasing by the Company or any of its Restricted Subsidiaries of any Principal Property which was acquired or placed into service more than one year prior to such arrangement, whereby such property has been or is to be sold or transferred by the Company or such Restricted Subsidiary to such Person; provided, that the term “Sale/Leaseback Transaction” does not include any such arrangement that does not provide for a lease by the Company or any of its Restricted Subsidiaries with a period, including renewals, of more than three years.

Certain Definitions under the 2005 Indenture

“*Indebtedness*” means, without duplication, with respect to any Person,

(a) all obligations of such Person

- (i) in respect of borrowed money (whether or not the recourse of the lender is to the whole of the assets of such Person or only to a portion thereof),
- (ii) evidenced by bonds, notes, debentures or similar instruments,
- (iii) representing the balance deferred and unpaid of the purchase price of any property or services (other than accounts payable or other obligations arising in the ordinary course of business),
- (iv) evidenced by bankers’ acceptances or similar instruments issued or accepted by banks,
- (v) for the payment of money relating to a Capitalized Lease Obligation, or
- (vi) evidenced by a letter of credit or a reimbursement obligation of such Person with respect to any letter of credit;

(b) all net obligations of such Person under Interest Rate Hedging Agreements, Oil and Gas Hedging Contracts and Currency Hedge Obligations, except to the extent such net obligations are taken into account in the determination of future net revenues from proved oil and gas reserves for purposes of the calculation of Adjusted Consolidated Net Tangible Assets;

(c) all liabilities of others of the kind described in the preceding clauses (a) or (b) that such Person has guaranteed or that are otherwise its legal liability (including, with respect to any Production Payment, any warranties or guaranties of production or payment by such Person with respect to such Production Payment but excluding other contractual obligations of such Person with respect to such Production Payment);

(d) Indebtedness (as otherwise defined in this definition) of another Person secured by a Lien on any asset of such Person, whether or not such Indebtedness is assumed by such Person, the amount of such obligations being deemed to be the lesser of (1) the full amount of such obligations so secured, and (2) the fair market value of such asset, as determined in good faith by the board of directors of such Person, which determination shall be evidenced by a Board Resolution,

(e) with respect to such Person, the liquidation preference or any mandatory redemption payment obligations in respect of Disqualified Stock;

(f) the aggregate preference in respect of amounts payable on the issued and outstanding shares of preferred stock of any of such Person's Subsidiaries in the event of any voluntary or involuntary liquidation, dissolution or winding up (excluding any such preference attributable to such shares of preferred stock that are owned by such Person or any of its Subsidiaries; provided, that if such Person is the Company, such exclusion shall be for such preference attributable to such shares of preferred stock that are owned by the Company or any of its Subsidiaries); and

(g) any and all deferrals, renewals, extensions, refinancings and refundings (whether direct or indirect) of, or amendments, modifications or supplements to, any liability of the kind described in any of the preceding clauses (a), (b), (c), (d), (e), (f) or this clause (g), whether or not between or among the same parties. Subject to clause (c) of the preceding sentence, neither Dollar-Denominated Production Payments nor Volumetric Production Payments shall be deemed to be Indebtedness.

"*Permitted Liens*" means:

(i) Liens existing on the issue date;

(ii) Liens securing Indebtedness under Credit Facilities;

(iii) Liens now or hereafter securing any Interest Rate Hedging Agreements so long as the related Indebtedness (a) constitutes the Existing Notes or the Securities (or any Permitted Company Refinancing Indebtedness in respect thereof) or (b) is, or is permitted to be under the 2005 Indenture, secured by a Lien on the same property securing such interest rate hedging obligations;

(iv) Liens securing Permitted Company Refinancing Indebtedness or Permitted Subsidiary Refinancing Indebtedness; provided, that such Liens extend to or cover only the property or assets currently securing the Indebtedness being refinanced and that the Indebtedness being refinanced was not incurred under the Credit Facilities;

(v) Liens for taxes, assessments and governmental charges not yet delinquent or being contested in good faith and for which adequate reserves have been established to the extent required by GAAP;

(vi) mechanics’, worker’s, materialmen’s, operators’ or similar Liens arising in the ordinary course of business;

