# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 8-K

**CURRENT REPORT**
**Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

**Date of Report (Date of earliest event reported): February 2, 2021**

# CHESAPEAKE ENERGY CORPORATION

(Exact name of Registrant as specified in its Charter)

| **Oklahoma** | **1-13726** | **73-1395733** |
|---|---|---|
| (State or other jurisdiction of incorporation) | (Commission File No.) | (IRS Employer Identification No.) |
| **6100 North Western Avenue** | **Oklahoma City OK** | **73118** |
| (Address of principal executive offices) | | (Zip Code) |

**(405) 848-8000**
(Registrant's telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Securities registered pursuant to Section 12(b) of the Act: None.

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§ 230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§ 240.12b-2 of this chapter).

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. ☐

**Item 8.01 Other Events.**

As previously disclosed on June 28, 2020, Chesapeake Energy Corporation ("Chesapeake") and certain of its subsidiaries (together with Chesapeake, the "Company") filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code (the "Chapter 11 Cases") in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). The Company's Chapter 11 Cases were jointly administered under the caption *In re Chesapeake Energy Corporation, et al.*, No. 20-33233 (DRJ).

As previously disclosed, on January 16, 2021, the Bankruptcy Court entered an order (the "Confirmation Order") confirming the Fifth Amended Joint Chapter 11 Plan of Reorganization of Chesapeake Energy Corporation and Its Debtor Affiliates (the "Plan"). The Debtors expect that the effective date of the Plan will occur once all conditions precedent to the Plan have been satisfied (defined in the Plan as the "Effective Date").

We have recast certain information in this filing to reflect the retrospective application of our reverse stock split effective April 14, 2020 and for information regarding our Chapter 11 Cases for all periods presented in the following sections of our Annual Report on Form 10-K for the year ended December 31, 2019 (the "Previously Filed Annual Report") as follows:

- Part II, Item 6. Selected Financial Data,
- Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations,
- Part II, Item 8. Financial Statements and Supplementary Data, and
- Part II, Item 9A. Controls and Procedures.

As this Current Report on Form 8-K is being filed only for the purpose described above, and only affects the Items specified above, the other information in the Previously Filed Annual Report filed with the Securities Exchange Commission (the "SEC") on February 27, 2020, as well as the Form 10-K/A filed with the SEC on April 29, 2020, remains unchanged. No attempt has been made in this Current Report on Form 8-K to modify or update disclosures in the Previously Filed Annual Report, except for the revision of certain financial information as described above. This Current Report on Form 8-K does not reflect events occurring after the filing of the Previously Filed Annual Report. Accordingly, this Current Report on Form 8-K should be read in conjunction with the Previously Filed Annual Report and the Company's filings made with the SEC subsequent to the filing of the Previously Filed Annual Report, including any amendments to those filings.

**Item 9.01 Financial Statements and Exhibits.**

(d) Exhibits

| **Exhibit No.** | **Document Description** |
|---|---|
| 23.1 | Consent of PricewaterhouseCoopers LLP. |
| 99.1 | Selected Financial Data, Management's Discussion and Analysis of Financial Condition and Results of Operations and Financial Statements and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2019. |
| 104 | Cover Page Interactive Data File (embedded within the Inline XBRL document and contained in Exhibit 101). |

## SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

**CHESAPEAKE ENERGY CORPORATION**

By: /s/ JAMES R. WEBB

James R. Webb

Executive Vice President — General Counsel and Corporate Secretary

Date: February 2, 2021

**Exhibit 23.1**

## 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) of Chesapeake Energy Corporation of our report dated February 27, 2020, except with respect to the matter that raises substantial doubt about the Company's ability to continue as a going concern and the effects of the reverse stock split discussed in Note 26, as to which the date is February 2, 2021, relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in this Current Report on Form 8-K.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 2, 2021

Exhibit 99.1

PART II

**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[(b)] | $ (49.97) | $ 29.26 | $ (139.32) | $ (1,051.83) | $ (3,436.90) |
| Diluted[(b)] | $ (49.97) | $ 29.26 | $ (139.32) | $ (1,051.83) | $ (3,436.90) |
| **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.

(b) All per share information has been retroactively adjusted to reflect a 1-for-200 (1:200) reverse stock split effective April 14, 2020. See Note 26 of the notes to our consolidated financial statements included in Item 8 of this report for additional information.

## 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.

**Recent Developments**

*Reverse Stock Split*

On April 13, 2020, our Board of Directors and our shareholders approved a 1-for-200 (1:200) reverse stock split of our common stock and a reduction of the total number of authorized shares of our common stock as determined by a formula based on two-thirds of the reverse stock split ratio ("Reverse Stock Split"). The reverse stock split became effective as of the close of business on April 14, 2020. Our common stock began trading on a split-adjusted basis on the NYSE at the market open on April 15, 2020. The par value of the common stock was not adjusted as a result of the reverse stock split.

The reverse stock split was intended to, among other things, increase the per share trading price of our common shares to satisfy the $1.00 minimum closing price requirement for continued listing on the NYSE. The price condition will be deemed cured if on the last trading day of any calendar month within six months following the receipt from the NYSE of the notice of non-compliance, we have a closing share price of at least $1.00 and an average closing share price of at least $1.00 over the 30 trading-day period ending on the last trading day of that month. On April 1, 2020, the NYSE tolled the compliance period through June 30, 2020. As a result of the reverse stock split, each 200 pre-split shares of common stock outstanding were automatically combined into one issued and outstanding share of common stock. The fractional shares that resulted from the reverse stock split were canceled by paying cash in lieu of the fair value. The number of outstanding shares of common stock were reduced from approximately 1.957 billion as of April 10, 2020 to approximately 9.784 million shares (without giving effect to the liquidation of fractional shares). The total number of shares of common stock that we are authorized to issue was reduced from 3,000,000,000 to 22,500,000 shares. All share and per share amounts in the accompanying condensed consolidated financial statements and notes thereto were retroactively adjusted for all periods presented to give effect to this reverse stock split, including reclassifying an amount equal to the reduction in par value of our common stock to additional paid-in capital.

*Voluntary Reorganization Under Chapter 11*

On June 28, 2020 (the "Petition Date"), we and certain of our subsidiaries (collectively, the "Debtors") filed voluntary petitions (the "Chapter 11 Cases") for relief (the "Bankruptcy Filing") under Chapter 11 of Title 11 of the United States Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). On June 29, 2020, the Bankruptcy Court entered an order authorizing the joint administration of the Chapter 11 Cases under the caption *In re Chesapeake Energy Corporation*, Case No. 20-33233 (DRJ). Subsidiaries with noncontrolling interests, consolidated variable interest entities and certain de minimis subsidiaries (collectively, the "Non-Filing Entities") were not part of the Bankruptcy Filing. The Non-Filing Entities will continue to operate in the ordinary course of business.

Commencing on June 28, 2020, we are operating as debtors-in-possession in accordance with the applicable provisions of the Bankruptcy Code. The Bankruptcy Court has granted first day motions filed by us that were designed primarily to mitigate the impact of the Chapter 11 Cases on our operations, customers and employees. As a result, we are able to conduct normal business activities and pay all associated obligations for the period following the Bankruptcy Filing and are authorized to pay owner royalties, employee wages and benefits, and certain vendors and suppliers in the ordinary course for goods and services provided. During the pendency of the Chapter 11 Cases, all transactions outside the ordinary course of business require the prior approval of the Bankruptcy Court.