(vii) Liens in connection with worker’s compensation, unemployment insurance or other social security, old age pension or public liability obligations;

(viii) Liens, deposits or pledges to secure the performance of bids, tenders, contracts (other than contracts for the payment of money), leases, public or statutory obligations, surety, stay, appeal, indemnity, performance or other similar bonds, or other similar obligations arising in the ordinary course of business;

(ix) survey exceptions, encumbrances, easements or reservations of, or rights of others for, rights of way, zoning or other restrictions as to the use of real properties, and minor defects in title which, in the case of any of the foregoing, were not incurred or created to secure the payment of borrowed money or the deferred purchase price of property or services, and in the aggregate do not materially adversely affect the value of such properties or materially impair use for the purposes of which such properties are held by the Company or any Subsidiaries;

(x) Liens on, or related to, properties to secure all or part of the costs incurred in the ordinary course of business of exploration, drilling, development or operation thereof;

(xi) Liens on pipeline or pipeline facilities which arise out of operation of law;

(xii) judgment and attachment Liens not giving rise to an Event of Default or Liens created by or existing from any litigation or legal proceeding that are currently being contested in good faith by appropriate proceedings and for which adequate reserves have been made;

(xiii) (a) Liens upon any property of any Person existing at the time of acquisition thereof by the Company or a Subsidiary, (b) Liens upon any property of a Person existing at the time such Person is merged or consolidated with the Company or any Subsidiary or existing at the time of the sale or transfer of any such property of such Person to the Company or any Subsidiary, or (c) Liens upon any property of a Person existing at the time such Person becomes a Subsidiary; provided, that in each case such Lien has not been created in contemplation of such sale, merger, consolidation, transfer or acquisition, and provided, further, that in each such case no such Lien shall extend to or cover any property of the Company or any Subsidiary other than the property being acquired and improvements thereon;

(xiv) Liens on deposits to secure public or statutory obligations or in lieu of surety or appeal bonds entered into in the ordinary course of business;

(xv) Liens in favor of collecting or payor banks having a right of setoff, revocation, refund or chargeback with respect to money or instruments of the Company or any Subsidiary on deposit with or in possession of such bank;

(xvi) purchase money security interests granted in connection with the acquisition of assets in the ordinary course of business and consistent with past practices, provided, that (A) such Liens attach only to the property so acquired with the purchase money indebtedness secured thereby and (B) such Liens secure only Indebtedness that is not in excess of 100% of the purchase price of such assets;

(xvii) Liens reserved in oil and gas mineral leases for bonus or rental payments and for compliance with the terms of such leases;

(xviii) Liens arising under partnership agreements, oil and gas leases, farm-out agreements, division orders, contracts for the sale, purchase, exchange, transportation or processing (but not refining) of oil, gas or other hydrocarbons, unitization and pooling declarations and agreements, development agreements, operating agreements, area of mutual interest agreements, and other similar agreements which are customary in the Oil and Gas Business;

(xix) Liens securing obligations of the Company or any of its Subsidiaries under Currency Hedge Obligations or Oil and Gas Hedging Contracts;

(xx) Liens to secure Dollar-Denominated Production Payments and Volumetric Production Payments; and

(xxi) Liens securing other Indebtedness in an aggregate principal amount which, together with all other Indebtedness outstanding on the date of such incurrence and secured by Liens pursuant to this clause (xxi), does not exceed 15% of Adjusted Consolidated Tangible Net Assets.

"*Sale/Leaseback Transaction*" means with respect to the Company or any of its Subsidiaries, any arrangement with any Person providing for the leasing by the Company or any of its Subsidiaries of any principal property, acquired or placed into service more than 180 days prior to such arrangement, whereby such property has been or is to be sold or transferred by the Company or any of its Subsidiaries to such Person.