During the Chapter 11 Cases, we expect our financial results to continue to be volatile as Restructuring activities and expenses, contract terminations and rejections, and claims assessments significantly impact our consolidated financial statements. As a result, our historical financial performance is likely not indicative of our financial performance after the date of the Bankruptcy Filing. In addition, we will incur significant professional fees and other costs in connection with preparation for the Chapter 11 Cases and expect that we will continue to incur significant professional fees and costs throughout our Chapter 11 Cases.

On October 13, 2020, we filed a notice with the Bankruptcy Court that we reached an agreement with Tapstone Energy as the “Stalking Horse” bidder to sell our Mid-Continent asset for $85 million in a 363 transaction under the Bankruptcy Code. A Bankruptcy Court supervised auction was held on November 10, 2020 in which other pre-qualified buyers submitted bids for the asset. We presented the results of the auction process to the Bankruptcy Court and the sale was approved on November 13, 2020. On December 11, 2020, we closed the transaction with Tapstone Energy for $130 million, subject to post-closing adjustments.

See Note 26 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a complete discussion of the Chapter 11 Cases.

**Liquidity and Capital Resources**

*Liquidity Overview*

Our primary sources of capital resources and liquidity have historically consisted of internally generated cash flows from operations, borrowings under certain credit agreements, dispositions of non-core assets and the capital markets when conditions are favorable. Our ability to issue additional indebtedness, dispose of assets or access the capital markets may be substantially limited or nonexistent during the Chapter 11 Cases and will require court approval in most instances. Accordingly, our liquidity will depend mainly on cash generated from operating activities and available funds under the DIP Credit Facility discussed below.

Filing of the Chapter 11 Cases constituted an event of default with respect to certain of our secured and unsecured debt obligations. As a result of the Chapter 11 Cases, the principal and interest due under these debt instruments became immediately due and payable. However, the creditors are stayed from taking any action as a result of the default under Section 362 of the Bankruptcy Code.

*Recent Events Affecting Liquidity*

On June 28, 2020, prior to the commencement of the Chapter 11 Cases, the Company entered into a commitment letter (the “Commitment Letter”) with certain of the lenders under the pre-petition revolving credit facility and/or their affiliates (collectively, the “Commitment Parties”), pursuant to which, and subject to the satisfaction of certain customary conditions, including the approval of the Bankruptcy Court, the Commitment Parties agreed to provide the Debtors with a post-petition senior secured super-priority debtor-in-possession revolving credit facility in an aggregate principal amount of up to approximately $2.104 billion (the “DIP Credit Facility”), consisting of a revolving loan facility of new money in an aggregate principal amount of up to $925 million, which includes a sub-facility of up to $200 million for the issuance of letters of credit, and an up to approximately $1.179 billion term loan that reflects the roll-up of a portion of outstanding borrowings under the pre-petition revolving credit facility. Pursuant to the Commitment Letter, the Commitment Parties also committed to provide, subject to certain conditions, an up to $2.5 billion exit credit facility, consisting of an up to $1.75 billion revolving credit facility (the “Exit Revolving Facility”) and an up to $750 million senior secured term loan facility (the “Exit Term Loan Facility” and, together with the Exit Revolving Facility, the “Exit Credit Facilities”). The terms and conditions of the DIP Credit Facility are set forth in the DIP Credit Agreement (the “DIP Credit Agreement”) attached to the Commitment Letter. The financing package provides us the capital necessary to fund our operations during the Court-supervised Chapter 11 reorganization proceedings. The proceeds of the DIP Credit Facility may be used for, among other things, post-petition working capital, permitted capital investments, general corporate purposes, letters of credit, administrative costs, premiums, expenses and fees for the transactions contemplated by the Chapter 11 Cases, payment of court approved adequate protection obligations, and other such purposes consistent with the DIP Credit Facility. On July 1, 2020, the Company, as borrower, entered into the DIP Credit Agreement along with the Debtor guarantors party thereto, MUFG Union Bank, N.A., as agent, and the other lender, issuer, and agent parties thereto with the other Debtors party thereto. On September 15, 2020, we entered into the first amendment to the DIP Credit Agreement. The amendment, among other things, amends the maximum hedging covenant to allow the Debtors to enter into additional non-speculative hedge agreements based on forecasted production.

We believe our cash flow from operations, borrowing capacity under the DIP Credit Facility and cash on hand will provide sufficient liquidity during the bankruptcy process. We expect to incur significant costs associated with the bankruptcy process, including fees for legal, financial and restructuring advisors to the Company, certain of our creditors and royalty interest owners. Therefore, our ability to obtain confirmation of the Plan in a timely manner is critical to ensuring our liquidity is sufficient during the bankruptcy process.

Our ability to continue as a going concern is contingent on our ability to comply with the financial and other covenants contained in our DIP Credit Facility and our ability to successfully implement the Plan and obtain exit financing, among other factors. As a result of the Bankruptcy Filing, the realization of assets and the satisfaction of liabilities are subject to uncertainty. While operating as debtors-in-possession under Chapter 11, we may sell or otherwise dispose of or liquidate assets or settle liabilities, subject to the approval of the Bankruptcy Court or as otherwise permitted in the ordinary course of business (and subject to restrictions contained in the DIP Credit Facility), for amounts other than those reflected in the accompanying consolidated financial statements. Further, the Plan could materially change the amounts and classifications of assets and liabilities reported in the consolidated financial statements. The factors noted above raise substantial doubt about our ability to continue as a going concern.

*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 (mmbbls) | Average NYMEX Price |
|---|---|---|---|
| 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 (bcf) | Average NYMEX Price |
|---|---|---|---|
| 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) | $ 47 |

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

## INDEX TO FINANCIAL STATEMENTS
## CHESAPEAKE ENERGY CORPORATION

Supplementary Information:

## 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.

*Substantial Doubt about the Company’s Ability to Continue as a Going Concern*

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 26 to the consolidated financial statements, Chesapeake Energy Corporation and certain of its subsidiaries filed for voluntary reorganization under Chapter 11 of the US Bankruptcy Code on June 28, 2020, which raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to this matter are also described in Note 26. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

*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 Management’s Report on Internal Control Over Financial Reporting appearing under Item 9A. 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, except with respect to our opinion on the consolidated financial statements insofar as it relates to the matter that raises substantial doubt about the Company’s ability to continue as a going concern and the effects of the reverse stock split discussed in Note 26, as to which the date is February 2, 2021

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

**CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS**

| | December 31, | |
|---|---|---|
| | **2019** | **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, 22,500,000 and 15,000,000 shares authorized: 9,772,793 and 4,568,499 shares issued[(a)] | — | — |
| Additional paid-in capital | 16,973 | 14,387 |
| Accumulated deficit | (14,220) | (13,912) |
| Accumulated other comprehensive income (loss) | 12 | (23) |
| Less: treasury stock, at cost; 26,224 and 16,232 common shares[(a)] | (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 |

(a) Amounts and shares have been retroactively adjusted to reflect a 1-for-200 (1:200) reverse stock split effective April 14, 2020. See Note 26 for additional information.

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:**[(a)] | | | |
| Basic | $ (49.97) | $ 29.26 | $ (139.32) |
| Diluted | $ (49.97) | $ 29.26 | $ (139.32) |
| **WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):**[(a)] | | | |
| Basic | 8,325 | 4,546 | 4,529 |
| Diluted | 8,325 | 4,546 | 4,529 |

(a) All share and per share information has been retroactively adjusted to reflect a 1-for-200 (1:200) reverse stock split effective April 14, 2020. See Note 26 for additional information.

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:[(a)]** | | | |
| Balance, beginning of period | — | — | — |
| Common shares issued for WildHorse Merger | — | — | — |
| Exchange of senior notes and convertible notes | — | — | — |
| Balance, end of period | — | — | — |
| **ADDITIONAL PAID-IN CAPITAL:[(a)]** | | | |
| Balance, beginning of period | 14,387 | 14,446 | 14,495 |
| Common shares issued for WildHorse Merger | 2,037 | — | — |
| Stock-based compensation | 27 | 33 | 54 |
| Exchange of contingent convertible notes for 366,945, 0 and 0 shares of common stock | 135 | — | — |
| Exchange of senior notes for 1,177,817, 0 and 0 shares of common stock | 440 | — | — |
| Exchange of preferred stock for 51,839, 0, and 49,829 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 | 16,973 | 14,387 | 14,446 |
| **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.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2019 | 2018 | 2017 |
| | ($ in millions) | | |
| **TREASURY STOCK – COMMON:**[(a)] | | | |
| Balance, beginning of period | (31) | (31) | (27) |
| Purchase of 14,391, 7,550, and 6,032 shares for company benefit plans | (7) | (4) | (7) |
| Release of 4,398, 2,519 and 932 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 |

(a) Amounts and shares have been retroactively adjusted to reflect a 1-for-200 (1:200) reverse stock split effective April 14, 2020. See Note 26 for additional information.

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 Und Successful Effort** | |
| | **($ in millions except per share data)** | | | | | |
| Proved oil and natural gas properties ($488 and $755 attributable to our VIE) | $ | 75,148 | $ | (44,383) | $ | 30,7 |
| Unproved properties | $ | 3,203 | $ | (1,030) | $ | 2,1 |
| Total Property and Equipment, at Cost | $ | 80,161 | $ | (45,413) | $ | 34,7 |
| Less: accumulated depreciation, depletion and amortization (($468) and ($713) attributable to our VIE) | $ | (66,626) | $ | 46,624 | $ | (20,0 |
| Total Property and Equipment, Net | $ | 13,545 | $ | 1,211 | $ | 14,7 |
| Total Assets | $ | 14,982 | $ | 1,211 | $ | 16,1 |
| Other current liabilities | $ | 1,377 | $ | 55 | $ | 1,4 |
| Total Current Liabilities | $ | 2,337 | $ | 55 | $ | 2,3 |
| Other long-term liabilities | $ | 116 | $ | 9 | $ | 1 |
| Total Long-Term Liabilities | $ | 9,391 | $ | 9 | $ | 9,4 |
| Accumulated deficit | $ | (15,451) | $ | 1,231 | $ | (14,2 |
| Total Chesapeake Stockholders' Equity | $ | 3,133 | $ | 1,231 | $ | 4,3 |
| Noncontrolling interests | $ | 121 | $ | (84) | $ | [illegible] |
| Total Equity | $ | 3,254 | $ | 1,147 | $ | 4,4 |
| Total Liabilities and Equity | $ | 14,982 | $ | 1,211 | $ | 16,1 |

| | December 31, 2018 | | | | | |
|---|---|---|---|---|---|---|
| **CONSOLIDATED BALANCE SHEETS** | | **As Reported Under Full Cost** | | **Adjustment** | | **As Reported Und Successful Effort** |
| | ($ in millions except per share data) | | | | | |
| Proved oil and natural gas properties ($488 and $755 attributable to our VIE) | $ | 69,642 | $ | (44,235) | $ | 25,40 |
| Unproved properties | $ | 2,337 | $ | (776) | $ | 1,56 |
| Total Property and Equipment, at Cost | $ | 73,700 | $ | (45,011) | $ | 28,68 |
| Less: accumulated depreciation, depletion and amortization (($461) and ($707) attributable to our VIE) | $ | (64,685) | $ | 46,799 | $ | (17,88 |
| Total Property and Equipment, Net | $ | 9,030 | $ | 1,788 | $ | 10,81 |
| Total Assets | $ | 10,947 | $ | 1,788 | $ | 12,73 |
| Other current liabilities | $ | 1,540 | $ | 59 | $ | 1,59 |
| Total Current Liabilities | $ | 2,828 | $ | 59 | $ | 2,88 |
| Other long-term liabilities | $ | 156 | $ | 63 | $ | 21 |
| Total Long-Term Liabilities | $ | 7,652 | $ | 63 | $ | 7,71 |
| Accumulated deficit | $ | (15,660) | $ | 1,748 | $ | (13,91 |
| Total Chesapeake Stockholders’ Equity | $ | 344 | $ | 1,748 | $ | 2,09 |
| Noncontrolling interests | $ | 123 | $ | (82) | $ | 4 |
| Total Equity | $ | 467 | $ | 1,666 | $ | 2,13 |
| Total Liabilities and Equity | $ | 10,947 | $ | 1,788 | $ | 12,73 |

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[(a)] | $ 12.13 | $ (62.10) | $ (49.97) |
| Earnings (loss) per common share diluted[(a)] | $ 12.13 | $ (62.10) | $ (49.97) |

| | 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[(a)] | 170.48 | (141.22) | 29.26 |
| Earnings per common share diluted[(a)] | 170.48 | (141.22) | 29.26 |

| | 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[(a)] | $ 179.51 | $ (318.83) | $ (139.32) |
| Earnings (loss) per common share diluted[(a)] | $ 179.43 | $ (318.75) | $ (139.32) |

(a) All per share information has been retroactively adjusted to reflect a 1-for-200 (1:200) reverse stock split effective April 14, 2020. See Note 26 for additional information.

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

| CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME | Year Ended December 31, 2019 | | |
|---|---|---|---|
| | **Under Full Cost** | **Adjustment** | **As Reported Under Successful Effort** |
| | ($ in millions except per share data) | | |
| Net income (loss) | $ 211 | $ (519) | $ (3 |
| Comprehensive income (loss) | $ 246 | $ (519) | $ (2 |
| Comprehensive income attributable to noncontrolling interests | $ (2) | $ 2 | $ |
| Comprehensive income (loss) attributable to Chesapeake | $ 244 | $ (517) | $ (2 |

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

| CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME | Year Ended December 31, 2017 | | |
|---|---|---|---|
| | **As Reported Under Full Cost** | **Adjustment** | **As Reported Under Successful Effort** |
| | ($ in millions except per share data) | | |
| Net income (loss) | $ 953 | $ (1,455) | $ (5 |
| Comprehensive income (loss) | $ 992 | $ (1,455) | $ (4 |
| Comprehensive income attributable to noncontrolling interests | $ (4) | $ 1 | $ |
| Comprehensive income (loss) attributable to Chesapeake | $ 988 | $ (1,454) | $ (4 |