Exhibit 21

CHESAPEAKE ENERGY CORPORATION

an Oklahoma Corporation

SIGNIFICANT SUBSIDIARIES*

Limited Liability Companies	State of Organization
Brazos Valley Longhorn, L.L.C.	Delaware
Chesapeake Appalachia, L.L.C.	Oklahoma
Chesapeake Energy Louisiana, LLC	Oklahoma
Chesapeake Exploration, L.L.C.	Oklahoma
Chesapeake Land Development Company, L.L.C.	Oklahoma
Chesapeake Operating, L.L.C.	Oklahoma
WHR Eagle Ford LLC	Delaware

Partnerships	State of Organization
Chesapeake Louisiana, L.P.	Oklahoma

* In accordance with Regulation S-K Item 601(b)(21), the names of particular subsidiaries that, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary (as that term is defined in Rule 1-02(w) of Regulation S-X) as of the end of the year covered by this report have been omitted.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 333-126191, 333-135949, 333-143990, 333-151762, 333-160350, 333-171468, 333-178067, 333-187018, 333-189651, 333-192175, 333-196977 and 333-216483) and Form S-3 (File No. 333-219649) of Chesapeake Energy Corporation of our report dated February 27, 2020 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 27, 2020

Exhibit 23.2

Software Integrated Solutions
Division of Schlumberger Technology Corporation

4600 J Barry Court
Suite 200
Canonsburg, PA 15317 USA
Tel: +724-416-9700
Fax: +724-416-9705

CONSENT OF SOFTWARE INTEGRATED SOLUTIONS DIVISION OF SCHLUMBERGER TECHNOLOGY CORPORATION

As independent oil and gas consultants, Software Integrated Solutions, Division of Schlumberger Technology Corporation hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 333-126191, 333-135949, 333-143990, 333-151762, 333-160350, 333-171468, 333-178067, 333-187018, 333-189651, 333-192175, 333-196977 and 333-216483) and Form S-3 (File No. 333-219649) of Chesapeake Energy Corporation of all references to our firm and information from our reserves report dated 4 February 2020, included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K for the year ended 31 December 2019 to be filed with the Securities and Exchange Commission on or about 27 February 2020, and our summary report attached as Exhibit 99.1 to such Annual Report.

Software Integrated Solutions
Division of Schlumberger Technology Corporation

By: /s/ Charles M. Boyer II
Charles M. Boyer II, PG, CPG
Advisor - Unconventional Reservoirs
Technical Team Leader

Canonsburg, Pennsylvania
27 February, 2020

Exhibit 31.1

CERTIFICATION

I, Robert D. Lawler, certify that:

1. I have reviewed this Annual Report on Form 10-K of Chesapeake Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 27, 2020

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

Exhibit 31.2

CERTIFICATION

I, Domenic J. Dell’Osso, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K of Chesapeake Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 27, 2020

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

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Chesapeake Energy Corporation (the “Company”) on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert D. Lawler, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 27, 2020

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

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Chesapeake Energy Corporation (the “Company”) on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Domenic J. Dell’Osso, Jr., Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 27, 2020

By: /s/ DOMENIC J. DELL'OSSO, JR.

Domenic J. Dell'Osso, Jr.

Executive Vice President and Chief Financial Officer

Exhibit 95.1

Mine Safety Disclosures

Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") and Item 104 of Regulation S-K (17 CFR 229.104) require certain disclosures by companies required to file periodic reports under the Securities Exchange Act of 1934, as amended, that operate mines regulated under the Federal Mine Safety and Health Act of 1977 (as amended by the Mine Improvement and New Emergency Response Act of 2006, the "Mine Act").

Burleson Sand LLC ("Burleson Sand") is a wholly owned subsidiary of Brazos Valley Longhorn, L.L.C. (successor in interest to WildHorse Resource Development Corporation) ("WildHorse"), which is a wholly owned subsidiary of Chesapeake Energy Corporation. On January 4, 2018, Burleson Sand acquired surface and sand rights on approximately 727 acres in Burleson County, Texas to construct and operate an in-field sand mine to support WildHorse's exploration and development operations. Burleson Sand began operations in September 2018 and is subject to regulation by the federal Mine Safety and Health Administration ("MSHA") under the Mine Act. The MSHA inspects mining facilities on a regular basis and issues citations and orders when it believes a violation has occurred under the Mine Act.

The MSHA, upon determination that a violation of the Mine Act has occurred, may issue a citation or an order which generally proposes civil penalties or fines upon the mine operator. Citations and orders may be appealed with the potential of reduced or dismissed penalties.

During the three-month period ended December 31, 2019, Burleson Sand did not receive any of the following from MSHA: (i) a citation for a violation of a mandatory health or safety standard that could significantly and substantially contribute to the cause and effect of a mine safety or health hazard under Section 104 of the Mine Act; (ii) an order issued under Section 104(b) of the Mine Act; (iii) a citation or order for unwarrantable failure to comply with mandatory health or safety standards under Section 104(d) of the Mine Act; (iv) written notice of a flagrant violation under Section 110(b)(2) of the Mine Act; (v) an imminent danger order issued under Section 107(a) of the Mine Act; (vi) any proposed assessments under the Mine Act; (vii) written notice of a pattern of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of mine health or safety hazards under Section 104(e) of the Mine Act; or (viii) written notice of the potential to have such a pattern. Moreover, during the three-month period ended December 31, 2019, Burleson Sand did not experience a mining-related fatality or have any pending legal action before the Federal Mine Safety and Health Review Commission.

Software Integrated Solutions
Division of Schlumberger Technology Corporation

4600 J. Barry Court
Suite 200
Canonsburg, Pennsylvania 15317 USA
Tel: +1-724-416-9700
Fax: +1-724-416-9705

Exhibit 99.1

4 February 2020

Chesapeake Energy Corporation
6100 N. Western Avenue
Oklahoma City, OK 73118

Dear Gentlemen:

At the request of Chesapeake Energy Corporation (Chesapeake), through their letter of engagement, Software Integrated Solutions (SIS) Division of Schlumberger Technology Corporation has evaluated the proved reserves of certain Chesapeake oil and gas interests located in the United States (U.S.) as of 31 December 2019. The evaluated properties are located in Louisiana, Oklahoma, Pennsylvania, Texas, and Wyoming. This report was completed as of the date of this letter and has been prepared using constant prices and costs and conforms to our understanding of the U.S. Securities and Exchange Commission (SEC) guidelines and applicable financial accounting rules. All prices, costs, and cash flow estimates are expressed in U.S. dollars (US$). It is our understanding that the total proved properties evaluated by SIS comprise 81.0% of Chesapeake's reserves and 84.9% of the Discounted Present Value @10%. We prepared this report for Chesapeake's use in filing with the SEC. We believe that the assumptions, data, methods, and procedures used in preparing this report are appropriate for the purpose of this report and that we have used all methods and procedures that we consider necessary and appropriate under the circumstances to prepare this report. The Lead Evaluator for this evaluation was Charles M. Boyer II, PG, CPG, and his qualifications, independence, objectivity, and confidentiality meet the requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The results of the Proved reserve evaluation are summarized in **Table 1** and **Table 2**. The values contained in this report do not include existing Chesapeake financial instruments or hedges.

Table 1
Estimated Net Reserves And Income
Certain Oil And Gas Interests
Chesapeake Energy Corporation
As Of 31 December 2019
Proved Developed And Undeveloped Reserves

	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Remaining Net Reserves			
Oil – Mbbls	146,834.41	119,126.48	265,960.89
NGL – Mbbls	57,711.56	23,589.66	81,301.21
Gas – MMscf	2,748,500.69	2,814,084.61	5,562,585.29
Oil Equiv. – Mbbls	662,629.41	611,730.24	1,274,359.65
Income Data (M$)			
Future Net Revenue	12,309,379.32	11,396,730.92	23,706,110.24
Deductions			
Operating Expense	2,395,252.39	1,034,215.53	3,429,467.92
Production Taxes	771,737.40	570,950.89	1,342,688.28
Abandonment Expense	232,332.35	58,416.22	290,748.57
Investment	7,258.18	3,972,430.49	3,979,688.66
Future Net Cashflow (FNC)	8,902,798.97	5,760,717.78	14,663,516.75
Discounted PV @ 10% (M$)	5,281,433.95	2,374,831.18	7,656,265.12

Table 2
Estimated Net Reserves And Income
Certain Oil And Gas Interests
Summarized By Reserve Category
Chesapeake Energy Corporation
As Of 31 December 2019