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** | | **Adjustment** | | **As Reported Under Successful Effort** | |
| | **($ in millions except per share data)** | | | | | |
| Net income (loss) | $ | 211 | $ | (519) | $ | (3 |
| Depreciation, depletion and amortization | $ | 1,616 | $ | 648 | $ | 2,2 |
| Gain on sale of oil and gas properties | $ | (15) | $ | 15 | $ | |
| Gain on sales of assets | $ | — | $ | (43) | $ | ( |
| Impairments | $ | 344 | $ | (333) | $ | |
| Exploratory dry hole expense and leasehold impairments | $ | — | $ | 49 | $ | |
| Other | $ | (2) | $ | (2) | $ | |
| (Decrease) increase in accounts payable, accrued liabilities and other | $ | (567) | $ | (63) | $ | (6 |
| Net cash provided by operating activities | $ | 1,871 | $ | (248) | $ | 1,6 |
| Drilling and completion costs | $ | (2,260) | $ | 80 | $ | (2,1 |
| Acquisition of proved and unproved properties | $ | (203) | $ | 168 | $ | ( |
| Net cash used by investing activities | $ | (2,728) | $ | 248 | $ | (2,4 |

| **CONSOLIDATED STATEMENTS OF CASH FLOWS** | **Year Ended December 31, 2018** | | | | | |
|---|---|---|---|---|---|---|
| | **As Reported Under Full Cost** | | **Adjustment** | | **As Reported Under Successful Effort** | |
| | **($ in millions except per share data)** | | | | | |
| Net income | $ | 877 | $ | (649) | $ | 2 |
| Depreciation, depletion and amortization | $ | 1,145 | $ | 592 | $ | 1,7 |
| Loss on sale of oil and gas properties | $ | 578 | $ | (578) | $ | |
| Losses on sales of assets | $ | — | $ | 264 | $ | 2 |
| Impairments | $ | 53 | $ | 78 | $ | 1 |
| Exploratory dry hole expense and leasehold impairments | $ | — | $ | 96 | $ | |
| Other | $ | (108) | $ | (10) | $ | (1 |
| Increase in accounts payable, accrued liabilities and other | $ | 138 | $ | (63) | $ | |
| Net cash provided by operating activities | $ | 2,000 | $ | (270) | $ | 1,7 |
| Drilling and completion costs | $ | (1,958) | $ | 110 | $ | (1,8 |
| Acquisition of proved and unproved properties | $ | (288) | $ | 160 | $ | (1 |
| Net cash provided by investing activities | $ | 185 | $ | 270 | $ | 4 |

| CONSOLIDATED STATEMENTS OF CASH FLOWS | Year Ended December 31, 2017 | | | | | |
|---|---|---|---|---|---|---|
| | As Reported Under Full Cost | | Adjustment | | As Reported Under Successful Effort | |
| | ($ in millions except per share data) | | | | | |
| Net income (loss) | $ | 953 | $ | (1,455) | $ | (50 |
| Depreciation, depletion and amortization | $ | 995 | $ | 702 | $ | 1,69 |
| Gains on sales of assets | $ | — | $ | (476) | $ | (47 |
| Impairments | $ | 5 | $ | 809 | $ | 8 |
| Exploratory dry hole expense and leasehold impairments | $ | — | $ | 214 | $ | 2 |
| Other | $ | (135) | $ | 3 | $ | (13 |
| Decrease in accounts payable, accrued liabilities and other | $ | (308) | $ | (67) | $ | (37 |
| Net cash provided by operating activities | $ | 745 | $ | (270) | $ | 47 |
| Drilling and completion costs | $ | (2,186) | $ | 73 | $ | (2,11 |
| Acquisition of proved and unproved properties | $ | (285) | $ | 197 | $ | (8 |
| Net cash used in investing activities | $ | (1,188) | $ | 270 | $ | (91 |

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

| CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY | Year Ended December 31, 2019 | | |
|---|---|---|---|
| | Under Full Cost | Adjustment | As Reported Under Successful Effort |
| | ($ in millions except per share data) | | |
| Accumulated deficit, beginning of period | $ (15,660) | $ 1,748 | $ (13,9 |
| Net income (loss) attributable to Chesapeake | $ 209 | $ (517) | $ (3 |
| Accumulated deficit, end of period | $ (15,451) | $ 1,231 | $ (14,2 |
| Total Chesapeake stockholders' equity | $ 3,133 | $ 1,231 | $ 4,3 |
| Noncontrolling interests, beginning of period | $ 123 | $ (82) | $ |
| Net income attributable to noncontrolling interests | $ 2 | $ (2) | $ |
| Noncontrolling interests, end of period | $ 121 | $ (84) | $ |
| Total equity | $ 3,254 | $ 1,147 | $ 4,4 |

| CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY | Year Ended December 31, 2018 | | |
|---|---|---|---|
| | As Reported Under Full Cost | Adjustment | As Reported Under Successful Effort |
| | ($ in millions except per share data) | | |
| Accumulated deficit, beginning of period | $ (16,525) | $ 2,395 | $ (14,1 |
| Net income attributable to Chesapeake | $ 873 | $ (647) | $ 2 |
| Accumulated deficit, end of period | $ (15,660) | $ 1,748 | $ (13,9 |
| Total Chesapeake stockholders' equity | $ 344 | $ 1,748 | $ 2,0 |
| Noncontrolling interests, beginning of period | $ 124 | $ (80) | $ |
| Net income attributable to noncontrolling interests | $ 4 | $ (2) | $ |
| Noncontrolling interests, end of period | $ 123 | $ (82) | $ |
| Total equity | $ 467 | $ 1,666 | $ 2,1 |

| CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY | Year Ended December 31, 2017 | | |
|---|---|---|---|
| | As Reported Under Full Cost | Adjustment | As Reported Under Successful Effort |
| | ($ in millions except per share data) | | |
| Accumulated deficit, beginning of period | $ (17,474) | $ 3,849 | $ (13,6 |
| Net income (loss) attributable to Chesapeake | $ 949 | $ (1,454) | $ (5 |
| Accumulated deficit, end of period | $ (16,525) | $ 2,395 | $ (14,1 |
| Total Chesapeake stockholders' equity (deficit) | $ (496) | $ 2,395 | $ 1,8 |
| Noncontrolling interests, beginning of period | $ 128 | $ (79) | $ |
| Net income attributable to noncontrolling interests | $ 4 | $ (1) | $ |
| Noncontrolling interests, end of period | $ 124 | $ (80) | $ |
| Total equity (deficit) | $ (372) | $ 2,315 | $ 1,9 |

## 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 3.6 million Reverse Stock Split adjusted 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 3.6 million Reverse Stock Split adjusted Chesapeake common shares issued at closing at $568 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[(a)] | $ (51.77) | $ 42.89 |
| Diluted[(a)] | $ (51.77) | $ 42.89 |

___________________________________________

(a) All per share information has been retroactively adjusted to reflect a 1-for-200 (1:200) reverse stock split effective April 14, 2020. See Note 26 for additional information.

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 thousands) | | |
| Common stock equivalent of our preferred stock outstanding[(a)] | 290 | 298 | 298 |
| Common stock equivalent of our convertible senior notes outstanding[(a)] | 621 | 729 | 729 |
| Common stock equivalent of our preferred stock outstanding prior to exchange[(a)] | 5 | — | 4 |
| Participating securities[(a)] | 2 | 6 | 4 |

(a) Amount has been retroactively adjusted to reflect a 1-for-200 (1:200) reverse stock split effective April 14, 2020. See Note 26 for additional information.

## 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 Exchange |
|---|---|---|
| | | **($ in millions)** |
| 7.00% senior notes due 2024 | $ | 22 |
| 8.00% senior notes due 2025 | | 99 |
| 8.00% senior notes due 2026 | | 87 |
| 7.5% senior notes due 2026 | | 28 |
| 8.00% senior notes due 2027 | | 83 |
| Total | $ | 3,21 |

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 | 4,568 | 4,543 | 4,481 |
| Common shares issued for WildHorse Merger[(a)] | 3,587 | — | — |
| Exchange of senior notes[(b)] | 1,178 | — | — |
| Exchange of convertible notes[(b)] | 367 | — | — |
| Exchange of preferred stock | 52 | — | 50 |
| Restricted stock issuances (net of forfeitures and cancellations)[(c)] | 21 | 25 | 12 |
| Shares issued as of December 31 | 9,773 | 4,568 | 4,543 |

(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 15,000,000 shares to 22,500,000 shares, adjusted for our Reverse Stock Split.

*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 | 0.1984 | $ 5,039.59 | May 17, 2015 | $ 6,551.46 |
| 5.75% (series A) cumulative convertible non-voting | May 2010 | $ 1,000 | Any time | 0.1918 | $ 5,215.02 | May 17, 2015 | $ 6,779.52 |
| 4.50% cumulative convertible | September 2005 | $ 100 | Any time | 0.0123 | $ 8,142.99 | September 15, 2010 | $ 10,585.89 |
| 5.00% cumulative convertible (series 2005B) | November 2005 | $ 100 | Any time | 0.0139 | $ 7,208.51 | November 15, 2010 | $ 9,371.06 |

(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 51,839 Reverse Stock Split adjusted 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 37,210 Reverse Stock Split adjusted shares of common stock, holders of our 5.75% (Series A) Cumulative Convertible Preferred Stock exchanged 12,500 shares into 6,029 Reverse Stock Split adjusted shares of common stock and holders of our 5.00% (Series 2005B) Cumulative Convertible Preferred Stock exchanged 150,948 shares into 6,588 Reverse Stock Split adjusted 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 358,000 Reverse Stock Split adjusted 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 0.005 Reverse Stock Split adjusted share; (ii) each share issued pursuant to awards other than options and SARs reduces the number of shares available by 0.0106 Reverse Stock Split adjusted 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, 149,327 Reverse Stock Split adjusted 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[(a)] | | Weighted Average Grant Date Fair Value[(a)] |
|---|---|---|---|
| | (in thousands) | | |
| Unvested restricted stock as of January 1, 2019 | 59 | $ | 886 |
| Granted | 30 | $ | 530 |
| Vested | (30) | $ | 876 |
| Forfeited | (7) | $ | 744 |
| Unvested restricted stock as of December 31, 2019 | 52 | $ | 710 |
| | | | |
| Unvested restricted stock as of January 1, 2018 | 66 | $ | 1,274 |
| Granted | 30 | $ | 746 |
| Vested | (29) | $ | 1,534 |
| Forfeited | (8) | $ | 1,204 |
| Unvested restricted stock as of December 31, 2018 | 59 | $ | 886 |
| | | | |
| Unvested restricted stock as of January 1, 2017 | 45 | $ | 2,278 |
| Granted | 49 | $ | 1,080 |
| Vested | (22) | $ | 2,746 |
| Forfeited | (6) | $ | 1,664 |
| Unvested restricted stock as of December 31, 2017 | 66 | $ | 1,274 |

(a) Amount has been retroactively adjusted to reflect a 1-for-200 (1:200) reverse stock split effective April 14, 2020. See Note 26 for additional information.

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[(a)] | Weighted Average Exercise Price Per Share[(a)] | Weighted Average Contract Life in Years | Aggregate Intrinsic Value[(b)] |
|---|---|---|---|---|
| | (in thousands) | | | ($ in millions) |
| Outstanding as of January 1, 2019 | 90 | $ 1,440 | 7.15 | $ — |
| Granted | 5 | $ 594 | | |
| Exercised | — | $ — | | $ — |
| Expired | (2) | $ 1,272 | | |
| Forfeited | (3) | $ 794 | | |
| Outstanding as of December 31, 2019 | 90 | $ 1,420 | 5.70 | $ — |
| Exercisable as of December 31, 2019 | 65 | $ 1,656 | 4.86 | $ — |
| | | | | |
| Outstanding as of January 1, 2018 | 81 | $ 1,650 | 7.73 | $ 1 |
| Granted | 18 | $ 602 | | |
| Exercised | — | $ — | | $ — |
| Expired | (3) | $ 2,766 | | |
| Forfeited | (6) | $ 1,090 | | |
| Outstanding as of December 31, 2018 | 90 | $ 1,440 | 7.15 | $ — |
| Exercisable as of December 31, 2018 | 41 | $ 2,146 | 5.73 | $ — |
| | | | | |
| Outstanding as of January 1, 2017 | 42 | $ 2,376 | 7.22 | $ 14 |
| Granted | 46 | $ 1,090 | | |
| Exercised | — | $ — | | $ — |
| Expired | (2) | $ 3,700 | | |
| Forfeited | (5) | $ 1,824 | | |
| Outstanding as of December 31, 2017 | 81 | $ 1,650 | 7.73 | $ 1 |
| Exercisable as of December 31, 2017 | 22 | $ 3,030 | 5.26 | $ — |

(a) Amount has been retroactively adjusted to reflect a 1-for-200 (1:200) reverse stock split effective April 14, 2020. See Note 26 for additional information.

(b) 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, | | Estimated Useful Life |
|---|---|---|---|
| | 2019 | 2018 | |
| | ($ 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 | Consolidat |
|---|---|---|---|---|---|
| **REVENUES AND OTHER:** | | | | | |
| Oil, natural gas and NGL | $ — | $ 4,962 | $ 23 | $ — | $ 4,98 |
| Marketing | — | 4,511 | — | — | 4,51 |
| Total Revenues | — | 9,473 | 23 | — | 9,49 |
| Other | — | 67 | — | — | 6 |
| Gains on sales of assets | — | 476 | — | — | 47 |
| Total Revenues and Other | — | 10,016 | 23 | — | 10,03 |
| **OPERATING EXPENSES:** | | | | | |
| Oil, natural gas and NGL production | — | 517 | — | — | 51 |
| Oil, natural gas and NGL gathering, processing and transportation | — | 1,463 | 8 | — | 1,47 |
| Severance and ad valorem taxes | — | 133 | 1 | — | 13 |
| Exploration | — | 235 | — | — | 23 |
| Marketing | — | 4,598 | — | — | 4,59 |
| General and administrative | 1 | 330 | 2 | — | 33 |
| Provision for legal contingencies, net | (79) | 41 | — | — | (3 |
| Depreciation, depletion and amortization | — | 1,688 | 9 | — | 1,69 |
| Impairments | — | 814 | — | — | 81 |
| Other operating expense | — | 416 | — | — | 41 |
| Total Operating (Income) Expenses | (78) | 10,235 | 20 | — | 10,17 |
| **INCOME (LOSS) FROM OPERATIONS** | 78 | (219) | 3 | — | (13 |
| **OTHER INCOME (EXPENSE):** | | | | | |
| Interest expense | (599) | (2) | — | — | (60 |
| Gains on purchases or exchanges of debt | 233 | — | — | — | 23 |
| Other income | 1 | 5 | — | — | |
| Equity in net losses of subsidiary | (216) | — | — | 216 | - |
| Total Other Income (Expense) | (581) | 3 | — | 216 | (36 |
| **INCOME (LOSS) BEFORE INCOME TAXES** | (503) | (216) | 3 | 216 | (50 |
| **INCOME TAX EXPENSE** | 2 | — | — | — | |
| **NET INCOME (LOSS)** | (505) | (216) | 3 | 216 | (50 |
| Net income attributable to noncontrolling interests | — | — | (3) | — | |
| **NET LOSS ATTRIBUTABLE TO CHESAPEAKE** | (505) | (216) | — | 216 | (50 |
| Other comprehensive income | — | 39 | — | — | 3 |
| **COMPREHENSIVE LOSS ATTRIBUTABLE TO CHESAPEAKE** | $ (505) | $ (177) | $ — | $ 216 | $ (46 |