	Proved Producing Reserves	Proved NonProducing Reserves	Proved Shut-In Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Remaining Net Reserves					
Oil – Mbbls	146,597.73	236.68	0.00	119,126.48	265,960.89
NGL – Mbbls	57,654.10	57.46	0.00	23,589.66	81,301.21
Gas – MMscf	2,726,246.78	22,253.91	0.00	2,814,084.61	5,562,585.29
Oil Equiv. – Mbbls	658,626.29	4,003.12	0.00	611,730.24	1,274,359.65
Income Data (M$)					
Future Net Revenue	12,262,764.28	46,615.03	0.01	11,396,730.92	23,706,110.24
Deductions					
Operating Expense	2,387,026.03	8,054.19	172.17	1,034,215.53	3,429,467.92
Production Taxes	769,618.96	2,118.43	0.00	570,950.89	1,342,688.28
Abandonment Expense	222,097.84	1,235.87	8,998.64	58,416.22	290,748.57
Investment	0.00	7,258.18	0.00	3,972,430.49	3,979,688.66
Future Net Cashflow (FNC)	8,884,021.41	27,948.37	-9,170.80	5,760,717.78	14,663,516.75
Discounted PV @ 10% (M$)	5,270,033.17	15,014.18	-3,613.40	2,374,831.18	7,656,265.12

The values in the tables above may not add up arithmetically due to rounding procedures in the computer software program used to prepare the economic projections. All hydrocarbon liquids are reported as 42 gallon barrels. Gas volumes are reported at the standard pressure and temperature bases of the area where the gas is sold.

We are independent with respect to Chesapeake as provided in the SEC regulations. Neither the employment of nor the compensation received by SIS was contingent upon the values estimated for the properties included in this report.

Oil and gas reserves by definition fall into one of the following categories: proved, probable, and possible. The proved category is further divided into: developed and undeveloped. The developed reserve category is even further divided into the appropriate reserve status subcategories: producing and non-producing. Non-producing reserves include shut-in and behind-pipe reserves. The reserves included in this report include only proved reserves and do not include probable or possible reserves. Chesapeake has an active exploration and development program to develop their interests in certain tracts not classified as proved at this time. Future drilling may result in the reclassification of additional volumes to the proved reserve category. However, changes in the regulatory requirements for oil and gas operations may impact future development plans and the ability of the company to recover the estimated proved undeveloped reserves. The reserves and income attributable to the various reserve categories included in this report have not been adjusted to reflect the varying degrees of risk associated with them.

Reserve estimates are strictly technical judgments. The accuracy of any reserve estimate is a function of the quality and quantity of data available and of the engineering and geological interpretations. The reserve estimates presented in this report are believed reasonable; however, they are estimates only and should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify their revision. A portion of these reserves are for producing or non-producing wells that lack sufficient production history to utilize conventional performance-based reserve estimates. In these cases, the reserves are based on volumetric estimates and recovery efficiencies along with analogies to similar producing areas. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. As additional production and pressure data becomes available, these estimates may be revised up or down. Actual future prices may vary significantly from the prices used in this evaluation; therefore, future hydrocarbon volumes recovered and the income received from these volumes may vary significantly from those estimated in this report. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

Standard geological and engineering methods generally accepted by the petroleum industry were used in the estimation of Chesapeake's reserves. Deterministic methods were used for all reserves included in this report. The appropriate combination of conventional decline curve analysis (DCA), production data analysis, volumetrics, reservoir simulation, and type curves were used to estimate the remaining reserves in the various producing areas. Volumetric calculations were based on data and maps provided by Chesapeake. Comparisons were made to similar properties for which more complete data were available for areas of new development.

All prices used in preparation of this report were based on the twelve month unweighted arithmetic average of the first day of the month price for the period January through December 2019. The resulting Henry Hub reference gas price used was $2.58/MMBtu and the resulting West Texas Intermediate reference oil price used was $55.69/Bbl. Henry Hub gas price and West Texas Intermediate oil price are common reference prices for natural gas and oil production in the U.S. The prices were adjusted for local differentials, gravity and Btu where applicable. As required by SEC guidelines, all pricing was held constant for the life of the projects (no escalation). **Table 3** summarizes the 2019 reference prices and the resulting average prices used in this reserves evaluation. The average prices were calculated using the total future revenue by product prior to taxes and expenses divided by the total net reserves by product.