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

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidat |
|---|---|---|---|---|---|
| **CASH FLOWS FROM OPERATING ACTIVITIES:** | | | | | |
| Net Cash Provided By Operating Activities | $ 1 | $ 1,270 | $ 356 | $ (4) | $ 1,6 |
| **CASH FLOWS FROM INVESTING ACTIVITIES:** | | | | | |
| Drilling and completion costs | — | (1,548) | (632) | — | (2,1 |
| Business combination, net | — | (381) | 28 | — | (3 |
| Acquisitions of proved and unproved properties | — | (35) | — | — | ( |
| Proceeds from divestitures of proved and unproved properties | — | 130 | — | — | 1 |
| Additions to other property and equipment | — | (32) | (16) | — | ( |
| Proceeds from sales of other property and equipment | — | 6 | — | — | |
| Net Cash Used In Investing Activities | — | (1,860) | (620) | — | (2,4 |
| **CASH FLOWS FROM FINANCING ACTIVITIES:** | | | | | |
| Proceeds from revolving credit facility borrowings | 9,839 | — | 837 | — | 10,6 |
| Payments on revolving credit facility borrowings | (8,668) | — | (1,512) | — | (10,1 |
| Proceeds from issuance of senior notes, net | 108 | — | — | — | 1 |
| Proceeds from issuance of term loan, net | 1,455 | — | — | — | 1,4 |
| Cash paid to purchase debt | (380) | — | (693) | — | (1,0 |
| Cash paid for preferred stock dividends | (91) | — | — | — | ( |
| Contribution from parent | (1,644) | — | 1,644 | — | |
| Other financing activities | (24) | (8) | (8) | 4 | ( |
| Intercompany advances, net | (713) | 713 | — | — | |
| Net Cash Provided By (Used In) Financing Activities | (118) | 705 | 268 | 4 | 8 |
| Net increase (decrease) in cash and cash equivalents | (117) | 115 | 4 | — | |
| Cash and cash equivalents, beginning of period | 4 | 1 | 1 | (2) | |
| Cash and cash equivalents, end of period | $ (113) | $ 116 | $ 5 | $ (2) | $ |

**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) | $ 4 |
| **CASH FLOWS FROM INVESTING ACTIVITIES:** | | | | | |
| Drilling and completion costs | — | (2,113) | — | — | (2,1 |
| Acquisitions of proved and unproved properties | — | (88) | — | — | (8 |
| Proceeds from divestitures of proved and unproved properties | — | 1,249 | — | — | 1,24 |
| Additions to other property and equipment | — | (21) | — | — | (2 |
| Other investing activities | — | 55 | — | — | 5 |
| Net Cash Used In Investing Activities | — | (918) | — | — | (91 |
| **CASH FLOWS FROM FINANCING ACTIVITIES:** | | | | | |
| Proceeds from revolving credit facility borrowings | 7,771 | — | — | — | 7,77 |
| Payments on revolving credit facility borrowings | (6,990) | — | — | — | (6,99 |
| Proceeds from issuance of senior notes, net | 1,585 | — | — | — | 1,58 |
| Cash paid to purchase debt | (2,592) | — | — | — | (2,59 |
| Cash paid for preferred stock dividends | (183) | — | — | — | (18 |
| Other financing activities | (39) | (5) | (13) | 32 | (2 |
| Intercompany advances, net | (456) | 456 | — | — | |
| Net Cash Provided by (Used In) Financing Activities | (904) | 451 | (13) | 32 | (43 |
| Net increase (decrease) in cash and cash equivalents | (899) | (1) | 1 | 22 | (87 |
| Cash and cash equivalents, beginning of period | 904 | 2 | 1 | (25) | 88 |
| Cash and cash equivalents, end of period | $ 5 | $ 1 | $ 2 | $ (3) | $ |

## 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.

*Reverse Stock Split*

On April 13, 2020, our Board of Directors and our shareholders approved a 1-for-200 (1:200) reverse stock split of our common stock and a reduction of the total number of authorized shares of our common stock as determined by a formula based on two-thirds of the reverse stock split ratio. The reverse stock split became effective as of the close of business on April 14, 2020. Our common stock began trading on a split-adjusted basis on the NYSE at the market open on April 15, 2020. The par value of the common stock was not adjusted as a result of the reverse stock split.

The reverse stock split was intended to, among other things, increase the per share trading price of our common shares to satisfy the $1.00 minimum closing price requirement for continued listing on the NYSE. As a result of the reverse stock split, each 200 pre-split shares of common stock outstanding were automatically combined into one issued and outstanding share of common stock. The fractional shares that resulted from the reverse stock split were canceled by paying cash in lieu of the fair value. The number of outstanding shares of common stock were reduced from approximately 1.957 billion as of April 10, 2020 to approximately 9.784 million shares (without giving effect to the liquidation of fractional shares). The total number of shares of common stock that we are authorized to issue was reduced from 3,000,000,000 to 22,500,000 shares. All share and per share amounts in the accompanying condensed consolidated financial statements and notes thereto were retroactively adjusted for all periods presented to give effect to this reverse stock split, including reclassifying an amount equal to the reduction in par value of our common stock to additional paid-in capital.

*Chapter 11 Proceedings*

On June 28, 2020, (the “Petition Date”) we and certain of our subsidiaries (collectively, the “Debtors”) filed voluntary petitions (the “Chapter 11 Cases”) for relief (the “Bankruptcy Filing”) under Chapter 11 of Title 11 of the United States Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the Southern District of Texas (the “Bankruptcy Court”). On June 29, 2020, the Bankruptcy Court entered an order authorizing the joint administration of the Chapter 11 Cases under the caption *In re Chesapeake Energy Corporation*, Case No. 20-33233. Subsidiaries with noncontrolling interests, consolidated variable interest entities and certain de minimis subsidiaries (collectively, the “Non-Filing Entities”) were not part of the Bankruptcy Filing. The Non-Filing Entities will continue to operate in the ordinary course of business.

The Bankruptcy Court confirmed the Debtors’ joint plan of reorganization (the “Plan”) on January 13, 2021 and the Debtors subsequently have 30 days to emerge from bankruptcy. The Company’s bankruptcy proceedings and related matters have been summarized below.

*Debtor-In-Possession.* We are currently operating as debtors in possession in accordance with the applicable provisions of the Bankruptcy Code. The Bankruptcy Court granted the first day relief we requested that was designed primarily to mitigate the impact of the Chapter 11 Cases on our operations, customers and employees. As a result, we are able to conduct normal business activities and pay all associated obligations for the period following the Bankruptcy Filing and are also authorized to pay owner royalties, employee wages and benefits, and certain vendors and suppliers in the ordinary course for goods and services provided prior to the Bankruptcy Filing. During the pendency of the Chapter 11 Cases, all transactions outside the ordinary course of business require the prior approval of the Bankruptcy Court.

*Automatic Stay.* Subject to certain specific exceptions under the Bankruptcy Code, the filing of the Chapter 11 Cases automatically stayed all judicial or administrative actions against us and efforts by creditors to collect on or otherwise exercise rights or remedies with respect to pre-petition claims. Absent an order from the Bankruptcy Court, substantially all of the Debtors’ pre-petition liabilities are subject to settlement under the Bankruptcy Code.

*Restructuring Support Agreement.* On June 28, 2020, the Debtors entered into a restructuring support agreement (the "RSA") with certain holders (collectively, the "Consenting Stakeholders") of (i) obligations under that certain Amended and Restated Credit Agreement, dated as of September 12, 2018, by and among Chesapeake, as borrower, the Debtor guarantors party thereto, MUFG Union Bank, N.A., as administrative agent, and the other lender, issuer, and agent parties thereto (the "pre-petition revolving credit facility"); (ii) obligations under that certain Term Loan Agreement, dated as of December 19, 2019, by and among Chesapeake, as borrower, the Debtor guarantors party thereto, GLAS USA LLC., as administrative agent, and the lender parties thereto (the "FLLO Term Loan"); and (iii) obligations under the 11.5% Senior Secured Second Lien Notes due 2025 (the "Second Lien Notes") issued pursuant to that certain indenture, dated as of December 19, 2019, by and among Chesapeake, as issuer, certain guarantors party thereto, and Deutsche Bank Trust Company Americas, as trustee and collateral trustee to support a restructuring (the "Restructuring") on the terms set forth in the RSA and the term sheet annexed to the RSA (the "Restructuring Term Sheet"). Certain Consenting Stakeholders also hold Unsecured Notes (as defined in the Restructuring Term Sheet) and their Unsecured Notes are also subject to the terms and obligations under the RSA. The RSA contemplates that the Company will implement the Restructuring through the Chapter 11 Cases pursuant to a consensual plan of reorganization (the "Plan") filed in the Chapter 11 proceedings as described further below.

The RSA contains certain covenants on the part of each of the Company and the Consenting Stakeholders, including limitations on the parties' ability to pursue alternative transactions (subject to customary provisions regarding the ability of the Company's Board of Directors to satisfy its fiduciary duties), commitments by the Consenting Stakeholders to vote in favor of the Plan and commitments of the Company and the Consenting Stakeholders to negotiate in good faith to finalize the documents and agreements contemplated by and required to implement the Plan. The RSA also provides for certain conditions to the obligations of the parties and for termination upon the occurrence of certain events, including, without limitation, the failure to achieve certain milestones and certain breaches by the parties under the RSA. One such condition is the requirement to obtain sufficient savings on certain midstream obligations (as determined by the required plan sponsors, defined in the RSA) through rejection of such contracts and/or renegotiation of their terms.

*Plan of Reorganization.* If the Debtors successfully implement the Plan, obtain exit financing, and certain conditions precedent in the RSA, the Debtors would exit Chapter 11 pursuant to the Plan. Under the Plan, the claims against and interests in the Debtors are organized into classes based, in part, on their respective priorities. Below is a summary of the treatment that the stakeholders of the Company would receive under the Plan upon the emergence from bankruptcy:

- *Holders of Other Secured Claims*. Each holder of Other Secured Claims (as defined in the Plan) would receive, at the Company's option and in consultation with a requisite number of holders of claims who are backstopping a rights offering pursuant to the Plan: (a) payment in full in cash; (b) the collateral securing its secured claim; (c) reinstatement of its secured claim; or (d) such other treatment rendering its secured claim unimpaired in accordance with Section 1124 of the Bankruptcy Code.

- *Holders of Other Priority Claims*. Each holder of Other Priority Claims (as defined in the Plan) would receive treatment in a manner consistent with Section 1129(a)(9) of the Bankruptcy Code.

- *Holders of Pre-Petition Revolving Credit Facility Claims*. On the effective date of the Plan (the "Plan Effective Date"), each holder of obligations under the pre-petition revolving credit facility would receive, at such holder's option, its pro rata share of either Tranche A RBL Exit Facility Loans or Tranche B RBL Exit Facility Loans (each as defined in the Exit Facilities Term Sheet, defined below), each on a dollar for dollar basis.

- *Holders of FLLO Term Loan Facility Claims*. On the Plan Effective Date, each holder of obligations under the FLLO Term Loan Facility would receive its pro rata share of (i) 76% of the reorganized Company's new common equity interests (the "New Common Stock"), subject to the terms set forth in the Restructuring Term Sheet and (ii) the right to participate in a rights offering on the terms set forth in the Restructuring Term Sheet.

- *Holders of Second Lien Notes Claims*. On the Plan Effective Date, each holder of the Second Lien Notes would receive its pro rata share of (i) 12% of the New Common Stock, subject to the terms set forth in the Restructuring Term Sheet, (ii) the right to participate in a rights offering on the terms set forth in the

Restructuring Term Sheet, and (iii) warrants to purchase 10% of the New Common Stock on certain terms set forth in the Restructuring Term Sheet, warrants to purchase another 10% of the New Common Stock on certain other terms set forth in the Restructuring Term Sheet, and 50% of warrants to purchase another 10% of the New Common Stock on certain other terms set forth in the Restructuring Term Sheet (the "New Class C Warrants").

- *Holders of Unsecured Notes Claims*. On the Plan Effective Date, each holder of the Unsecured Notes (as defined in the Plan) would receive its pro rata share of (i) 12% of the New Common Stock, subject to the terms set forth in the Restructuring Term Sheet, and (ii) 50% of the New Class C Warrants (the “Unsecured Claims Recovery”).
- *Holders of General Unsecured Claims*. On the Plan Effective Date, each holder of allowed general unsecured claims would receive its pro rata share of the Unsecured Claims Recovery; provided that to the extent such allowed general unsecured claim is a Convenience Claim (as defined in the Plan), such holder shall receive the Convenience Claim Distribution (as defined in the Plan).
- *Equity Holders*. Each holder of an equity interest in Chesapeake, including our common and preferred stock, would have such interest canceled, released, and extinguished without any distribution.
- Although the Plan has been confirmed by the Bankruptcy Court, there is no assurance the Company will successfully implement the Plan, obtain exit financing and certain conditions precedent in the RSA.