Table 3
Chesapeake Energy Corporation
Oil, Gas And NGL Prices
Year End 2019 Reserves Evaluation

Product	Reference Point	Year End 2019 Reference Price	Average Price
Oil	West Texas Intermediate	$55.69/Bbl	$56.53/Bbl
NGL	West Texas Intermediate	$55.69/Bbl	$10.26/Bbl
Natural Gas	Henry Hub	$2.58/MMBtu	$1.41/Mscf

Operating costs used in this report were based on values reported by Chesapeake and reviewed by SIS. Operating cost assumptions were based on the prior twelve months average data. Chesapeake's estimates for capital costs for all non-producing and undeveloped wells are included in the evaluation. Abandonment and salvage were included as expenses 120 months after the economic limit is reached. Chesapeake has indicated to us that they have the ability and intent to implement their capital expenditure program as scheduled. Operating costs and capital costs were held constant for the life of the projects (no escalation).

Net revenue (sales) is defined as the total proceeds from the sale of oil, condensate, natural gas liquids (NGL), and gas adjusted for commodity price basis differential and gathering/ transportation expense. Future net income (cashflow) is future net revenue less net lease operating expenses, state severance or production taxes, certain allowed corporate general administrative and overhead costs, operating/development capital expenses and net salvage. Future plugging, abandonment, and salvage costs are included after the economic life of each well or unit. No provisions for State or Federal income taxes have been made in this evaluation. The present worth (discounted cashflow) at various discount rates is calculated on a monthly basis.

In the conduct of our evaluation, we have not independently verified the accuracy and completeness of information and data furnished by Chesapeake with respect to ownership interests, historical oil and gas production, costs of operation and development, product prices, payout balances, and agreements relating to current and future operations and sales of production. If in the course of our examination something came to our attention which brought into question the validity or sufficiency of any of the information or data provided by Chesapeake, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

In our opinion the above-described estimates of Chesapeake's proved reserves and supporting data are, in the aggregate, reasonable. It is also our opinion that the above-described estimates of Chesapeake's proved reserves conform to the definitions of proved oil and gas reserves promulgated by the Securities and Exchange Commission. These reserves definitions are provided at the conclusion of this letter.

All data used in this study were obtained from Chesapeake, public industry information sources, or the non-confidential files of SIS. A field inspection of the properties was not made in connection with the preparation of this report. The potential environmental liabilities attendant to ownership and/or operation of the properties have not been addressed in this report. Abandonment and clean-up costs and possible salvage value of the equipment were considered in this report.

In evaluating the information at our disposal related to this report, we have excluded from our consideration all matters which require a legal or accounting interpretation, or any interpretation other than those of an engineering or geological nature. In assessing the conclusions expressed in this report pertaining to all aspects of oil and gas evaluations, especially pertaining to reserve evaluations, there are uncertainties inherent in the interpretation of engineering data, and such conclusions represent only informed professional judgments.

Data and worksheets used in the preparation of this evaluation will be maintained in our files in Canonsburg and will be available for inspection by anyone having proper authorization from Chesapeake.

Sincerely yours,

/s/ Denise L. Delozier

Denise L. Delozier
Principal Reservoir Engineer

/s/ Charles M. Boyer II

Charles M. Boyer II, PG, CPG
Advisor - Unconventional Reservoirs
Technical Team Leader

SECURITIES AND EXCHANGE COMMISION
REGULATION S-X, RULE 210.4-10 (a)

RESERVES DEFINITIONS

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an “analogous reservoir” refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or *G&G* costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is 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 gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms *structural feature* and *stratigraphic condition* are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.* (i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (“oil and gas”) in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(*1*) Lifting the oil and gas to the surface; and

(*2*) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a “terminal point”, which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.* (i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

NOTE TO PARAGRAPH (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (*i.e.*, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (*i.e.*, potentially recoverable resources from undiscovered accumulations).

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as “exploratory type” if not drilled in a known area or “development type” if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.