*DIP Credit Facility.* On June 28, 2020, prior to the commencement of the Chapter 11 Cases, the Company entered into a commitment letter (the “Commitment Letter”) with certain of the lenders under the pre-petition revolving credit facility and/or their affiliates (collectively, the “Commitment Parties”), pursuant to which, and subject to the satisfaction of certain customary conditions, including the approval of the Bankruptcy Court, the Commitment Parties agreed to provide the Debtors with a post-petition senior secured super-priority debtor-in-possession revolving credit facility in an aggregate principal amount of up to approximately $2.104 billion (the “DIP Credit Facility”), consisting of a revolving loan facility of new money in an aggregate principal amount of up to $925 million, which includes a sub-facility of up to $200 million for the issuance of letters of credit, and an up to approximately $1.179 billion term loan that reflects the roll-up of a portion of outstanding borrowings under the pre-petition revolving credit facility. Pursuant to the Commitment Letter, the Commitment parties have also committed to provide, subject to certain conditions, an up to $2.5 billion exit credit facility, consisting of an up to $1.75 billion revolving credit facility (the “Exit Revolving Facility”) and an up to $750 million senior secured term loan facility (the “Exit Term Loan Facility” and, together with the Exit Revolving Facility, the “Exit Credit Facilities”). The terms and conditions of the DIP Credit Facility are set forth in the Senior Secured Super-Priority Debtor-in-Possession Credit Agreement (the “DIP Credit Agreement”) attached to the Commitment Letter. The proceeds of the DIP Credit Facility may be used for, among other things, post-petition working capital, permitted capital investments, general corporate purposes, letters of credit, administrative costs, premiums, expenses and fees for the transactions contemplated by the Chapter 11 Cases, payment of court approved adequate protection obligations, and other such purposes consistent with the DIP Credit Facility. The terms and conditions of the Exit Credit Facilities are reflected in an exit facilities term sheet attached as an exhibit to the Restructuring Term Sheet (the “Exit Facilities Term Sheet”). The obligations of the lenders to provide the Exit Credit Facilities are subject to satisfaction of certain conditions set forth in the Exit Facilities Term Sheet, including conditions requiring (i) a minimum liquidity of $500 million, (ii) a leverage ratio no greater than 2.25:1.00 and (iii) asset coverage of credit facilities to PV-10 of at least 1.50:1.00. The DIP Credit Facility was approved by the Bankruptcy Court on a final basis on July 31, 2020 and became effective as of July 1, 2020.

*Executory Contracts.* Subject to certain exceptions, under the Bankruptcy Code, we may assume, assign, or reject certain executory contracts and unexpired leases subject to the approval of the Bankruptcy Court and certain other conditions. Generally, the rejection of an executory contract or unexpired lease is treated as a pre-petition breach of such executory contract or unexpired lease and, subject to certain exceptions, relieves us from performing our future obligations under such executory contract or unexpired lease but entitles the contract counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. Counterparties to rejected contracts or leases may assert unsecured claims in the Bankruptcy Court against our estate for such damages. Generally, the assumption of an executory contract or unexpired lease requires us to cure existing monetary defaults under such executory contract or unexpired lease and provide adequate assurance of future performance. Accordingly, any description of an executory contract or unexpired lease with us, including where applicable a quantification of our obligations under any such executory contract or unexpired lease of us, is qualified by any overriding rejection rights we have under the Bankruptcy Code.

*Potential Claims.* We have filed with the Bankruptcy Court schedules and statements setting forth, among other things, the assets and liabilities of us and each of our subsidiaries, subject to the assumptions filed in connection therewith. These schedules and statements may be subject to further amendment or modification after filing. Certain holders of pre-petition claims that are not governmental units were required to file proofs of claim by the deadline for general claims, (the "bar date"), which was set by the Bankruptcy Court as October 30, 2020. Governmental units were required to file proof of claims by December 28, 2020, the deadline that was set by the Bankruptcy Court.

As of November 5, 2020, the Debtors have received approximately 7,350 proofs of claim, approximately half of which represent general unsecured claims, for an aggregate amount of approximately $11.2 billion. We will continue to evaluate these claims throughout the Chapter 11 process and recognize or adjust amounts in future financial statements as necessary using the best information available at such time. Differences between amounts scheduled by us and claims by creditors will ultimately be reconciled and resolved in connection with the claims resolution process. In light of the expected number of creditors, the claims resolution process may take considerable time to complete and likely will continue after we emerge from bankruptcy.

*Going Concern*

The accompanying consolidated financial statements have been prepared assuming we will continue as a going concern and contemplate the realization of assets and satisfaction of liabilities in the normal course of business. Our ability to continue as a going concern is contingent on our ability to comply with the financial and other covenants contained in our DIP Credit Facility and our ability to successfully implement the Plan and obtain exit financing, among other factors. As a result of the Bankruptcy Filing, the realization of assets and the satisfaction of liabilities are subject to uncertainty. While operating as debtors-in-possession under Chapter 11, we may sell or otherwise dispose of or liquidate assets or settle liabilities, subject to the approval of the Bankruptcy Court or as otherwise permitted in the ordinary course of business (and subject to restrictions contained in the DIP Credit Facility), for amounts other than those reflected in the accompanying consolidated financial statements. Further, the Plan could materially change the amounts and classifications of assets and liabilities reported in the consolidated financial statements. The factors noted above raise substantial doubt about our ability to continue as a going concern. The accompanying consolidated financial statements do not include any adjustments related to the recoverability and classification of assets or the amounts and classification of liabilities or any other adjustments that might be necessary should we be unable to continue as a going concern or as a consequence of the Bankruptcy Filing.

**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:(a) | | | | |
| Basic | $ (6.37) | $ 9.21 | $ (11.89) | $ (35.53) |
| Diluted | $ (6.37) | $ 9.21 | $ (11.89) | $ (35.53) |

| | 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:(a) | | | | |
| Basic | $ (1.32) | $ (59.83) | $ (37.14) | $ 126.54 |
| Diluted | $ (1.32) | $ (59.83) | $ (37.14) | $ 113.80 |

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(a) All per share information has been retroactively adjusted to reflect a 1-for-200 (1:200) reverse stock split effective April 14, 2020. See Note 26 for additional information.

## 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) | Tota (mmb |
|---|---|---|---|---|
| **December 31, 2018** | | | | |
| Proved reserves, beginning of period | 260.2 | 8,600 | 218.6 | 1,9 |
| Extensions, discoveries and other additions | 56.3 | 1,162 | 19.8 | 2 |
| Revisions of previous estimates | (30.5) | 242 | 5.4 | |
| Production | (32.7) | (832) | (18.9) | (1 |
| Sale of reserves-in-place | (37.8) | (2,395) | (121.6) | (5 |
| Purchase of reserves-in-place | — | — | — | |
| Proved reserves, end of period | 215.5 | 6,777 | 103.3 | 1,4 |
| Proved developed reserves: | | | | |
| Beginning of period | 150.9 | 4,980 | 135.0 | 1,1 |
| End of period | 127.6 | 3,314 | 67.9 | 7 |
| Proved undeveloped reserves: | | | | |
| Beginning of period | 109.3 | 3,620 | 83.6 | 7 |
| End of period[(a)] | 87.9 | 3,463 | 35.4 | 7 |
| | | | | |
| **December 31, 2017** | | | | |
| Proved reserves, beginning of period | 399.1 | 6,496 | 226.4 | 1,7 |
| Extensions, discoveries and other additions | 62.7 | 3,694 | 44.9 | 7 |
| Revisions of previous estimates | (168.1) | (315) | (31.0) | (2 |
| Production | (32.7) | (878) | (20.9) | (2 |
| Sale of reserves-in-place | (0.9) | (418) | (0.8) | ( |
| Purchase of reserves-in-place | 0.1 | 21 | — | |
| Proved reserves, end of period | 260.2 | 8,600 | 218.6 | 1,9 |
| Proved developed reserves: | | | | |
| Beginning of period | 200.4 | 5,126 | 134.2 | 1,1 |
| End of period | 150.9 | 4,980 | 135.0 | 1,1 |
| Proved undeveloped reserves: | | | | |
| Beginning of period | 198.7 | 1,370 | 92.2 | 5 |
| End of period[(a)] | 109.3 | 3,620 | 83.6 | 7 |

(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 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*

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